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PRELUDE

Prescient building Operation utilizing Real Time data for Energy Dynamic Optimization

WP5 – Scale up and integration

D5.2 – VRE Integration Models

Version 1.0

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EXECUTIVE SUMMARY

This deliverable includes a description of the developed research methods, and it presents the results of the PRELUDE Task 5.2: VRE Integration Strategy. The goal of the task was to develop methods to study the impacts of several factors of variable renewable energy (VRE) integration in multi-apartment buildings, which provides valuable input to the apartment owners and residents in the decision making related to how VRE production could be sized, and how different flexible energy resources (ERs) could be used to support VRE integration. In this task, solar photovoltaic (PV) energy production is used as an example of VRE, which is well-suited for multi-apartment buildings, e.g., on the rooftops. In the investigations, electricity tariffs are accounted for as one economic factor, and actual measurement data was used as a starting point. The investigations were made by simulations, and different flexible ERs, such as battery energy storage system (BESS) and electric vehicle (EV) charging control, were included. The use of those ERs can be used, e.g., to facilitate larger solar PV systems as BESS can be used to store the surplus energy produced for later use, and EV charging control can be used to efficiently time the use of the produced energy. In the task, the impacts of different control algorithms of flexible ERs on VRE integration were studied. The methods presented help to verify the cost savings earned by the investor so that the profitability of different components of the multi-apartment buildings becomes clearer. Studies done with different tariffs, i.e., a more local aspect instead of country averages, help the apartment owners and residents to better understand and evaluate the potential and value of VRE investments. Lastly, these kinds of studies provide valuable information to the distribution system operators (DSO) that can be used when novel pricing schemes are determined for different types of customers in the future. The main takeaway from the results presented in this deliverable (Section 4) is that the use of an energy community (EC) model significantly increases the optimal solar PV system size in a multi-apartment building, which means that, this way, more solar PV energy can be produced compared to the present model. Thus, from a citizen perspective, effort should be placed into sizing the solar PV system to maximize annual cost savings for the multi-apartment building.

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ABBREVIATIONS

BESS	Battery energy storage system
CC	Combined control
CEC	Citizen energy community
DSO	Distribution system operator
EC	Energy community
ER	Energy resource
EV	Electric vehicle
LFP	Lithium ferrophosphate
MPC	Market price-based control
NRA	National regulatory agency
PSC	Peak-shaving control
PV	Photovoltaic
SC	Self-consumption-based control
SOC	State of charge
VAT	Value added tax
VRE	Variable renewable energy

1. INTRODUCTION

This task focuses on the development, selection, and implementation of systems and strategies to facilitate variable renewable energy (VRE) integration in the electrical energy grid. The key focus is on studying the impacts of VREs on residential buildings, i.e., the citizens as end customers, rather than on the electricity grid, i.e., the electricity distribution system operator (DSO), and to develop methods to assess the profitability of energy communities (ECs) and electrical energy resources (ERs). From an electrical energy system perspective, apartment buildings can form a new entity that possesses, e.g., solar photovoltaic (PV) panels on the building roof, electric vehicles (EVs) in the parking lot, battery electrical storage systems (BESSs), heat pumps, elevators, and other common electrical loads along with the electrical loads of individual apartments. That entity could be seen as a microgrid that can be operated optimally. Additionally, the residents of the apartment house can also form an EC, an actor in the energy market that is determined, e.g., as a citizen energy community (CEC) in the European Directive 2019/944 [1]. The EC can own common electrical ERs, such as solar PV panels on the building roof, and the benefits of those ERs can be shared among the members.

From a customer perspective, ECs can be a powerful tool in empowering citizens because, by participating in a collective that owns and utilizes different ERs together, they can, participate in the electrical energy market operation more actively than today, gain economic benefit by selling the energy produced inside the EC interface to the energy system when it exceeds consumption, and ensure that the electrical energy is produced with renewable energy sources. Today, the challenges are that, for an individual citizen, investments made into different ERs such as solar PV panels and battery energy storage systems (BESSs) might not be economically sensible as the costs exceed the benefits and the physical circumstances, e.g., shading conditions for solar PV production, might not be optimal. Additionally, for citizens living in apartment houses, it might not even be possible to install solar PV panels that are connected to the apartment. Through ECs, individual citizens can have better opportunities to collectively invest in ERs and situate them in optimal locations either directly inside the property boundaries or outside the property boundaries by using a separate line than in a situation, in which each citizen would have to make the investments individually and sub optimally. According to previous research conducted in the Finnish conditions, a solar PV system installed on the roof of an apartment house can be sized to be 2-3 times larger when a BESS is included [2].

In addition to the internal operation of the EC, it can also offer flexibility services and demand response possibilities for supplying the public electricity grid and the electricity market. The quality and accuracy of the metering data (e.g., acquired via smart metering) available is one key issue to model the operation of the EC; the more accurate the metering data , the more accurately the EC can be modelled and simulated. One task herein is to consider possibilities of smart meters to support the operation of an EC, e.g., an apartment house, by offering real-time measurement data and control functionalities.

This document focuses on the economic impacts of integrating different ERs into the electrical energy grid, specifically from an end user perspective in the case of ECs in different situations. The evaluation of the economic impacts of integrating VRE through ERs in ECs is done by simulations using real customer load data, electricity prices, and electricity distribution tariffs from Finland. Thus, the results presented in this document depict the impacts of different ERs on the ECs mainly in the Finnish electricity market and regulatory environment, but also data collected from the Geneva pilot case in Switzerland is used to broaden the analyses. The simulation model, described in more detail in (Section 3), includes several ERs, such as solar PV generation with optimal sizing, BESSs, EV charging control, and an electricity price-based control method of loads.

The results of the simulations show that forming an EC can strongly impact the economically optimal sizing of a solar PV system size in a multi-apartment building. More specifically, the EC model enables the sizing of the solar PV system to a much larger one than without it. However, there can be significant variation in the results depending on the load profile of the studied building. Different ERs, such as BESS and EV charging control have a significant effect on the sizing of a solar PV system, and the impact is higher in the case of ECs than in the current situation. The simulations also show that the price of electricity does not significantly affect the sizing of a solar PV system, but it has an impact on its profitability. Additionally, the ratio between different tariff components carries a small effect on the sizing of the system, but that impact is not dramatically large. However, when the tariffs depend significantly on the demand charge, the sizing of a solar PV system can prove difficult due to having to account for multiple maxima in the optimization task as shown in the Geneva demo case. In the Geneva demo case, significant benefits could be reached with even a relatively small solar PV system size. It is shown that the use of different control targets has only a slight impact on the sizing of the solar PV system, but the targets can be used to reach higher profitability levels. The VRE integration strategy should include the use of flexible ERs and the EC model to support the local use of VRE.

This deliverable is structured as follows. In Section 2, the research materials used in the task are introduced, which operate as the input parameters for the simulations. In Section 3, a description of the research methods that explain how different electrical ERs are included in the simulations is provided. Section 4 presents the results of the simulations done with the Finnish and Swiss data, and the analysis of the results about the economic impacts of different electrical ERs on the ECs that are considered here to be formed by apartment houses. Section 6 provides the conclusions of the work.

2. RESEARCH MATERIALS

In this section, the data that covers the electricity use and the relevant price elements used in developing the research methods and the simulation model are described. In developing the methods, data from Finland was used first as it was already available at the beginning of the PRELUDE project. Later, the data from the Demo Site #1 (Geneva, Switzerland) were made available through the Fusix API, and that data was then used to expand the analyses related to assessing the economic benefits of VRE through electrical ERs in ECs formed by apartment houses.

2.1 Data related to the electricity use

The data related to the electrical energy flows is a central input for the simulations. In this task, hourly (Finland) and quarter-hourly (Switzerland) electrical energy readings were used. The Finnish data covers the electrical energy loads of several apartment houses from the years 2016-2018, and the Swiss data (i.e., from Demo Site #1) covers the electrical energy readings from a single apartment house starting from mid-February 2022. In the following, the two datasets used in the simulations are described.

Data from Finland

The data from Finland that was used to develop the methods and investigate the economic impacts of VRE, electrical ERs, and ECs on different energy market actors includes the hourly electrical energy readings from six separate apartment houses that are situated in the capital area of Finland. The heating solution for each apartment house is district heating. In total, there are 228 separate points of electricity use in those 6 apartment houses, and most of the use points are for small-scale customers. The common consumption of each apartment house and the consumptions of each apartment were measured separately. To illustrate the overall electricity consumption of the apartment houses at a practical level, information about the consumption of each apartment house from 2018 is shown in Table 1.

Table 1: Information about the electricity use from the 6 apartment houses situated in Finland from 2018.

Apartment house	**1**	**2**	**3**	**4**	**5**	**6**
Number of customers	24	24	59	43	49	29
Number of floors	2-4	2-4	> 4	> 4	2-4	2-4
E_{annual} **(MWh)**	38.12	80.90	261.50	187.06	119.77	81.64
Lowest $P_{max,month}$ **(kW)**	7.32	21.95	49.65	31.21	23.61	28.32
Highest $P_{max,month}$ **(kW)**	12.36	27.99	59.89	55.50	33.40	40.56

(Note: E_{annual} here signifies the total annual energy volume and $P_{max,month}$ signifies the peak hourly demand of the month.)

The apartment houses do not yet possess electrical ERs, such as solar PV panels etc. Different electrical ERs were added to the simulations using appropriate methods, and those additions are depicted in Section 3.

Data from Switzerland (Demo Site #1 in Geneva)

The data from Switzerland consists of quarter-hourly electrical energy readings from a single apartment house. The demo site building has nearly 50 apartments and a population of approximately 110 people. In the apartment house, 10 apartments were recently renovated.

In Switzerland, the billing of electricity is done based on quarter-hourly data. The data package includes measurements from the electricity import, export, and the total consumption without the impact of solar PV production measured during the PRELUDE project. The EC in this case is considered to consist of the two highest floors of the building, and the measurements for the total electrical energy consumption are from those floors.

In measuring the data, some issues were identified. For instance, there were cases where some measurements were missing and, in some cases, the measurements were not logical. To correct the obvious errors in the measured data, the data was filtered and interpolated so that it could be used in the simulations. The actual measured values, which are cumulative values, were taken at minutes: 19, 28, 38, 49, and 60. Through data interpolation, the timestamps of the measurements were made uniform so that the dataset would correspond to the basis of electricity billing. In Fig. 1, an example of the principle used in data interpolation is shown for a period of one hour. In the figure, minute 0 depicts the value from the last minute of the previous hour before the example shown in the figure. The goal of the data interpolation was to determine values for minutes 15, 30, 45, and 60. Since the measured values are cumulative and the value increases at a constant rate, values could then be determined for the wanted timestamps. With this approach, the gaps in the data and the differences in the timestamps could be corrected, and a uniform representation of the data could then be reached to be used in the simulations.

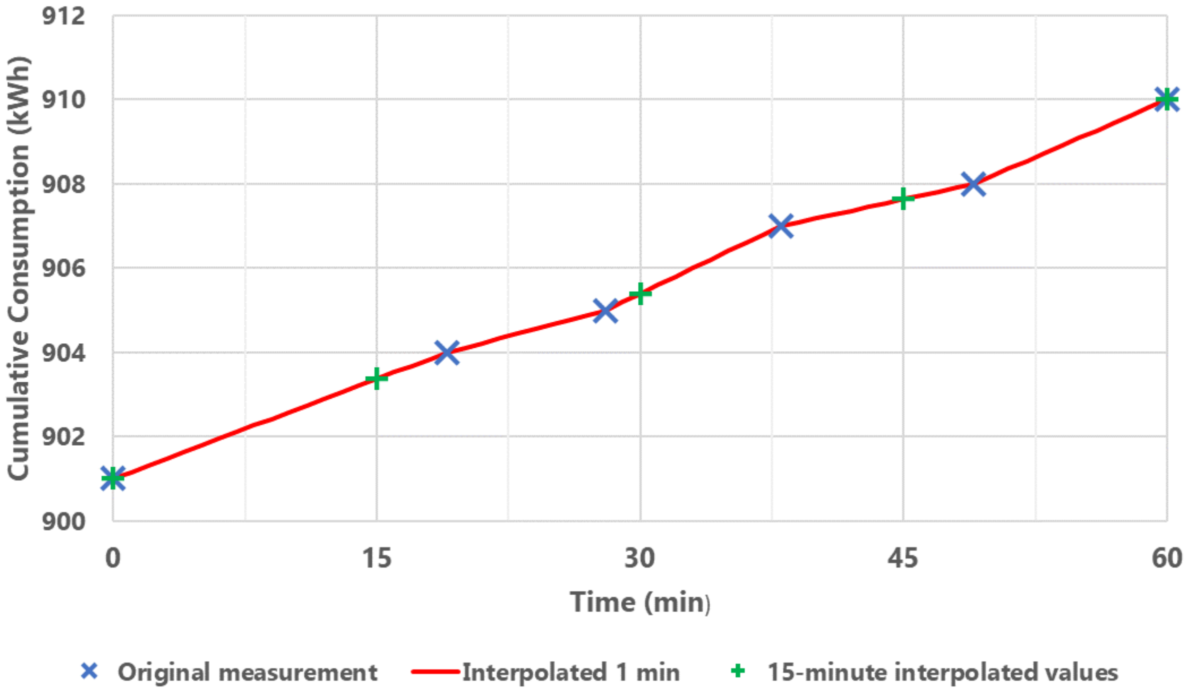

Figure 1: An illustrative example of the approach used in data interpolation and determining values for the target timestamps

In the simulations with the Geneva demo case data, measurements from a whole year were used. The investigation period starts in March 2022 and ends in February 2023. The sum of total consumption during that period was 51.4 MWh, and the maximum 15-minute average consumption was 22.3 kW.

2.2 Price data

The price data used in this task is taken from Finland and Switzerland. Because the energy readings became available later in the PRELUDE project, the Finnish data was used in most of the simulations. In the following, the price parameters for electricity that is relevant from the simulation perspective is presented in both the Finnish and the Swiss case.

Data from Finland

The Finnish electricity market is unbundled, and the customers typically receive different bills for the electrical energy (i.e., the retailer bill) and for the electricity distribution (i.e., the local distribution system operator (DSO) bill), and those two actors are treated separately in the analyses. Electrical energy and electricity distribution are also subject to taxes, and thus, the state is treated as a third actor in the analyses. In the following, brief descriptions of the three main electricity bill components of the citizen electricity bill that were used in the simulations (described in Section 3) are provided.

Electricity retail – Electricity retailer

The price data used in the simulations consist of hourly electricity prices in Finland from a 2016-2018 period, a margin that the electricity retailers use for the dynamic electricity rate contracts, and a fixed charge used by the retailer in addition to the two tariff components. Currently, there are approximately 60 electricity retailers operating in Finland, and, due to electricity retail being an activity subject to competition, the prices of the tariffs are unregulated. Thus, the margins and fixed charges of different retailers can vary significantly. For the simulations and analyses presented in this document, average values were calculated for the margin and the fixed charge of a dynamic electricity rate contract based on the public price lists of 53 Finnish electricity retailers. The average price parameters used for the dynamic electricity contract used in the simulations are shown in Table 2. The electricity retail tariffs in Finland are subject to a 24% VAT.

Table 2: Price parameters used in the simulations for the dynamic electricity retail contract (VAT 24%).

Fixed charge (€/month)	Retailer margin (c/kWh)	Hourly day-ahead prices of electricity from time interval
3.77	0.45	01/01/2016-31/12/2018

The reason for choosing dynamic electricity retail contracts in the analysis is that the hourly price variation of electricity offers the citizens better possibilities to become active and benefit from the low-price hours compared to the traditional fixed rate electricity contracts. If the customer has the possibility to adjust their demand based on the price of electricity, savings can be achieved at an individual customer level. Additionally, because during the high-price hours, the electricity is often produced with technologies that produce more emissions, ways to decrease the demand during those high-price hours must be pursued. Another way to lower emissions is to produce more clean energy. For instance, if the citizens possess different ERs, such as solar PV panels, and the electrical energy produced by those ERs exceeds the demand, the excess clean electricity can be then sold to the public electricity system at the hourly market price. Lastly, the BESSs can offer citizens more flexibility in pursuit of benefits if the electricity is stored temporarily to the battery and fed into the grid during high-price hours.

Electricity distribution – Distribution system operator

Electricity distribution business in Finland, as in other member states, is a monopoly activity that is operated by 77 DSOs. Electricity distribution tariffs are used to recover the costs of building, operating, maintaining, and developing the distribution system, and distribution tariffs are subject to regulation. In Finland, distribution tariffs are determined by the DSOs and the national regulatory agency (NRA), Energy Authority (in Finnish, Energiavirasto) oversees that the pricing is reasonable. The practices of who determines the distribution tariffs and how they are set varies between the member states. For instance, in some member states, the NRA has a significant role in setting the distribution tariff formats and prices whereas in other states, such as in Finland and Sweden, the DSOs can determine the distribution tariffs independently. Today in Finland, each DSO can determine their own tariff prices independently, but the basic tariff formats, i.e., the fundamental components, are quite similar. However, there are some differences in the billing parameters of different tariff components between the DSOs, such as the fixed charges being either tiered or uniform for different customer groups and there are several billing bases used for demand charges, especially those used for larger customers connected to the low-voltage network (i.e., both smaller and larger business and industrial customers.)

For the simulations, public price lists of 9 different DSOs were used to study the economic impacts of ECs on different actors. The distribution tariff prices and formats include variation in the fixed charges as some DSOs use tiered fixed charges and some use uniform fixed charges. Additionally, the billing bases of demand charges vary between the DSOs studied, e.g., from a monthly peak hourly demand to a moving 12-month peak hourly demand. The distribution tariff parameters used for small-scale customers (i.e., the maximum fuse size of 3x63 A) for the DSOs included in the simulations are presented in Table 3. The distribution tariffs used for larger customers (i.e., for connection sizes larger than 3x63 A) are shown in two parts (Tables 4 and 5). In Table 4, only the fixed charges and volumetric charges of the electricity distribution tariffs are presented. Table 5 presents the harmonized demand charges that were determined based on the turnovers generated with the present demand charges used by the 9 DSOs. The harmonization of the demand charges was done because the billing bases of demand charges used by the DSOs vary, and the harmonization made it easier to compare the economic impacts of the price levels of different DSOs in the simulations with uniform billing bases. Another reason for the harmonization is that, based on the recent recommendation made by the Finnish NRA in 2021, the billing bases of the demand charges of distribution tariffs are likely to be harmonized, and the most likely option for the demand charges used for larger customers is the monthly peak demand [3]. The total turnovers generated with the present demand charges were divided by the sums of monthly peak demands of the studied EVs that were calculated from the hourly energy readings. The calculated harmonized demand charges for three different billing options are depicted in Table 5. The basic principle of the process of determining the harmonized demand charges is illustrated further in Fig. 2.

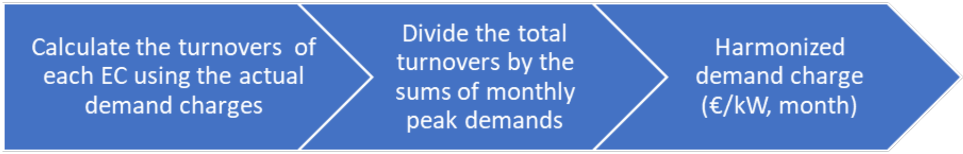

Figure 2: An example of the process of harmonizing the current demand charges used by the 9 DSOs for larger customers connected to the low-voltage network to correspond to a uniform billing basis.

Table 3: Prices of electricity distribution tariffs of the 9 DSOs that were used for small-scale customers (VAT 24%).

DSO (#)	**Fixed charge (€/month) Fuse size 3x25 A**	**Fixed charge (€/month) Fuse size 3x63 A**	**Volumetric charge (c/kWh)**
1	5.51	5.51	4.07
2	5.90	5.90	2.96
3	3.98	3.98	3.19
4	5.00	5.00	2.90
5	5.68	5.68	2.81
6	6.98	32.29	1.75
7	35.14	117.04	4.84
8	19.67	85.08	5.21
9	11.63	29.02	2.48

Table 4: Prices of electricity distribution tariffs (excl. demand charges) of the 9 DSOs that were used for larger customers connected to the low voltage network (VAT 24%).

DSO (#)	Fixed charge (€/month)	Volumetric charge (c/kWh) Winter workdays *	Volumetric charge (c/kWh) Other time
1	32.24	2.06	1.09
2	52.70	2.50	
3	213.18	1.18	1.72
4	40.00	1.86	1.36
5	50.93	1.62	1.14
6	136.40	0.84	
7	128.85	5.45	
8	63.82	3.55	
9	47.79	1.76	3.63

* Note: Winter workday hours in Finland are the hours from November 1st to March 31st, Mon-Sat, from 7 a.m. to 22 p.m.

Table 5: Harmonized demand charges used in the simulations for the 9 DSOs with three different billing bases (VAT 24%). The demand charges are calculated based on the load profiles and the turnover generated with the original demand charges used by the DSOs.

	Harmonized demand charge (€/kW)		
DSO (#)	Monthly peak demand	The average of 3 highest demands of the month	Moving peak demand from a 12-month interval
1	5.52	5.70	4.50
2	3.48	3.60	2.84
3	3.01	3.11	2.46
4	3.04	3.14	2.48
5	2.53	2.62	2.06
6	3.76	3.88	3.08
7	9.36	9.66	7.64
8	7.40	7.65	6.05
9	2.90	3.00	2.37

In the simulations, the focus is on groups of small-scale customers situated in either the same small geographical area or inside the same property boundaries who would form ECs. Currently, there are no separate electricity distribution tariffs in place for the EC customer segments. In the simulations, the economic impacts of several small-scale customers forming an EC are studied by using the tariffs shown in Tables 3, 4, and 5. Simply put, one goal of the simulation is to study if the present distribution tariffs used for larger low voltage customers (i.e., smaller commercial and industrial customers connected to the low voltage network) could be used for the studied ECs.

Taxes - State

In Finland, electricity is subject to an energy tax (2.24 c/kWh for most customers) and a security of supply charge (0.013 c/kWh), which total a charge of 2.253 c/kWh. [4] Additionally, those charges are also subject to a value added tax (24%). Thus, the citizen in Finland pays an energy tax of 2,79372 c/kWh (VAT 24%) and the electricity tax is collected by the local DSO. Electricity distribution is also subject to a 24% VAT.

Other issues related to electricity tariffs in Finland

In the case of ECs, the electricity tax can be avoided, if the energy transfers occur inside the property boundaries, e.g., between the rooftop solar PV panels and the point of use that are situated in the apartment house. Thus, the citizens living in apartment houses can achieve economic benefits, i.e., they pay less taxes, by forming an EC and investing in jointly owned electrical ERs. Additionally, based on the current legislation, if the apartment house forms an EC, and the use of a credit calculation model is bought as a service from the local DSO, then the internal electrical energy transfers that occur inside the property boundaries are not subject to electricity distribution tariffs. However, if the EC sells the locally produced electrical energy to the public electrical energy system, then that energy is subject to taxes and a maximum distribution network charge of 0.0868 c/kWh (VAT 24%), a cap set by the current legislation, for the injection. Many an electricity retailer in Finland buy the electrical energy produced via small-scale renewable electrical energy from the customer at the market price (i.e., the day-ahead hourly spot price of electricity.)

Data from Switzerland (Demo Site #1 in Geneva)

In Switzerland, there are hundreds of small electricity utilities that operate in relatively small areas, and because vertical integration is present across Switzerland, the local utility might provide the customer with both the electrical energy and electricity network services. The NRA in Switzerland is the Federal Electricity Commission (ElCom), which is responsible of monitoring the pricing, i.e., the tariffs and prices in the electricity sector.

For the Swiss demo case, the tariffs used were selected from the public price list of Services Industriels de Genève (SIG), which is the responsible local utility for electricity in Geneva that serves approximately 230,000 customers in the canton of Geneva. The tariff option used in the simulations was the "Tarif Pro BT" with the option "10% Vitale Vert", which is used for professional customers connected to the low-voltage network who consume more than 30 MWh annually, but the maximum demand is less than 500 kVA. [5] The tariff used by SIG for electricity includes the following items:

- Energy charge (ct/kWh).
    - There are four different rates for different time slots (i.e., for summer and winter, and for peak and off-peak hours.)
- Grid usage charge, which consists of a volumetric charge (ct/kWh) and a demand charge (CHF/kW), for two rate options, A and B, from which option A was selected for the simulations.
    - The volumetric charge has separate rates for peak and off-peak hours, which are the same for all seasons.
    - The demand charge has a single rate, and the billing demand is the maximum quarter-hourly demand of the year.
- Public service charge, which is calculated from the volumetric and demand charges of the grid usage charge (i.e., 13.2 % of the volumetric and demand charges).
- Federal supplement charge for the development renewable energies and water protection.

Electricity tariffs in Switzerland are subject to a 7.7 % VAT. The price parameters, including VAT, used in the simulations are shown in Table 6. The rates shown in the table are based on the price list of SIG [5], and the prices are converted from CHF to EUR with a currency ratio of 1 CHF = 1 EUR (at the time of writing this text, the ratio was 1 CHF = 1.02 EUR). The remuneration item on the last row of the table is based on [5], but, as shown in [6], in Switzerland, the magnitude of the feed-in remuneration rate varies significantly between the companies. The price data shown in the table is based on [5] (items of the electricity bill) and [6] (remuneration for the surplus PV energy feed-in).

Table 6: Price parameters (in EUR, incl. VAT 7.7%) that were used in the simulations done with the Swiss demo case data. The information shown in the table is based on [5] and [6].

Electrical energy

Summer (c/kWh)	Peak	13.14	From Apr. 1st to Sept. 30th For Mon-Fri hours between 07-22 For Sat-Sun hours between 17-22
	Off-peak	8.94	For other hours
Winter (c/kWh)	Peak	14.16	From Oct. 1st to Mar. 31st For Mon-Fri hours between 07-22 For Sat-Sun hours between 17-22
	Off-peak	9.64	For other hours

Electricty grid usage charge

Volumetric charge (c/kWh)	Peak	7.38	Mon-Fri hours between 07-22 Sat-Sun hours between 17-22
	Off-Peak	4.47	Other hours
Demand charge (€/kW)	6.89		Peak quarter-hourly demand of the year

Public service charge (13.2% of the components of the electricity grid usage fee)

Peak vol. charge (c/kWh)	0.90	
Off-peak vol. charge (c/kWh)	0.55	
Demand charge (€/kW)	0.91	

Other components

Federal supplement charge (c/kWh)	2.30	
Remuneration for the surplus solar PV energy feed in (c/kWh)	15.50	Paid to the customer for the electrical energy injected to the public electrical energy system

3. RESEARCH METHODS AND SIMULATION MODEL

This section presents the different electrical ERs that were modelled in the simulations to study VRE integration in a multi-apartment building. In integration VRE, several models and components can be used either individually or together. In this task, for VRE production of electrical energy, solar PV panels were selected as an example to represent the electrical energy production form.

3.1 ENERGY COMMUNITY MODEL

Between different countries, the practices can vary regarding how the electricity contracts are made between the customers and the utilities or suppliers in multi-apartment buildings. In this section, the current practice in place in Finland is presented as an example, and the following text is written mainly from a Finnish perspective.

In multi-apartment buildings, the parties who make the contracts can vary, e.g., the parties on the customer side can be either the apartment owners or the tenants. Utilizing VRE to cover the consumption of individual apartments can thus be problematic in some cases if several parties are involved in the contract making. To distinguish how much electricity each apartment uses, and to ensure that the customers can make the contract with the local DSO and with electricity contract with the retailer of their choosing, the electricity use of each apartment must be measured separately.

Today, in apartment houses, the practical solution to integrate VRE is to install solar PV panels on the building rooftop. The produced electrical energy is used for the consumption of the common loads of the building, which fall under the electricity contract of the housing company, not the individual apartments. If the production units and the loads are situated behind the same meter (or a connection point), the produced electrical energy can be consumed locally. In that case, no electricity distribution fees, or electricity taxes must be paid for the internal electrical energy transfers. If the produced electrical energy would be used in the apartments, i.e., the electricity flows through several electricity meters, then electricity distribution fees and electricity taxes must be paid for the electrical energy transfers. However, as mentioned above, the practices regarding how the electrical energy transfers in multi-apartment buildings are treated in different countries can vary.

To use the electrical energy produced by the solar PV panel in a multi-apartment building more widely at a local level, the building could form an EC, i.e., the whole building would be treated as a single customer. This way, the electrical energy produced by the solar PV panels can be used for both the common loads of the building and the apartments without the internal electrical energy transfers occurring inside the EC being billed for electricity distribution fees or electricity taxes. The principles of how the electricity metering would work in a multi-apartment building under the current model and EC model are shown in Fig. 3.

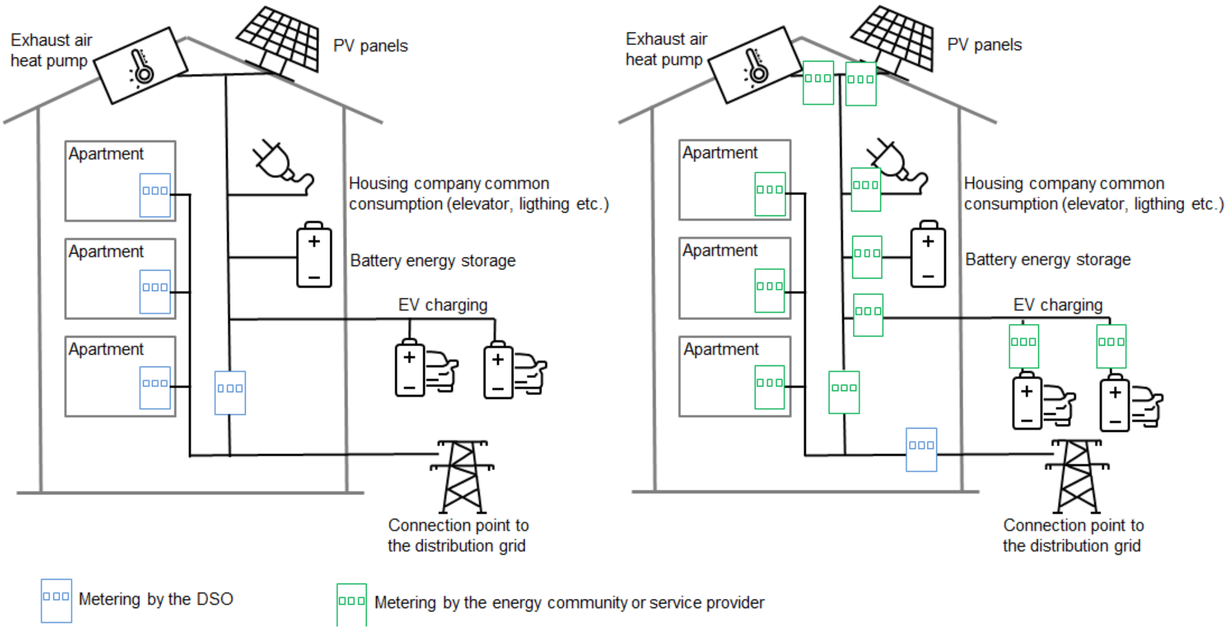

Figure 3: Forming energy community in the multi-apartment building. Initial metering infrastructure (left) and electricity metering principle in energy community model (right)

In the EC model, electricity meters are required for each apartment and the common loads of the building to share the costs and benefits between the members. An interesting item in the EC model depicted in Fig. 3, where the consumptions of individual apartments are involved in the total consumption of the building, which is treated as a single customer, is that it may be possible to profitably increase the size of the solar PV system to a larger system compared to the situation where the production would be used only for the common loads of the building. Ways to increase the size of the solar PV systems are an important target to pursue to increase the amount of renewable electrical energy production, and, to model in integration of VREs in multi-apartment buildings as ECs is a central item in this task. The principles of how the solar PV system can be sized are presented later in Section 3.6.

On the practical side, the demo case situated in Geneva, Switzerland that consists of a multi-apartment building included in the PRELUDE project was studied in this task. The two highest floors of that building, which include 10 apartments and common loads, form an EC. In the building, there is a 21 kWp solar PV system and a 20 kWh lithium-ion battery that are the common electrical ERs.

3.2 PHOTOVOLTAIC PRODUCTION

The most important form of VRE production, in terms of electricity, in residential buildings, and particularly in multi-apartment buildings, is solar PV production. Solar PV panels can be installed on the building rooftop and the electrical energy produced can be used directly for the needs of the building. Additionally, as a means of producing electricity, rooftop solar PV can be used widely in urban settings. When the utilization of solar PV production in residential buildings is being studied, the focus should be on the production profile. There are different methods to form a solar PV production profile for a building under study. In the best situation, actual measurements for the produced electrical energy should be used if they are available. If actual measurements are not available, the production profile can be determined by simulations, which can be based on the measured solar irradiance near the building location or, in some cases, the irradiance must also be simulated using the knowledge about the location of the Sun in relation to the studied building and the cloudiness probability at the building location.

The Geneva demo site location included in the study of this task has a 21 kWp solar PV system on the building roof, and the production was measured. Thus, in the study, actual production measurement data was used. The measurements for the solar PV production were similar to the electrical energy consumption measurements (see Section 2.1), and thus, the data had to be interpolated to determine the values for the production to match the timestamps of the interpolated consumption data. The total produced electrical energy during the study period (i.e., between March 2022 and February 2023) was 25.2 MWh, which corresponds to approximately half of the total consumption during the study period. The production profile in the Geneva demo case is shown in Fig. 3 at a 15-minute resolution. Data interpolation was used to fill in the gaps that were present in the measurements.

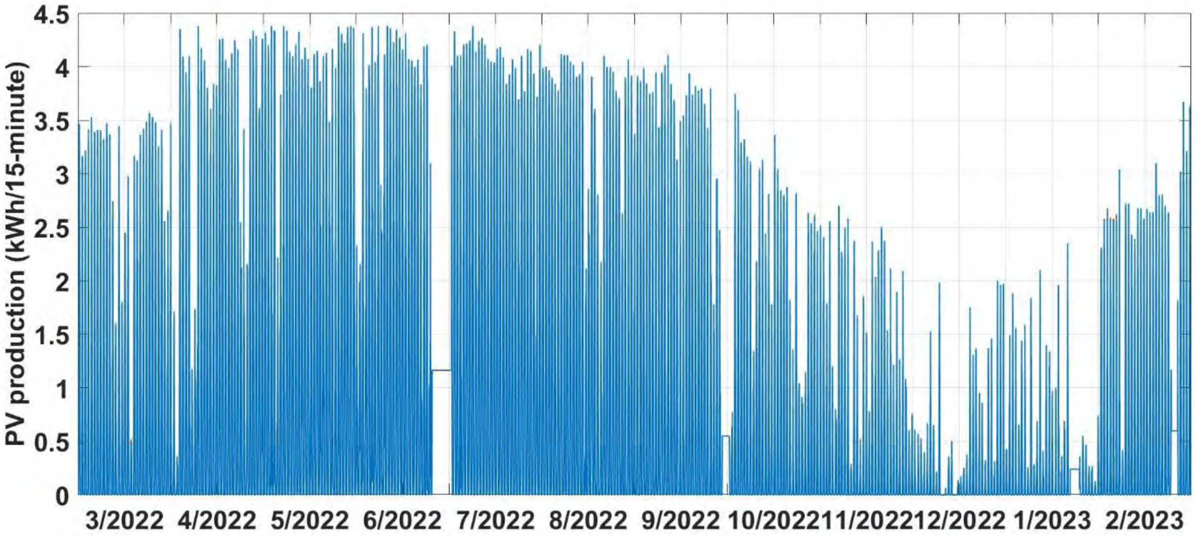

Figure 4: Geneva demo case PV production profile in studied period by using 15-minute time steps with interpolation and timing

In this task, in addition to the Swiss data, data from Finland was used in the simulations. In the buildings situated in Finland, there were no solar PV systems, and, because of that, the production profile had to be formed by using irradiance measurements. The buildings of the study are situated in the capital area of Finland, and the Finnish meteorological institute (FMI) provides open data that covers the irradiance measurements for that area [7]. The total irradiance, which reaches the surface of the solar PV panels can be divided into three components: beam, diffuse and reflected irradiances. Measurements made by the FMI includes all those components for a horizontal surface. The beam irradiance reaches the surface of the solar PV panel directly from the Sun, the diffuse irradiance is reflected from the particles in the sky e.g., clouds, and the reflected irradiance reaches the surface of the solar PV panel through reflections from other physical objects, e.g., buildings, roofs, or the earth surface. By utilizing the Reindl model, the total irradiance G_i for a tilted solar PV panel surface can be modeled [8]. PV production P_{pv} can be calculated by using equation:

$$P_{PV} = P_{STC} G_i \big(1 - 0.006(T_c - 25°C)\big),$$

where P_{STC} is the nominal power of PV system in standard test conditions (STC) and T_c is the solar cell temperature. When the measurements for the solar cell temperature do not exist, the estimation can be formed by utilizing the intensity of irradiance and outdoor temperature measurements. The production profile for a 1 kWp solar PV system in the capital area of Finland is shown in Fig. 5. If in Finland the PV system size will be similar than in Geneva demo case, then the maximum production is almost the same, but the production outside of summertime is significantly lower. With a 21 kWp solar PV system, the total annual production would be only 15.2 MWh, which is approximately 10 MWh lower than in Geneva. This example shows how much the location of the solar PV system affects the annual production in Europe (the parallel of latitude in Geneva is 46° whereas in Helsinki it is 60°).

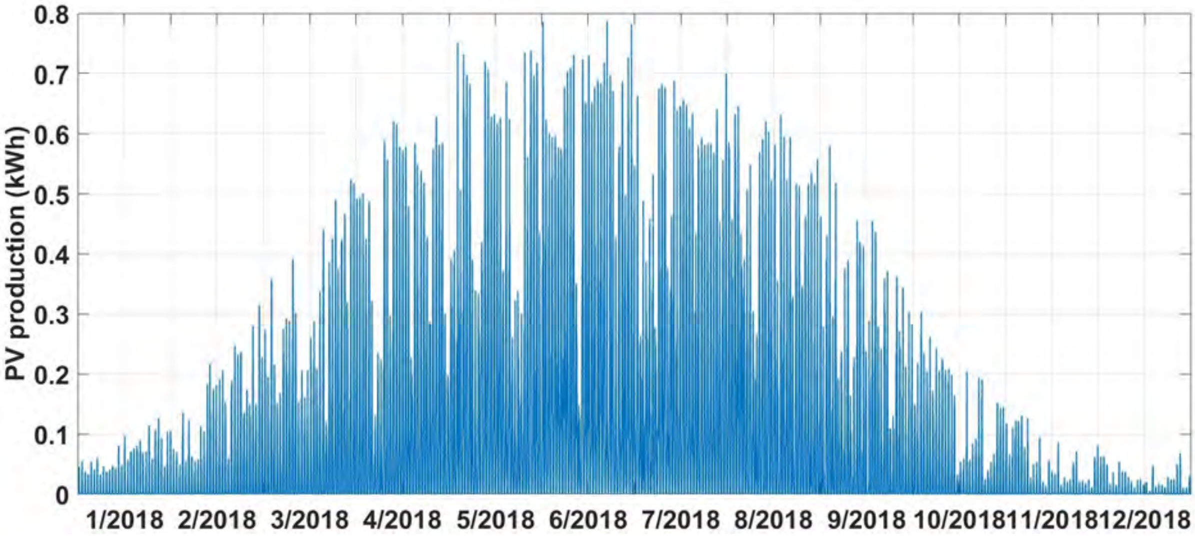

Figure 5: PV production profile in capital area of Finland with 1 kWp PV system and an hour time step

3.3 BATTERY ENERGY STORAGE

The fundamental idea is to charge the surplus energy into the BESS and use the stored energy later, when the consumption is higher than the production. There exist several battery chemistries for this use, but nowadays, there are two main options. Lead acid batteries are typically used, when a lot of cheap surplus energy is available, because they are very inexpensive batteries compared to their storing capacity. However, lead acid batteries are heavy and require a lot of space. In residential buildings, where the solar PV system is used, the problem of lead acid batteries is their low efficiency. The profitability of storing the surplus energy depends on the price difference between the electricity purchase price and the price of selling the surplus electricity to the grid. Usually, this difference is so low that the efficiency of the BESS must be very high. Hence, nowadays, lithium-ion batteries represent the only possible battery chemistry, which is widely commercialized.

In this task, in the Finnish case, lithium-ion battery is studied, where the cathode material is lithium ferrophosphate (LFP). LFP is a very safe battery chemistry, and it has a high efficiency and a long lifetime that make it well-suited for residential use. In the Geneva demo case, LFP based BESS is used [9]. In residential use, the battery has three important features, which strongly affect the use of BESS. These features are capacity, power (i.e., the C-rate), and efficiency. In the simulations, it was possible to size the battery capacity to fit the load profile optimally. The maximum charging and discharging powers depend on the C-rate of battery, which means the ratio between the battery capacity and power (e.g., a 2 kWh battery with a 0.7 C-rate means that the maximum power is 1.4 kW). The C-rate depends on the power electronics of the battery and how the BESS is designed. The way how the battery is used, in terms of power, also affects the efficiency of the battery, which is in a key role in modelling the battery. The BESS model used in the simulations calculates the efficiency during each moment depending on how the battery is being used. Using high powers decreases the efficiency of the battery but enable to quickly store a high amount of energy. Thus, it is important to find the right balance between the powers used.

The BESS used in the Geneva demo case includes a battery with a 20 kWh capacity and a 0.25 C-rate. This means that it is possible to charge or discharge approximately 5 kWh of energy during a single hour. Low C-rate means that the efficiency is very high, approximately 97.5 %. In many cases the high power is a more valuable feature that a very high efficiency. In simulations done with the Finnish data, a similar battery chemistry is used than what is used in the Geneva demo case, but the C-rate of the battery is 0.7. This means higher charging and discharging powers, but lower efficiency, which in the simulations is approximately 95.7 %. These efficiencies describe the efficiency during one charging or discharging process, so the round-trip efficiencies is lower (In the Geneva demo case, the value is approximately 95.1 % and in the Finnish case, the value is 91.5 %). The size of the studied BESS in simulation cases made with the data from Finland is also 20 kWh.

3.4 ELECTRIC VEHICLE CHARGING CONTROL

It is to be expected that the share of electric vehicles (EV) in the car fleet will increase in the future. the charging of EVs consume a lot of electricity and the increasing number of EVs will increase the total electricity demand in the electrical energy system. Many car users have typical times of using EVs and the driving patterns repeat every week in a nearly similar fashion. Thus, typical times when the EV is unused can be identified. These times of unuse are the potential time slots for charging the battery of the EV. Without smart charging options, the user connects the EV to the charging station as soon as the drive ends, and the charging start immediately. Smart charging options enable to schedule the charging during periods when the EV is unused.

In this section, the way the EV charging control is modelled and used, and what are the impacts of those factors, are presented. No actual measurements about the EV charging were available during the PRELUDE project, and the modelling is based on driving statistics from Finland (i.e., the National Travel Survey [10]), which can be used to evaluate the potential of EV charging control. In different countries, there can be differences in how the car users behave, and the statistics might be different. In Finland, the driving distances are long, because the country is sparsely populated.

The probability of the number of cars per apartment in a multi-apartment building is shown in Fig. 6. By using these probabilities, it is possible to make a table that presents the number of cars for every apartment in the building. In Finland, the target for 2030 is that there would be approximately 600 000 plug-in EVs, which would equal to approximately 22% of all the cars in Finland, and, additionally, the target for EVs is that at least 50% of those vehicles are full EVs [11]. Because of those targets and ratios, in the simulations, 11% of all the cars in the multi-apartment buildings are assumed to be full EVs and 11% plug-in hybrid EVs. With those assumptions, the number of full EVs and hybrid EVs per apartment can be modelled. The simulations show that that the apartments have either 0, 1, or 2 cars. The apartment occupants who have 3 or more cars are rare, and those occupants are not considered in the simulations. From the group of cars, EVs are selected at random.

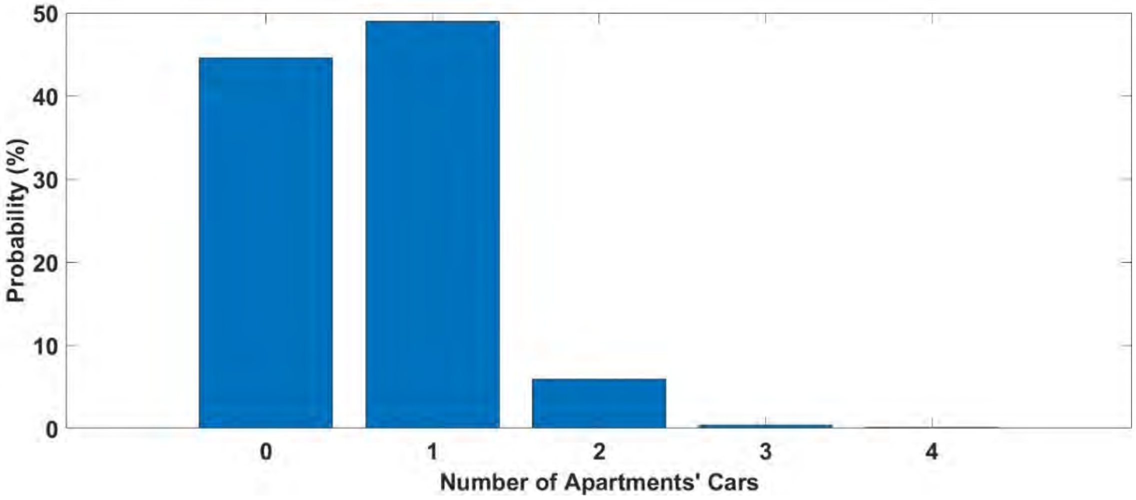

Figure 6: Probabilities for the number of apartments' owners' cars

After the number of EVs has been determined, the next task is to determine what the driving distances of those EVs are. The probabilities for different annual driving distances are shown in Fig. 7. There are separate probabilities for cars, which are the only car for the apartment, and for cars in apartments, where the occupants have two cars. The probabilities are shown for annual driving distances in 2,000 km steps. For instance, if the probability that is based on a random number generator provides a driving distance that is in the range 10,000-12,000km, then a value of 11,000 km is used in the simulation model. The probability-based modelling for driving distances is done for all the modelled EVs.

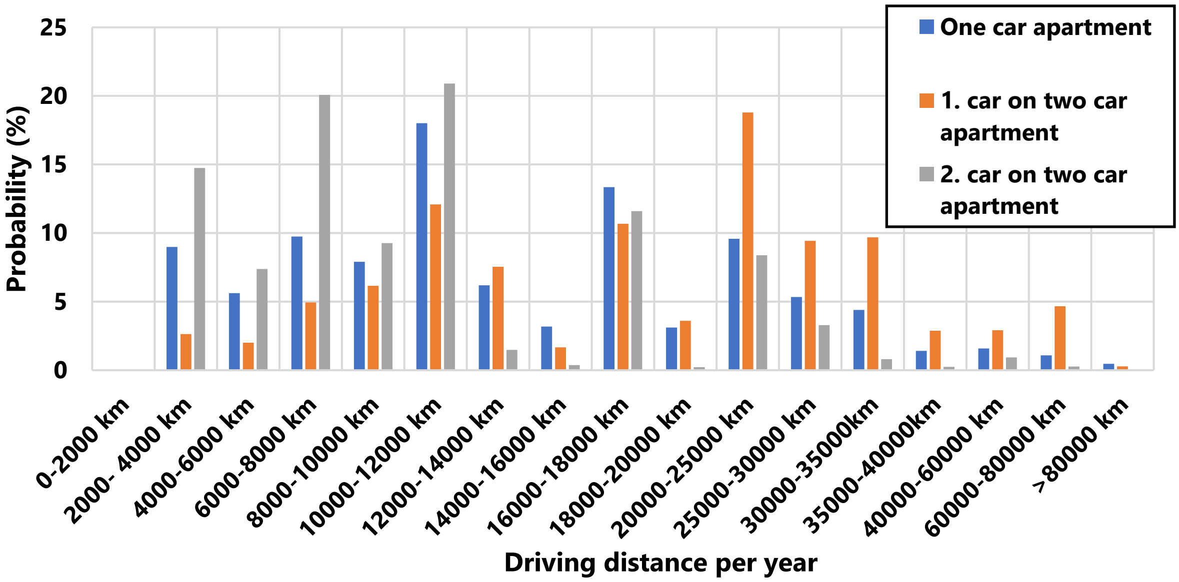

Figure 7: Probabilities of yearly driving distances

After the driving distances have been determined, driving times per day for the modelled EVs must be determined. The probabilities for driving times per day are shown in Fig. 8. In the simulations, the driving time per day is modelled for every EV for all days of the study period. For days that have a high number of driving times per day, the probability is low, and the probability is the highest for days that do not include any driving. In the figure, one driving time per day means that the car leaves home and comes back again. For instance, this could mean that the car is driven to the workplace in the morning, and it returns home in the afternoon. If a day includes driving, the most likely value for the driving times per day is 2 as observed from Fig. 8.

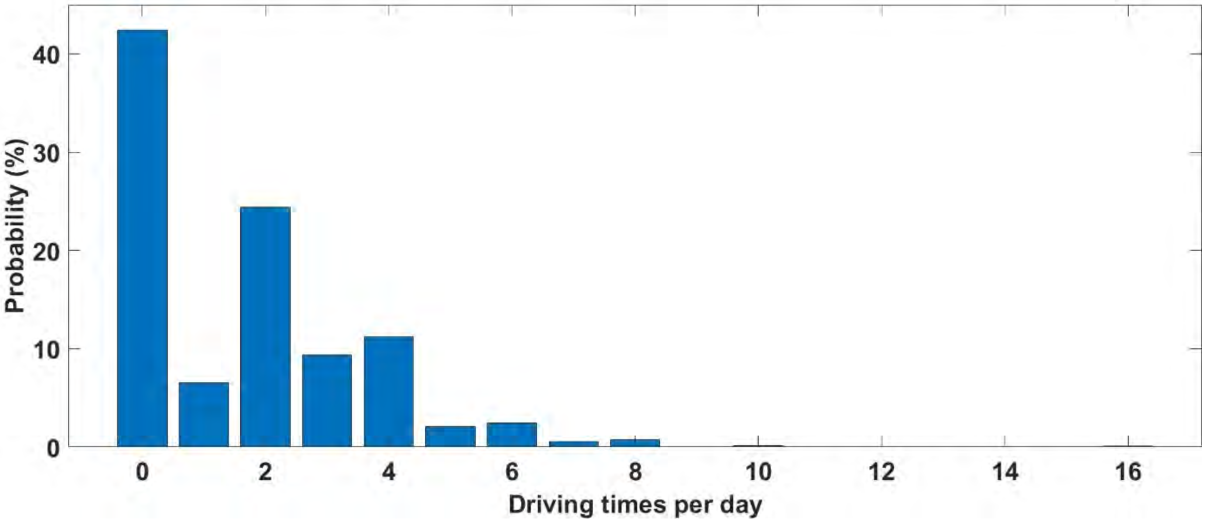

Figure 8: Probabilities for the driving times per day

When the EV charging is being simulated, it is important to know when the EV is at home so that the possible time slots for the charging can be determined. The probabilities for times when the car is leaving home are shown in Fig. 9. For different days of the week, e.g., for weekdays and weekends, the probabilities are different. In the modelling, the driving times have been determined for every day, and thus, based on that information, the times for when the car leaves home and when the energy required must be charged to the battery of the EV can be modelled. If the number of driving times per day is larger than 1, then the departure times cannot occur during the same hour. The departure times are modelled for the days that have driving times. As observed from Fig. 9., during weekdays, the most likely departure time is at 8 a.m., and during weekend, the most likely departure time is at 11 a.m.

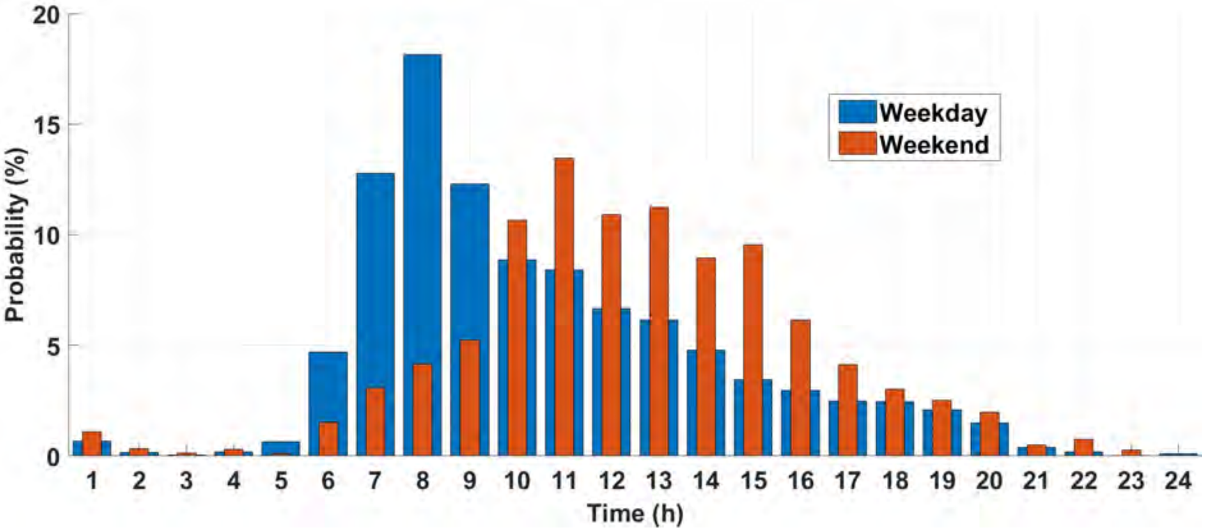

Figure 9: Probabilities for the departure times

The probabilities for the arrival times of the cars during weekdays are shown in Fig. 10., and the probabilities for weekends are shown in Fig. 11. Naturally, the arrival time must be later than departure time, but probability of arrival time depends on the departure time. Thus, there are different probabilities for the arrival times with different departure times. In the simulations, the arrival times have been modelled, and based on those times, the arrival times can then be modelled for the trips made. If the day includes more than one driving time, only the probabilities of the arrival times between the departure times are considered in the modelling. Naturally, the last departure time of the day is modelled normally as the only trip of the day. In the simulations, it is assumed that the EV returns home every day before midnight. As the departure and arrival times are now known, a timetable can be formulated that depicts when the EV is at home and when it is away.

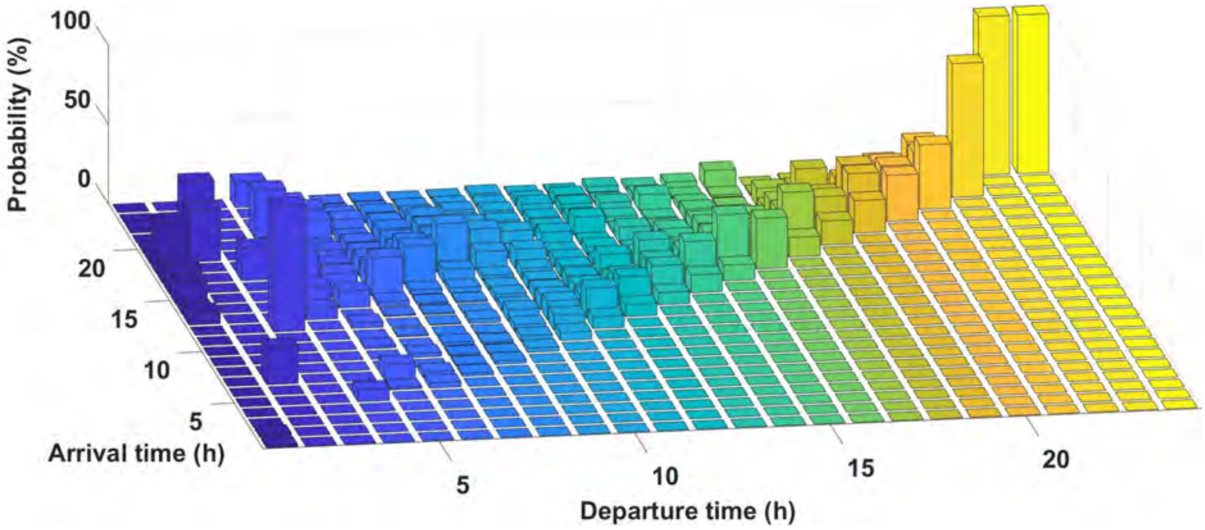

Figure 10: Probabilities for the arrival times on weekdays

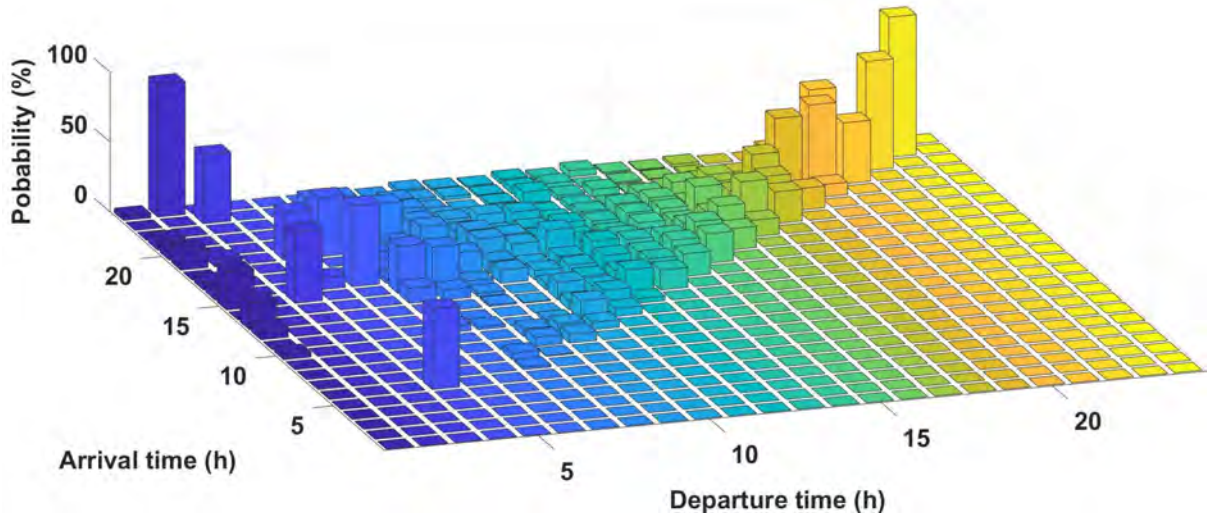

Figure 11: Probabilities for the arrival times on weekends

Next, the lengths of the trip during every driving time must be modelled. As now the annual driving distances and timeslots of the trips have been modelled, the lengths of the driving trips can be determined by using a random number with the normal distribution. The mean value of the normal distribution is the average distance of all the trips that the EV makes, and the standard deviation is that same value. With this approach, the annual driving distance corresponds to the modelled driving distance, however, there is variation between the trips. A set of limitations must be determined in the modelling of the driving distances of the trips. The minimum driving length of the trip is set to 2 km, and the maximum distance per hour is set to 100 km. The driving distance is distributed over all the hours of the driving trip, and the car cannot exceed 100 km per trip considering the speed limits in Finland.

In the modelling, two types of EVs are considered, full EVs and plug-in hybrid EVs. It is assumed that the typical battery size in a full EV is 60 kWh and in hybrid EVs, the battery size is 9 kWh, and the typical electrical energy consumption of an EV is 180 Wh/km [12]. In the beginning of the simulation, the initial SOC of the EV battery is set to full. During the simulations, the SOC changes based on the driving distances and EV charging. The charging efficiency is set to 90 %, which means that the charging causes electrical energy losses. EV charging is done in the electricity network of the apartment building, where the maximum charging power is 3.7 kW (16 A) per EV. In a normal situation, the charging starts immediately when the EV returns home and the charging cable is plugged in, but as the charging is controlled in the simulations, the start of the charging can be delayed.

An example of the annual variation of the SOC for the EV is shown in Fig. 12 that depicts how the battery SOC of a one randomly selected full EV changes over time. Most of the time the battery is full, and during typical trips, the SOC decreases to a level that is approximately between 60% and 80%. There are a few times (two in the example shown in Fig. 12) when the battery SOC decreases to zero, i.e., the battery is empty. The battery of a hybrid EV will be discharged down to zero more often than a full EV. This means that the EV must be charged in some other location than home, because in those situations, the EV is not at home. When the SOC is zero, the hybrid EV uses its combustion engine and full EVs must be recharged at a public charging station. In that situation, the charging is not considered in the EV charging control model. In the simulations, the interesting research question is how much the number of situations for when the battery is empty increases when the charging control delays the start of the charging.

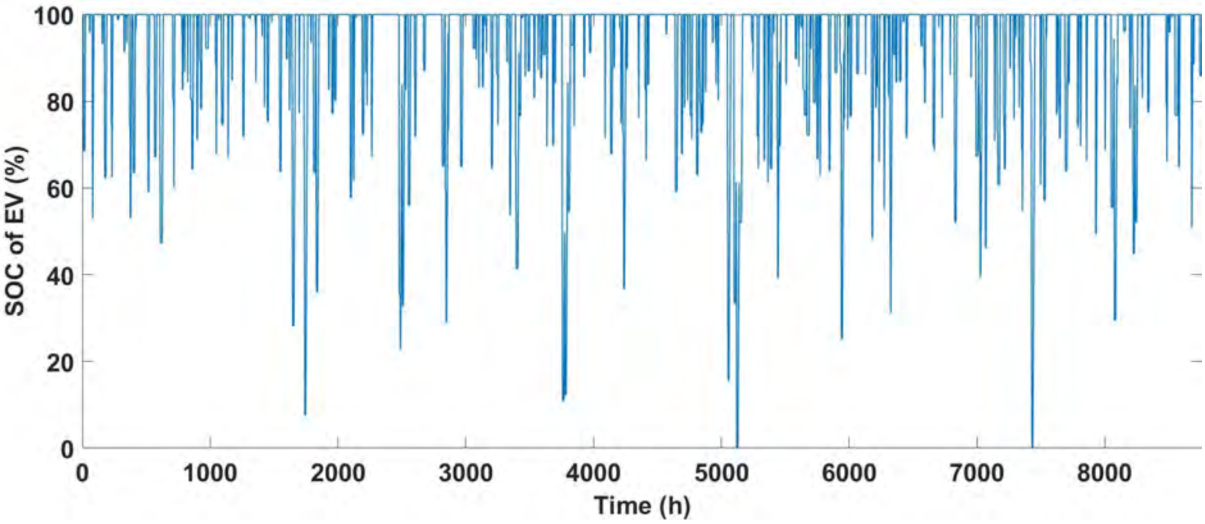

Figure 12: SOC of a full EV during a year

In the simulations, the target is to model the charging demand of all EVs of the apartment house. An example of the hourly charging powers from one apartment building, in which there are 3 full EVs and 2 hybrid EVs for one year period are shown in Fig. 13. For most of the time, there is at least one EV that is being charged, but only very rarely there are more than one EV being charged at same time. There are no cases for when more than three EVs are being charged simultaneously. The example shown in Fig. 13 does not include EV charging control. By using a delay for starting the charging, it is possible to avoid simultaneous charging of several EVs. However, by avoiding the simultaneous charging is not the target of the simulations, but rather to study how controlling the EV charging can help to integrate VRE production in apartment buildings. To reach this target, the delay of starting the charging can be used to better time the charging so that the solar PV production can be used to charge the battery, or the total electricity costs can be decreased.

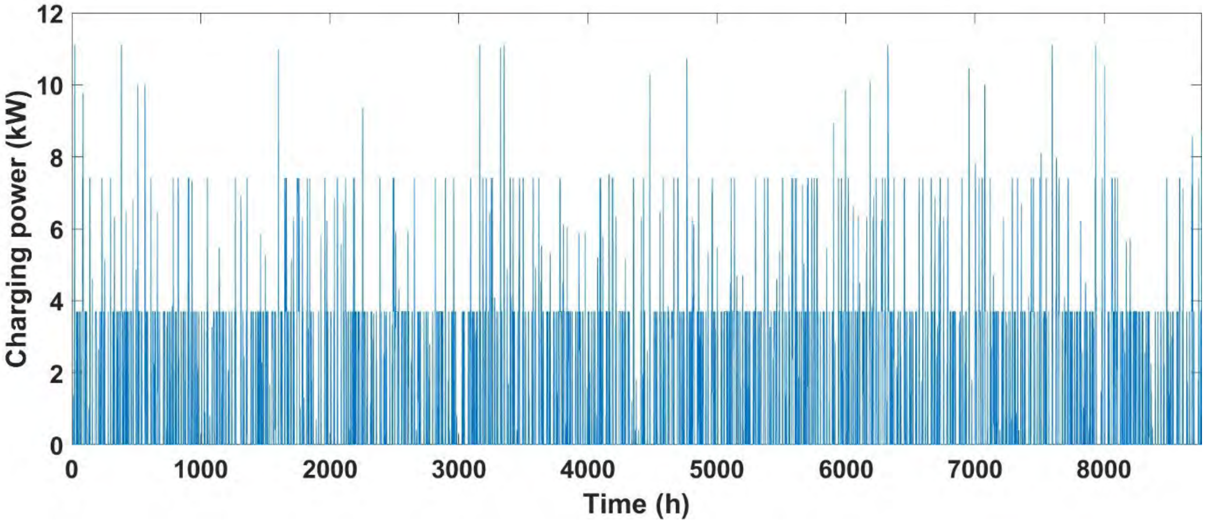

Figure 13: Total charging demand of 3 full EVs and 2 hybrid EVs without controls

3.5 CONTROL SYSTEM

Smart controlling makes it possible to utilize different electrical ERs efficiently. For investors, the economic profitability is the most important factor when investment decisions regarding ERs are being made. There are three key factors that affect the profitability of ERs, the first being the investments costs, the second being the sizing of the ERs, and the third being the use of ERs. The costs during the time of the investment are usually known, and the sizing must be done before the investment. By using a smart control system, it is possible to maximize the economic benefits of the ERs.

The electricity costs of a customer depend on the load profile. By using different ERs, the load profile can be modified so that minimize the electricity costs. Solar PV production decreases the consumption during daytime, and the produced amount is higher during summer than in winter. Additionally, on occasion, the production during daytime might exceed the consumption, and the production surplus can be sold to the electrical energy system. Because of electricity tariffs, it is often more profitable to decrease the amount of electricity being purchased from the electrical energy system than to sell the production to the electrical energy system. The tariffs might also include demand components (i.e., components based on the maximum power), and decreasing the maximum peak demand can be profitable. These kinds of factors create incentives to modify the customer load profiles. In this task, BESS and EV charging control are included as controllable flexible resources.

Three different incentives were studied in this task, which form the fundamental targets of the control system. The first target is to increase the self-consumption rate, the second is to minimize the maximum demands, and the third is to achieve economic benefits through market price-based control. When the increase of self-consumption rate is the target, the control algorithm is very simple. If there is a surplus of energy available, then the BESS is charging. When the consumption rises to a level that is higher than the production, the BESS is discharged. The discharging can be delayed when other targets are being pursued. The EV charging control is based on forecasting. For the control system, the consumption and production must be forecasted so that the possible times when energy surplus is available can be identified. If the forecast shows that surplus energy will be available in the future, then the EV charging can be delayed, and the coming surplus energy can be used for EV charging. However, limits must be set for how long the EV charging can be delayed. In this task, a maximum of 3 hours is set as a limit for the EV charging delay to ensure that the batteries of the EVs are full when they are needed.

The maximum peak power control is based on a maximum power limit. In the control, a predefined maximum power is set, and when it is about to be reached, the battery discharging and the EV charging stop. Immediately after the power has decreased, the EV charging starts again, and the BESS is charged full to wait for the next time when it is needed. If the control cannot keep the power below the set limit, then the limit must be increased. In the initial situation, the power limit set to be as low as possible. Zero can be used as the initial value, but in many cases, a regular base level of hourly consumption exists. The initial limit for the power can be set based on that base level of consumption. The maximum peak power decrease algorithm is introduced and discussed in more detail in [13].

The third control target is to minimize the electricity costs by using a market price-based control. Electricity tariffs often include components that vary over time, e.g., the price is different during daytime and night-time. In the simulations done with the Finnish data, prices used by the energy retailer were used that are based on the short-term electricity market price, i.e., day ahead spot price of electricity, which change hourly. This kind of pricing creates an incentive to shift loads from high-price hours to low-price hours. It can also be profitable to charge the battery during low-price hours and discharge it during the high-price hours. Additionally, since the EV charging start can be delayed, benefits from the low-price periods can be achieved. With the control to increase the rate of self-consumption, it is possible to delay the discharge of stored surplus solar PV energy to the periods when the price of electricity is high. This way, the use of surplus solar PV energy provides higher cost savings. The market price-based control leans on the charging optimization, and its fundamental principles are presented in more detail in [14].

3.6 SOLAR SYSTEM SIZING

Maximal benefits of VRE integration can be achieved when the components, i.e., electrical ERs, are sized and operated optimally. Sizing of a solar PV system can be done by utilizing simulations with different production system sizes and finding out the highest profitability from those options. Thus, the sizing of a solar PV system plays a key role in this task. The impacts of different factors, e.g., electricity tariffs and flexibles ERs, are accounted for when optimally sizing the solar PV system. With this method, it is possible to evaluate the impacts of different factors on the VRE integration in multi-apartment buildings.

An example of how the solar PV system sizing can be done by utilizing simulations is shown in Fig. 14. The simulated annual cost savings are for one multi-apartment building over three years (2014-2016) with different solar PV system sizes. The simulated annual cost savings are simulated in 2 kWp steps with respect to the solar PV system size. It is observed from the figure that the annual cost savings increase in a nearly linear fashion with respect to the solar PV system size until a point is reached, where the savings increase with a smaller slope. After that turning point, the savings still increase in a nearly linear fashion. For these two parts, before and after the turning point, lines (i.e., lines A and B shown in Fig. xx.) can be fitted by using linear regression. The intersection of lines A and B represents the optimal solar PV system size, i.e., the point where the difference between the cost savings and the solar PV system costs is the highest. The two parts depicted with line A and B can be interpreted differently. Line A would represent a situation where most of the produced energy is self-consumed. Line B would represent a situation where most of the produced energy is fed to the electricity network, however, the load profile of the customer and the electricity tariffs affect the situation. The fundamental principles of sizing a solar PV system are described in more detail in [2].

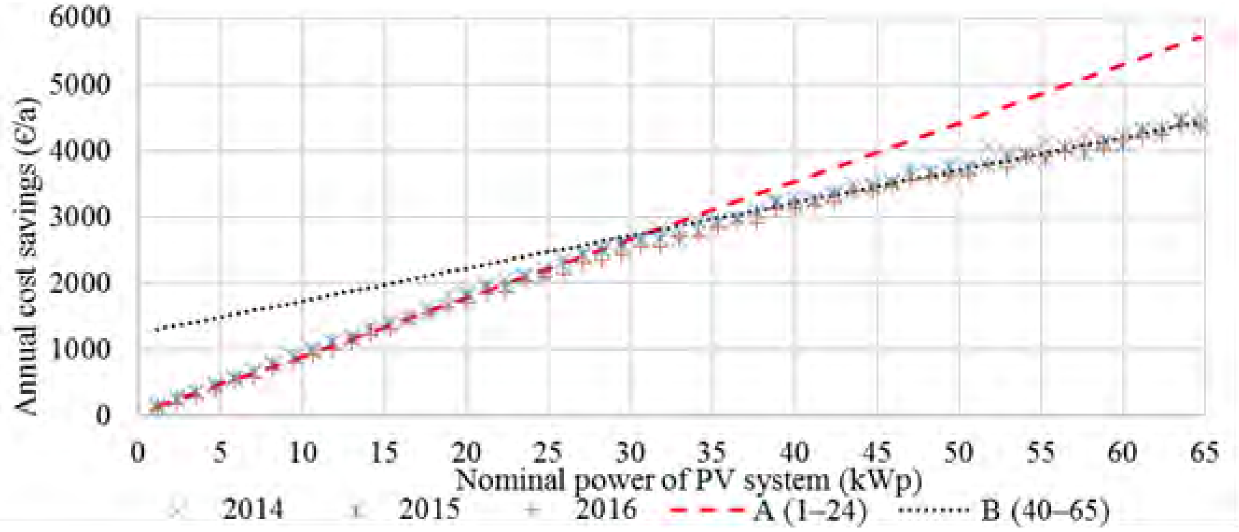

Figure 14: Example of PV system sizing [2]

3.7 SIMULATION CASES

Several ERs that affect the economic benefits either individually or together were studied in the simulations. In the simulations, two flexible electrical ERs, BESS and EV charging control, were included, which are used primarily to increase the solar PV self-consumption rate. Additionally, there are two secondary control targets: market price-based control and peak-shaving control. These four items formed 12 different combinations for the study. In addition, the base case, in which no controls were included, was simulated.

The possible combinations of different simulations are shown in Table 7. The simulation cases were studied in both the original situation, in which the electrical ERs were used only for the common loads of the multi-apartment building, and in the EC model situation, in which the electrical ERs can be used for the apartment loads. The number of different combinations for the simulations and the optimization of the solar PV system size is 26. In terms of electricity tariffs, because distribution tariffs from 9 different Finnish DSOs were used together with three different alternatives for the demand charge, this results in 27 different cases to study with the Finnish data. In total, the number of different simulation case done with the Finnish data is thus 702. For the optimization of the solar PV system size, several system sizes must be studied. Typically, the sizes range from 0 kWp to 60 kWp in 2 kWp steps, which means that the typical number of simulations for sizing the solar PV system is 31. If abnormalities are detected during the sizing process, even more simulations may be required. All the simulations done with the Finnish data are from a period of three years, which means 26,304 data points when the time resolution is one hour. In the Geneva demo case, simulation cases 1 and 6 (see Table 7) were used. The time resolution of the Swiss case study was 15 minutes, and thus, for one year period, the number of data points was 35,040.

Table 7: Combinations of ERs and used control targets in different simulation cases. Green box means that the simulation case is included and red box means that the simulation case is not included.

Factors to optimize	Simulation case #												
	1	2	3	4	5	6	7	8	9	10	11	12	13
EV charging control	🟥	🟩	🟩	🟩	🟩	🟥	🟥	🟥	🟥	🟩	🟩	🟩	🟩
BESS	🟥	🟥	🟥	🟥	🟥	🟩	🟩	🟩	🟩	🟩	🟩	🟩	🟩
Market price-based control	🟥	🟥	🟩	🟩	🟥	🟥	🟩	🟩	🟥	🟥	🟩	🟩	🟥
Peak shaving control	🟥	🟥	🟥	🟩	🟩	🟥	🟥	🟩	🟩	🟥	🟥	🟩	🟩

4. SIMULATION RESULTS

In this section, the results of the simulations and the impacts of different factors to VRE integration are presented. The simulations were made mainly by using the data from Finland to introduce the methods and how they can be used. Different factors, e.g., tariffs, and load and production profiles, vary between different countries. The results achieved with the Finnish data provides rough estimates of the economic impacts in the European environment. In addition to the results of the Finnish case study, results of the simulations made with the Geneva demo case data are also presented in this section. Simulations were made for several different cases that are presented in Section 3.7. From that large number of cases, the most important ones were selected for this section. If a variable that does not impact the results was identified, average values were used to describe the results of those cases.

4.1 ENERGY COMMUNITY CALCULATIONS

Forming an EC affects the electricity costs and the metering as presented in Section 3.1. The results of a PV system optimization in the original case, where the EC model is not used (blue bars), and in the case where the EC model is used (orange bars) are presented in Fig. 15. The figure shows the different cases for when (1) no controls were used, (2) EV charging control was used, (3) BESS was used, and (4) both EV charging control and BESS were used. In those different cases, flexible resources were used to increase the self-consumption rate of solar PV production. It is observed from Fig. 15 that the forming of an EC significantly increases the optimal size of a solar PV system. The results depict the average values of all the 6 multi-apartment buildings of the Finnish case study with the tariffs shown in Section 2.2. In the results, there is variation between the multi-apartment buildings and different DSOs. However, the average values show that the EC model enables us to size the solar PV system to a much larger one compared to the original case, which depicts the practice of today. The average difference in the solar PV system size is approximately 10.4 kWp, which means a considerable increase of 46% in the optimal solar PV system size.

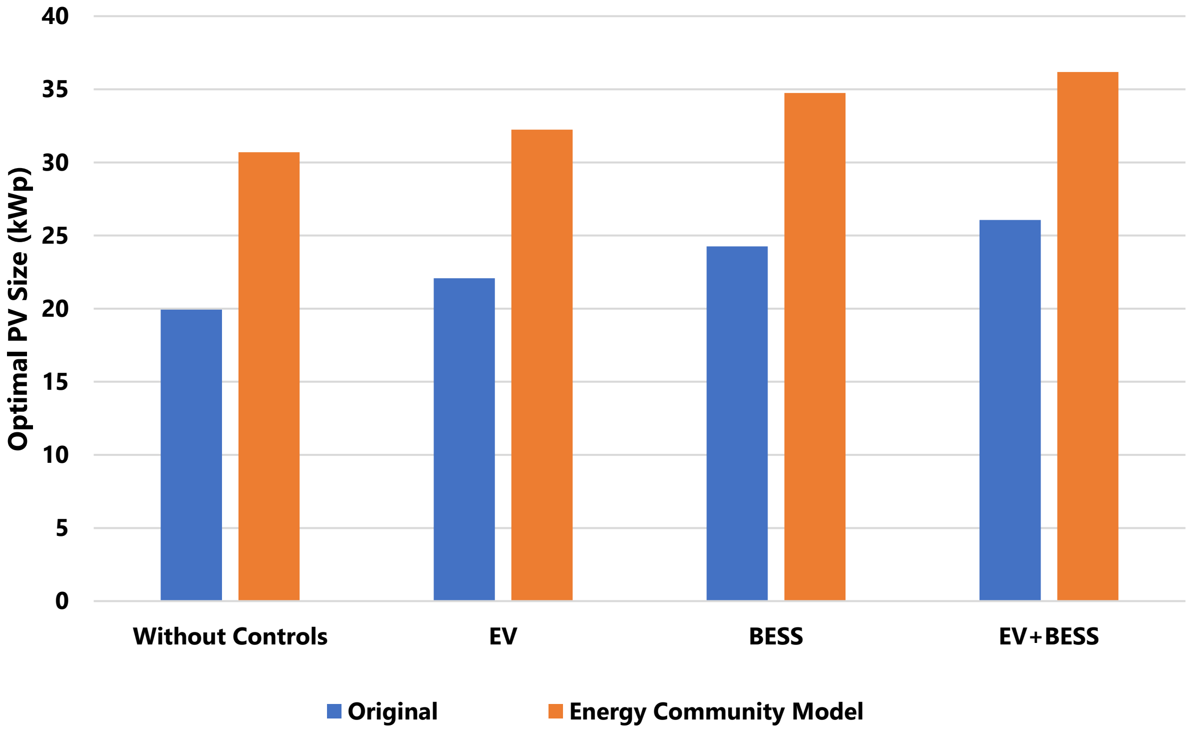

Figure 15: Impact of forming energy community to PV sizing

The differences between the original case and the EC model cases are quite similar in all the cases with different flexible ERs. However, there are some differences, and those differences in the results between different flexibility ERs are studied and analyzed in more detail in Sections 4.2 and 4.3. The annual cost savings that a multi-apartment building could achieve by investing in an optimally sized solar PV system in different situations are presented in Fig. 16. By comparing the bars shown in Figs. 15 and 16, it is observed that the cost savings follow the rises in the optimal sizes of the solar PV system in different cases. This would mean that the overall profit would remain almost the same. If the profits are the same, then it does not matter much what control system, or a measurement system, is used from a multi-apartment owner or resident perspective.

In the long term, higher annual cost savings accumulate higher profits, and thus, investing in a larger optimally sized solar PV system is profitable. As observed from Fig. 16, higher annual cost savings can be reached with the EC model and the use of flexible ERs.

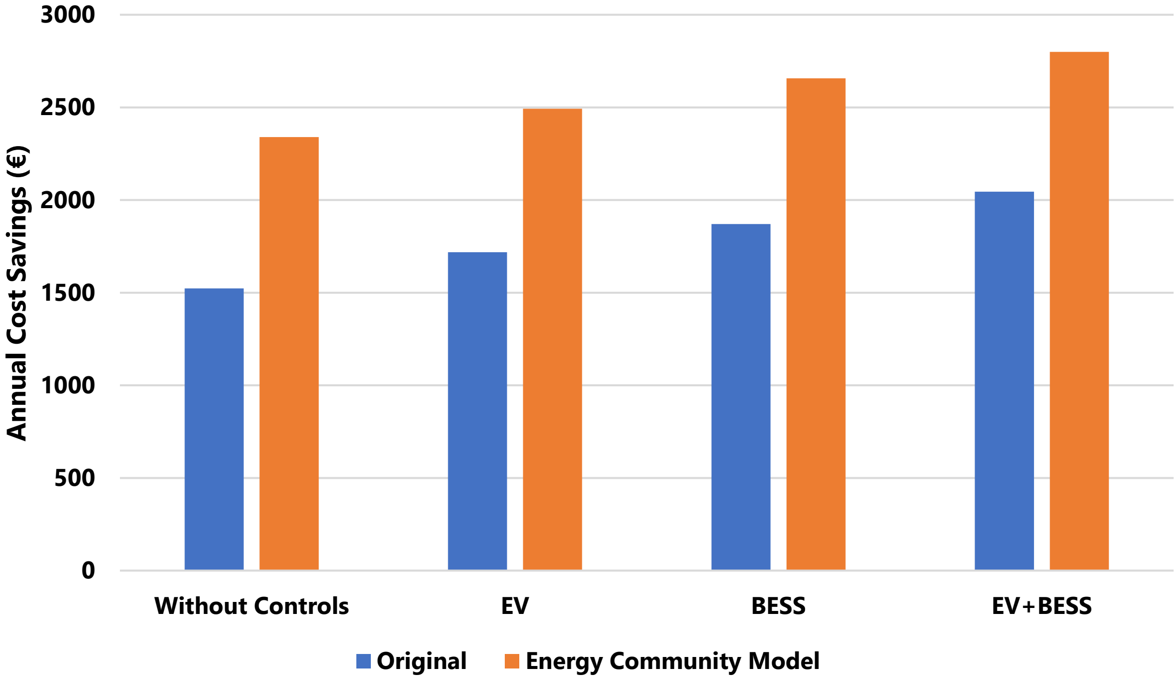

Figure 16: Impact of forming energy community to annual cost savings with optimal PV size

The optimal sizing of a solar PV system, i.e., in the simulations made without any controls, for the six different multi-apartment buildings situated in Finland is shown in Fig. 17. From the figure, it can be observed how large an impact the load profile of the multi-apartment building has on the optimal solar PV system size. In the figure, the variation of the curve depicts the results of the simulations made with the tariffs of 9 DSOs and the 3 different billing options for the demand charge. It is observed from the results that there are buildings where the EC model does not lead to significant increase in the solar PV system size, whereas, in some buildings, the impact is very high. For instance, in building 2, the EC model increases the optimal size of the solar PV system size by approximately 50%, and, in building 4, the increase is even as high as 200%.

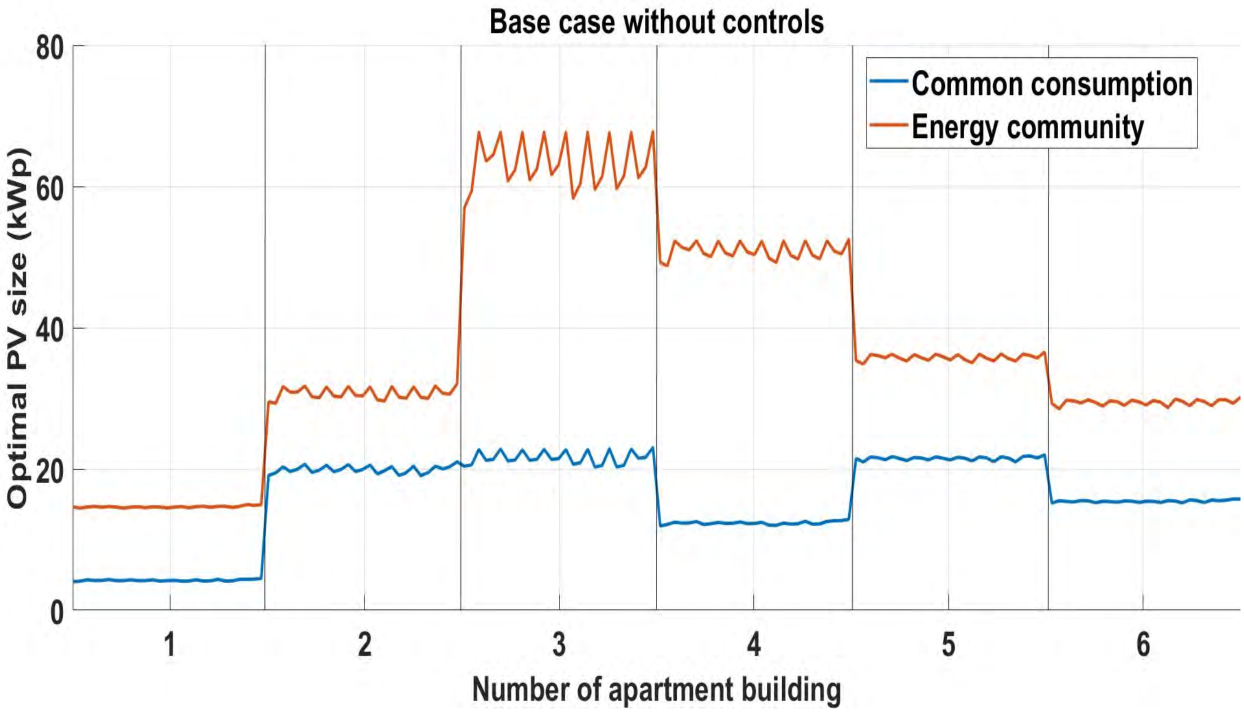

Figure 17: PV system optimal sizing for apartment buildings with different tariffs

4.2 IMPACTS OF TARIFFS

The sizing of a solar PV system is affected by several factors. For instance, the load profile of the target location has the strongest impact, but the tariffs also affect the sizing that is based on the optimization of economic benefits. The average values of the optimized solar PV system sizes in all the cases with 9 different DSO tariffs are shown in Fig. 18. The difference between the largest and smallest optimal solar PV system size is under 1 kWp. There are 2 DSOs (DSOs 2 and 9) whose tariffs lead to a larger solar PV system size compared to the others, and, in the case of two DSOs (1 and 6), the tariffs lead to a smaller solar PV system size compared to other DSOs. By taking a closer look at the tariffs, DSOs 2 and 9 have the lowest demand charges in relation to the volumetric charge, and the opposite situation occurs in the tariffs of DSOs 1 and 6. Even if the impact is low, as the weight of the demand charge increases, it decreases the optimal size of the solar PV system. The annual electricity costs in those same cases are shown in Fig. 19. It is observed that the level of the pricing does not affect the sizing of a solar PV system. DSOs 1 and 9 represent the two extremes with respect to the sizing of the solar PV system, but still, the average annual electricity costs are of the same magnitude.

Thus, the price levels affect the profitability of the solar PV system investment but not straightforwardly the sizing of it. In the sizing of a solar PV system, there is a gap around the intersection of the linear regression line (see Section 3.6), from where the optimal system size can be found. Lower price levels mean that the optimal system size can be found from the lower part of that gap and vice versa. Still, the impact of the ratio between the tariff components on sizing of the system is stronger than the impact of the price levels. There are two DSOs (2 and 9) whose tariffs lead to a higher solar PV system size compared to others, and two DSOs (1 and 6), whose tariffs lead to a smaller system size compared to others.

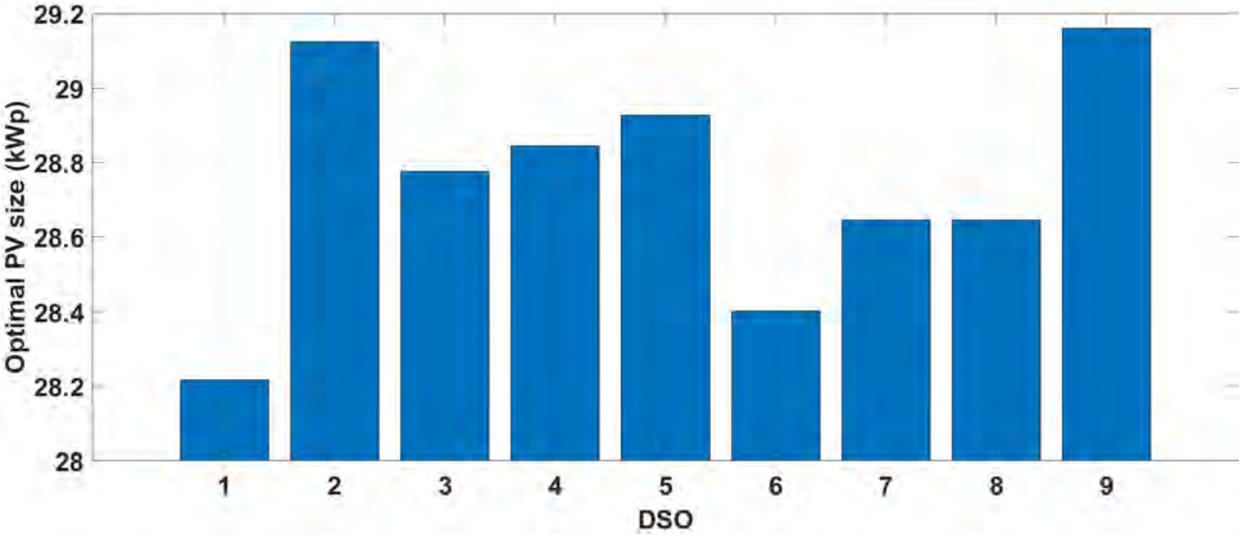

Figure 18: Average value of optimal PV sizes from all cases with the tariffs from 9 DSO

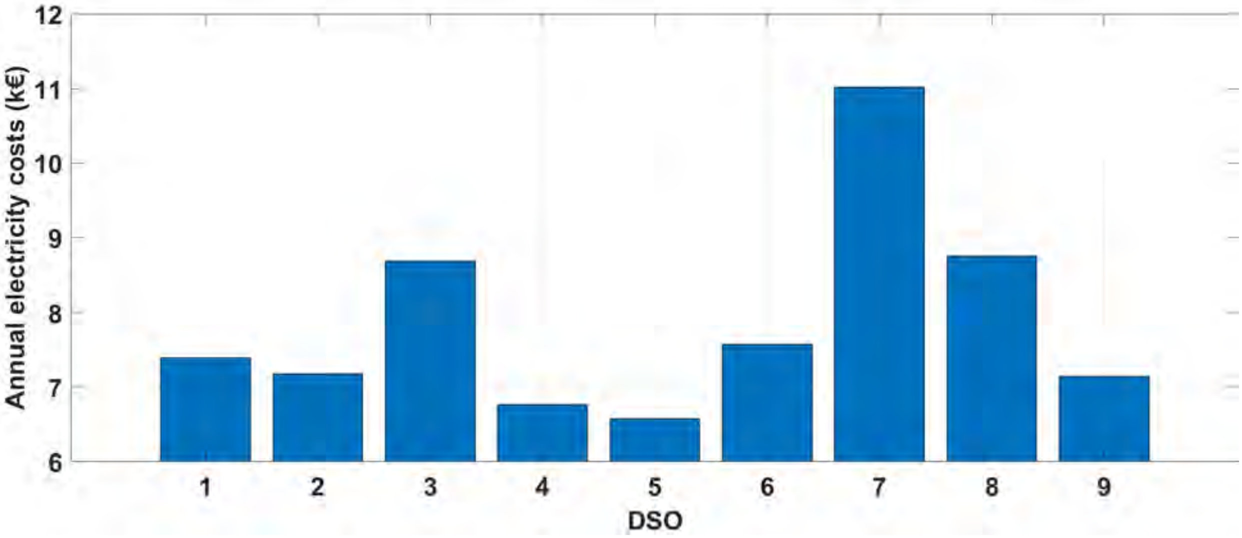

Figure 19: Average value of annual electricity costs in all cases by using tariffs from 9 DSO

Another variable that was studied in the simulations was the billing basis of the demand charge used in the electricity distribution tariffs. In the simulations, three different billing bases were studied, i.e., the harmonized demand charges presented in Section 2.1, which were (1) monthly peak demand, (2) the average of 3 highest demands of each month, and (3) the moving peak demand from a 12-month interval. The impacts of the billing basis of the demand charge in those three cases are presented in Fix. 20. It is observed from the figure that the optimal size of the solar PV system is quite similar in cases (1) and (2). However, when the billing basis is the moving average from a 12-month period, the optimal size of the system is approximately 1 kWp higher than in the other two cases. By comparing Figs. 18 and 20, it is observed that the impact of the billing basis on the optimal solar PV system size is more significant than the impact of the ratio of the different tariff. The average annual electricity costs in the three billing demand cases are shown in Fig. 21. From the figure, it is observed that the differences are small, however, when the billing basis is the monthly peak demand, it leads to the higher average annual electricity costs when compared to the other two cases. It is highlighted that the harmonized demand charges are determined based on the annual turnovers in the original case, where no controls are used, so that the total turnover for the DSO remains unchanged. The results show that when the billing basis of the demand charge is the highest demand of the month, it leads to higher electricity costs for the customer in cases where ERs and controls are used.

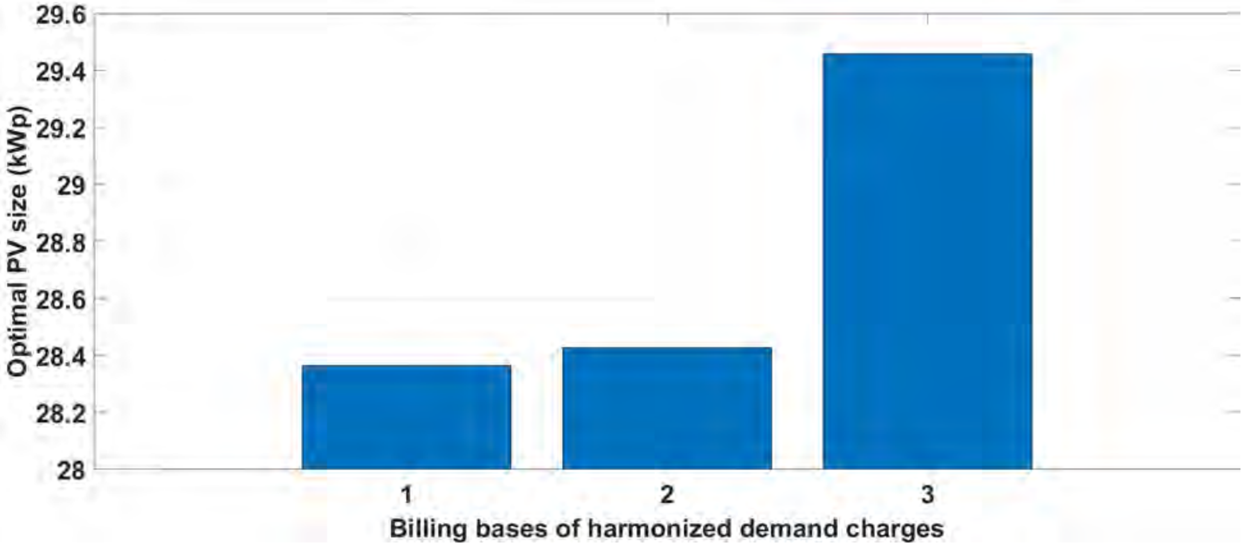

Figure 20: Average value of optimal PV sizes in all cases by using three different billing bases of harmonized demand charges. 1: Monthly peak demand, 2: The average of 3 highest demands of the month 3: Moving peak demand from a 12-month interval.

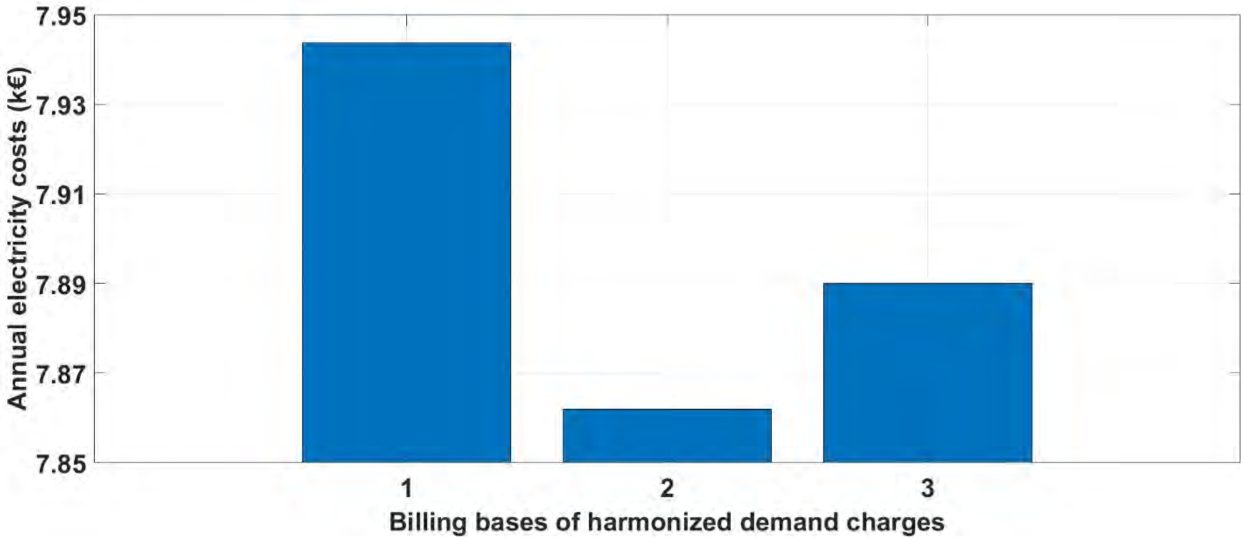

Figure 21: Average value of annual electricity costs in all cases by using three different billing bases of harmonized demand charges. 1: Monthly peak demand, 2: The average of 3 highest demands of the month 3: Moving peak demand from a 12-month interval.

For the Geneva demo case, the optimal solar PV system size can be determined based on the measured consumption and production data. The measured production for a 21 kWp solar PV system was scaled for system sizes ranging from 0 to 60 kWp with 2 kWp intervals. The results of the optimal sizing are shown in Fig. 22. It is observed from the figure that the optimal system size for the Geneva demo case is approximately 12 kWp without BESS, which results in approximately 4,000€ in terms of annual cost savings. The feed-in tariff for the surplus solar PV energy is high (0.155 c/kWh), which makes it possible to size the system to be larger. However, the profitability decreases when the system size is larger than 12 kWp. The feed-in tariff currently in place is high as a response to the ongoing energy crisis (situation in 2023), and the magnitude of the feed-in tariff is expected to decrease in the future. In the simulations, another case was studied where the feed-in tariff was set to 0 c/kWh to investigate the impacts of the feed-in tariff on the solar PV system sizing, and the results of those simulations are presented in Fig. 23. It is observed from the figure that the change of the feed-in tariff magnitude does not affect the lower linear regression line. However, the slope of the upper linear regression line changes dramatically, which moves the intersection of the regression lines to the right. The gap between the intersection and the simulated points increases, which means that the gap, in which the optimal system size can be found, becomes wider, and the optimal system size is similar to the previous case. The magnitude of the feed-in tariff affects when the solar PV system is oversized. When the magnitude of the feed-in tariff is small, the profitability of the system decreases significantly if the system is oversized.

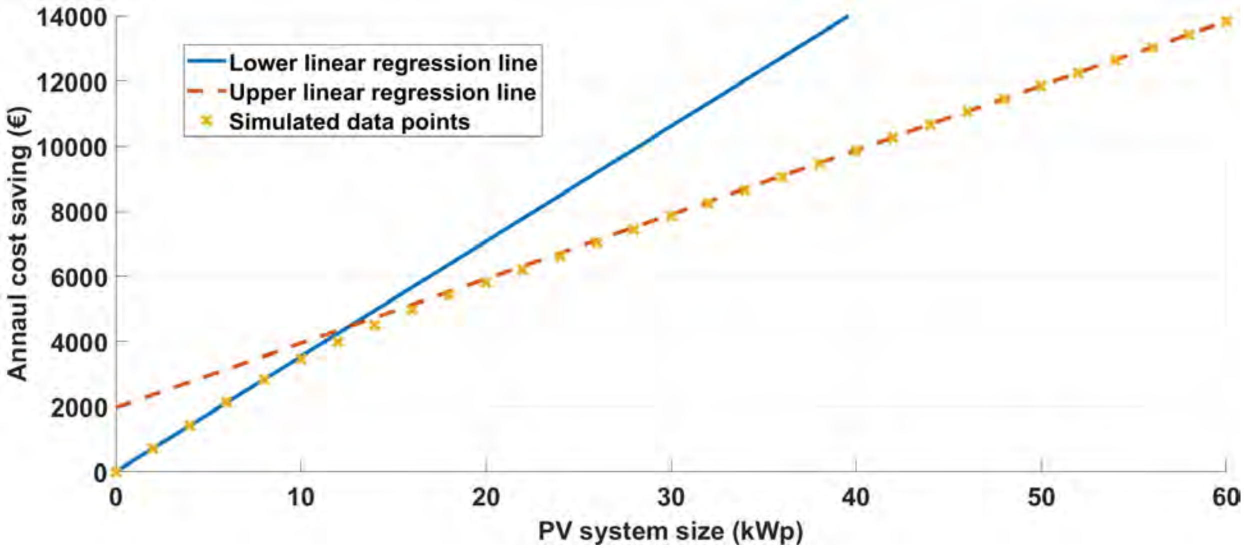

Figure 22: PV size optimization for Geneva demo case without battery (surplus PV energy feed-in tariff is 0.155 c/kWh)

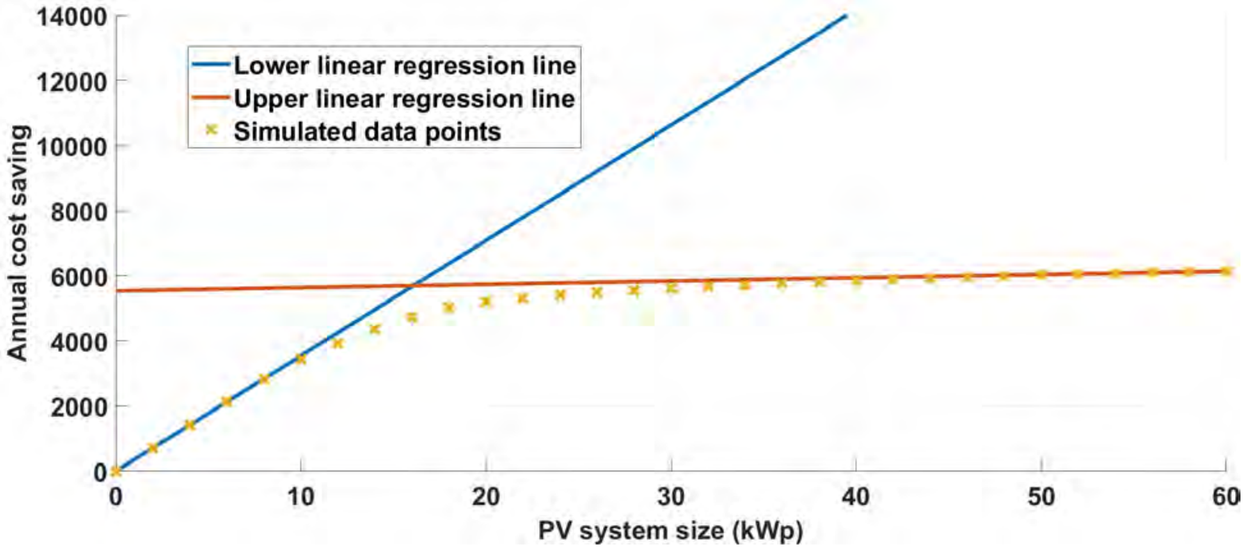

Figure 23: PV size optimization for Geneva demo case without battery, but in case when surplus PV energy feed-in tariff is zero

4.3 IMPACTS OF BATTERY STORAGE SYSTEM

To execute several control targets, a BESS can be used as a tool in a multi-apartment building. In the simulations, three different control targets were investigated:

(1) increasing the self-consumption rate (SC),
(2) market price-based control (MPC), and
(3) peak-shaving control (PSC).

The impacts of using a BESS with different controls on the sizing of the solar PV system in a situation, where the ERs are used only for the common consumption of the building are shown in Fig. 24. The impacts on the sizing in a situation where the EC model is used are shown in Fig. 25. It is observed that in both cases, the differences between the impacts of different control targets used are not that significant.

However, the use of the EC model strongly affects the overall situation as, with the use of a 20 kWh BESS, the optimal size of the solar PV system increases by approximately 25.6 kWp as opposed to approximately 4 kWp, which is the case when the ERs are used only for the common consumption of the building.

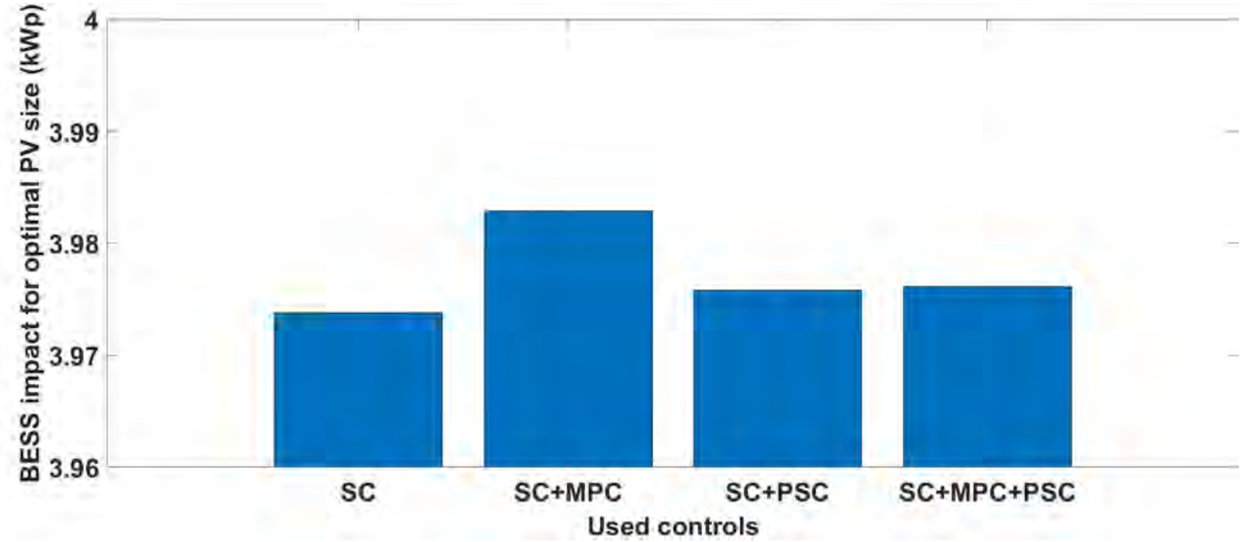

Figure 24: Impact of using BESS for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy resources is used only for common consumption of apartment building

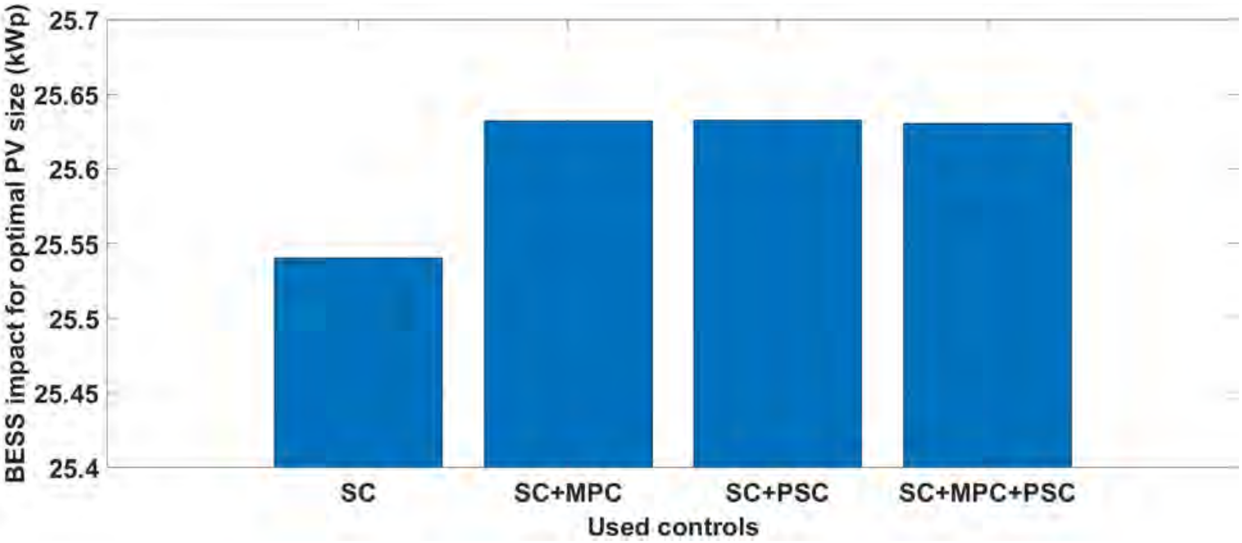

Figure 25: Impact of using BESS for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy community model is used

In the Geneva demo case, there is a 20 kWh BESS, which increases the solar PV self-consumption rate. The control system in the demo case system was programmed by the manufacturer, and the exact control algorithm of the system is not known. However, the fundamental principles of the control system operation can be modelled by investigating technical information that is made available by the manufacturer and the measurements from the consumption, solar PV production, and battery discharging. From the measured data, a C-rate of approximately 0.23 can be evaluated for the battery, which means a maximum power of

5 kW. The battery control algorithm seems to be based on charging the battery with the available energy produced with the solar PV system whenever possible and using that energy later, e.g., during the evening. This way of control means that a lot of charging-discharging roundtrips are made and that causes losses. The calculations show that the use of a BESS is not profitable with the present control system, i.e., the solar PV system is more profitable without the BESS. The control system presented in this deliverable is much simpler and based only on charging the surplus solar energy to the battery, which is used immediately when it is possible. With this simpler control algorithm, it is possible to use the BESS so that additional cost savings are achieved compared to those savings achieved just with the solar PV system.

The sizing of the solar PV system for the Geneva demo case simulations that include a BESS is shown in Fig. 26. The BESS in this case has no significant impact on the sizing of the solar PV system. It is observed from Fig. 26 that the area from which the optimal solar PV system size can be found is wider with the BESS than without it. From the simulated data points, two turning points can be located. The first turning point occurs between the values 6 and 8 kWp, and the second turning point occurs when the value is approximately 20 kWp. Thus, it is difficult to use the typical sizing method, which provides a value that is between those two turning points. This abnormal behavior is caused by the tariffs, and the phenomenon is discussed in more detail later in this section. By comparing Figs. 22 and 26, it is observed that the solar PV system together with a BESS provides just slightly higher annual cost savings than if a solar PV system is used without BESS. The differences in the cost savings in those two cases are shown in Fig. 27. It is observed that the differences in savings are low when the size of the solar PV system is small. However, as the size of the solar PV system increases, the impact of a BESS on the difference in savings becomes more significant.

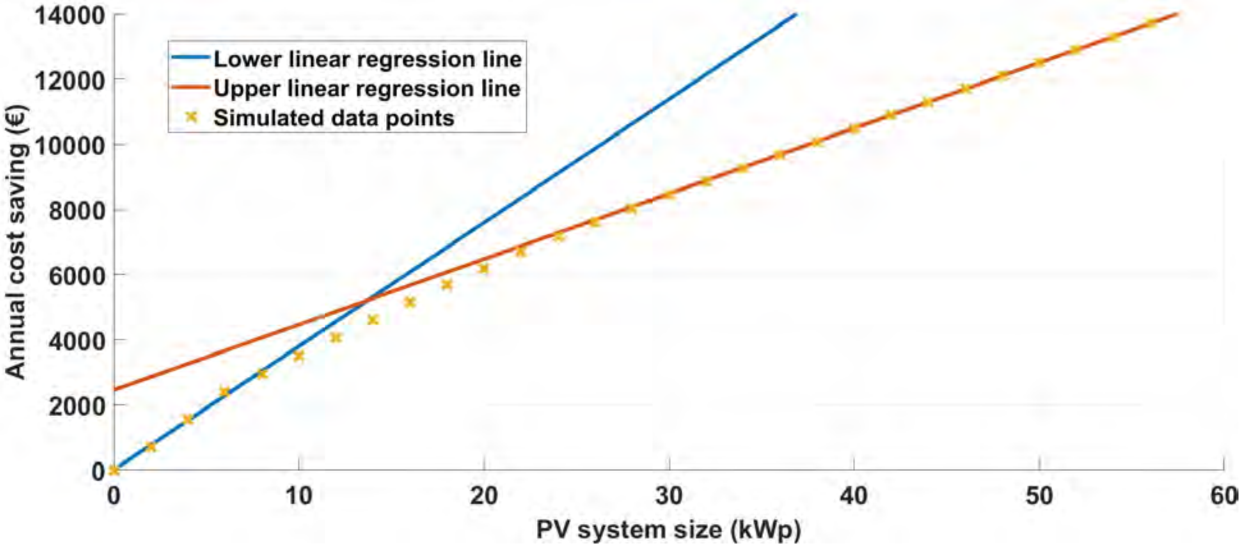

Figure 26: PV size optimization for Geneva demo case with BESS

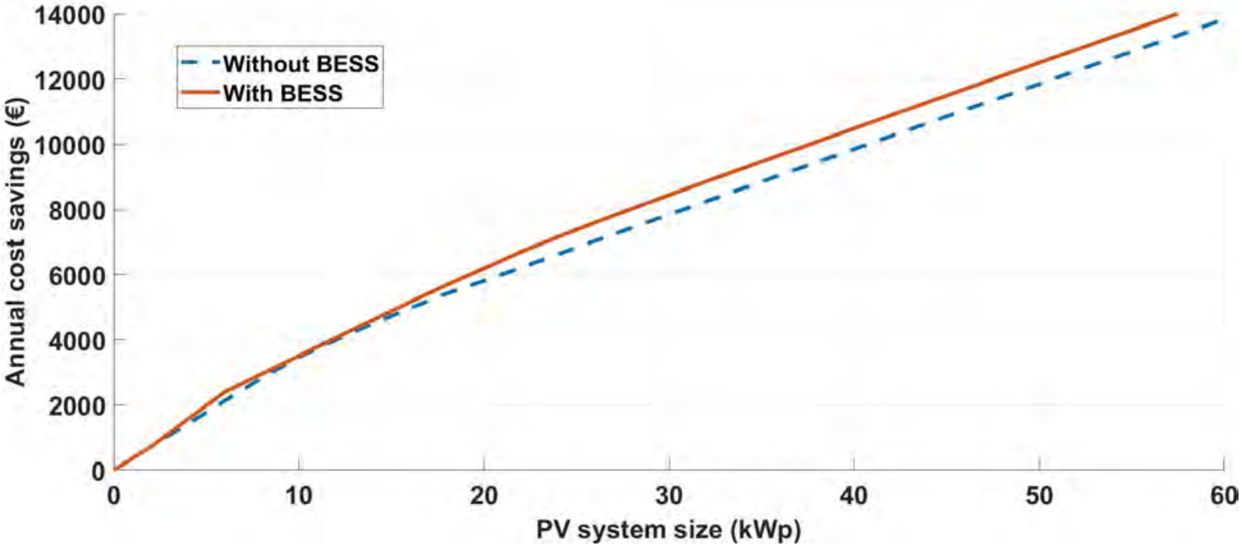

Figure 27: Annual cost savings in Geneva demo case by using different size of PV systems with and without BESS

The annual cost savings vary with small solar PV system sizes with a BESS as shown by the difference between the curves depicted in Fig. 27. In addition to the impacts of solar PV systems of different sizes, the differences in the annual cost savings achieved with different BESS sizes can be investigated as well, and those differences are shown in Fig. 28. The differences in the cost savings were modelled for three different BESS sizes. The first size is 21 kWh, which is the size of the BESS in the Geneva demo case. The second and the third sizes, i.e., 4 kWh, and 10 kWh, are smaller, however, those BESS include similar technical features to the Geneva demo case. The comparison between the three BESS options explains the abnormal behavior in the sizing of the solar PV system. As observed from the figure, a local peak is reached when the size of the solar PV system is 6 kWp and the annual cost savings are 267€, and those values are the same for all three sizes of the BESS. After this, the annual cost savings decrease until the size of the solar PV system reaches 10 kWp and the annual cost savings are only approximately 36€. The variation in the annual cost savings at that point is approximately 2€ between the three BESS sizes. From that point onward, the cost savings increase with the size of the solar PV system, and the difference in the annual cost savings starts to show. With a 4 kWh BESS, the cost savings start to level out to approximately 300€ when the size of the solar PV system reaches 20 kWp. With a 10 kWh BESS, the savings are approximately 400€ after the size of the solar PV system reaches 24 kWh. Lastly, with a 20 kWh BESS, the savings are approximately 600€ after the size of the solar PV system reaches 28 kWp.

The results of this study show that in the Geneva demo case, where a 21 kWp solar PV system and a 20 kWh BESS are installed, the theoretical annual cost savings are only approximately 100€ higher than what could be reached with a 4 kWh BESS. If the size of the solar PV system was to increase to 30 kWp, the difference in savings would be approximately 300€. In that case, the profitability of a smaller BESS would be higher when the investments costs are compared to the annual cost savings. The use of a BESS significantly decreases the costs that ensue from the demand charges when compared to the case where BESS is not used and the size of the solar PV system is in the range of 4-8 kWp, or larger than 22 kWp. With sizes that are in the range of 10-20 kWp, the BESS does not provide any extra benefits for decreasing the maximum demand. The cause for this phenomenon is in the load profile in the Geneva demo case. The results indicate that the ratio between the solar PV system size and the size of the BESS is not optimal, albeit the load profile is well-suited for the solar PV production profile. Thus, from an economic perspective, the Geneva demo case is not the best in the case of BESS. In the electricity tariff, the demand charge is relatively high, and the use of a smarter, compared to the one used at present, control system for peak-shaving could provide higher profitability for the BESS.

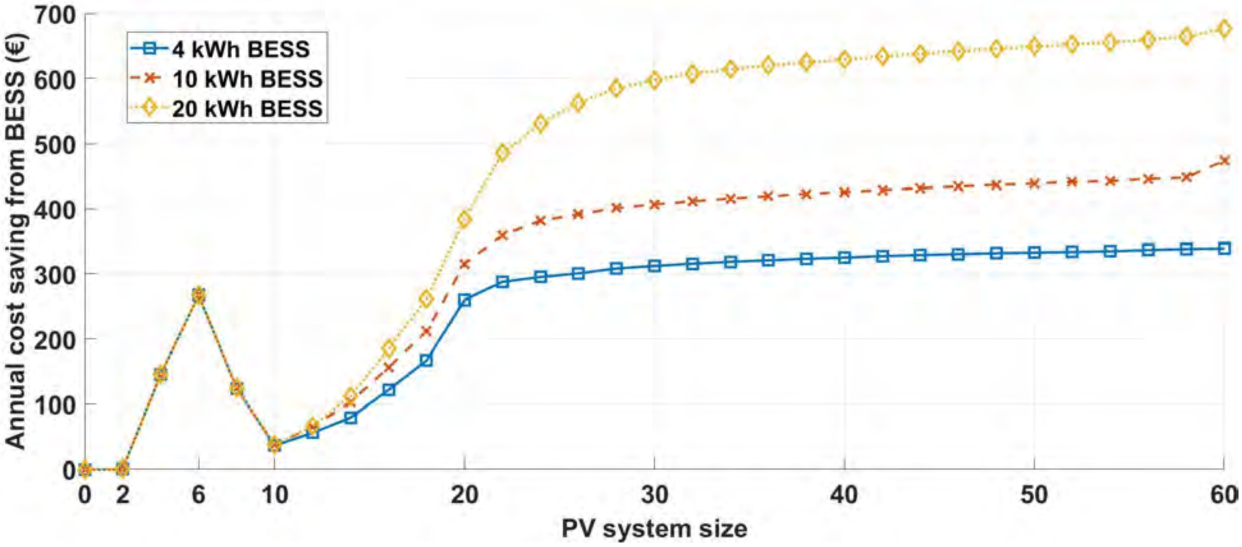

Figure 28: Annual cost saving from BESS (in addition to PV) in Geneva demo case with different PV sizes and three sizes of BESS

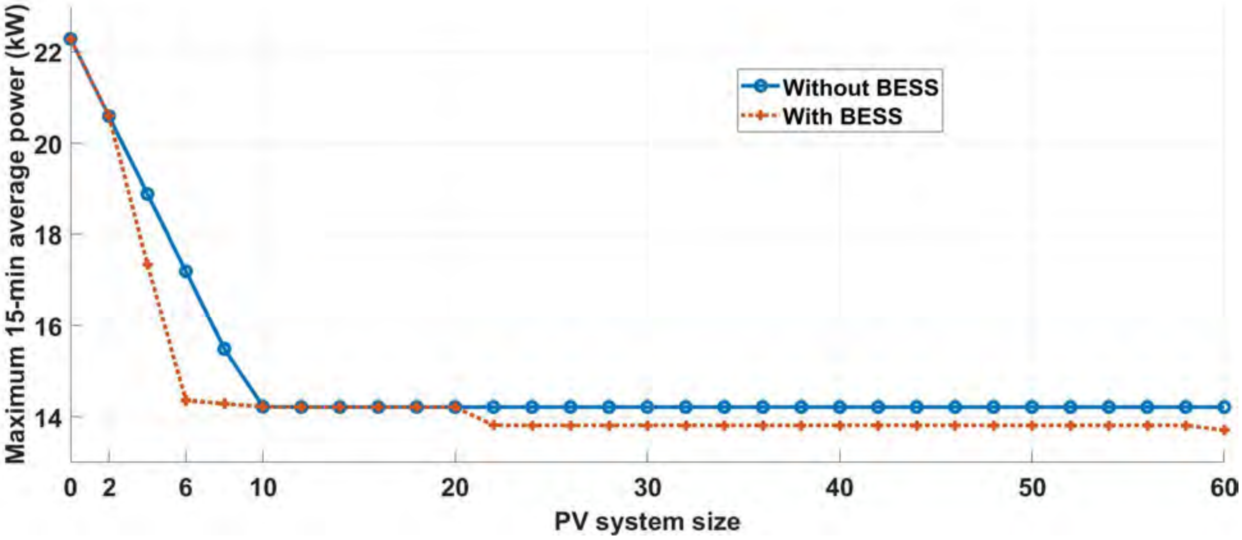

Figure 29: Impact of PV system size for maximum 15-minute average power in Geneva demo case with and without BESS

4.4 IMPACTS OF ELECTRIC VEHICLE CHARGING CONTROL

The EV charging control enables the shifting of loads so that the load profile matches the solar PV production profile as well as possible, which means that the EV charging can be scheduled to happen during times when surplus of solar energy is available. In this study, EV charging control was simulated with the Finnish data, and similar control targets to those used for the BESS presented earlier were used. The results of the simulations in the situation where the ERs are used only for the common consumption of the multi-apartment building are shown in Fig. 30, and the results in a situation where the EC model was used are shown in Fig. 31. It is observed from those figures that the increase in the optimal size of the solar PV system due to the impact of EV charging control is approximately 2.2 kWp when the ERs were used only for the common consumption of the building, and 23.0 kWp when the EC model was used. Thus, the impact of using the EC model on the solar PV system size is significant when EV charging control is utilized. The selection of the control target, on the other hand, does not have a significant impact on the solar PV system size (approximately 0.1 kWp difference at most). The use of several control targets simultaneously resulted in only a slightly larger optimal solar PV system size when compared to the situation where the target was to increase the self-consumption rate. The results shown in Figs. 30 and 31 represent the average values of all studied cases. Between individual cases, the variation can be high, but the average values provide a broader view of the impacts.

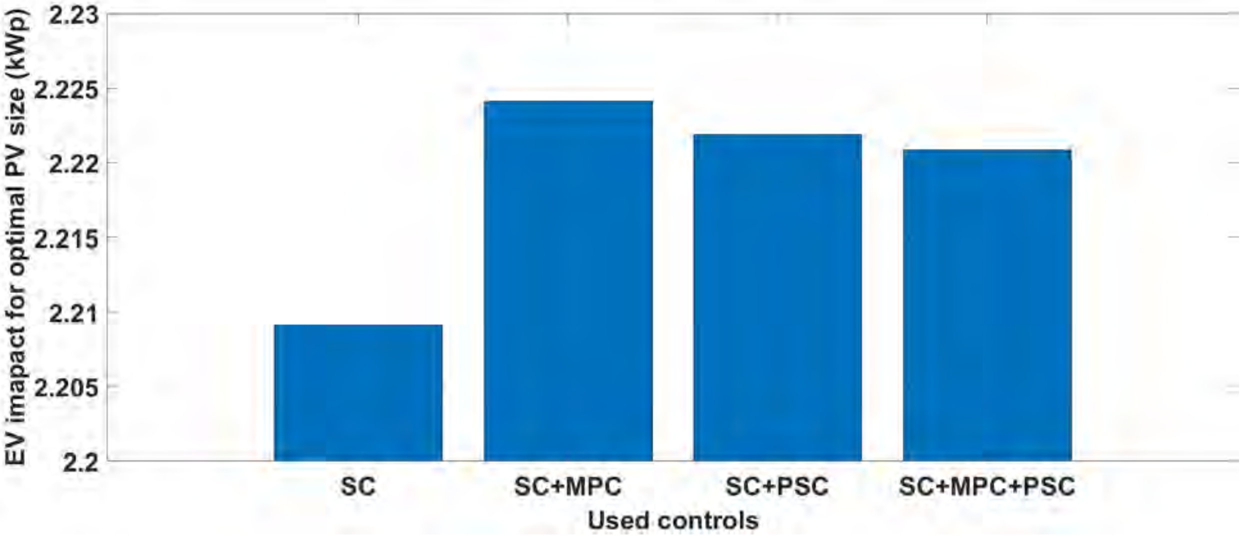

Figure 30: Impact of using EV charging control for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy resources is used only for common consumption of apartment building

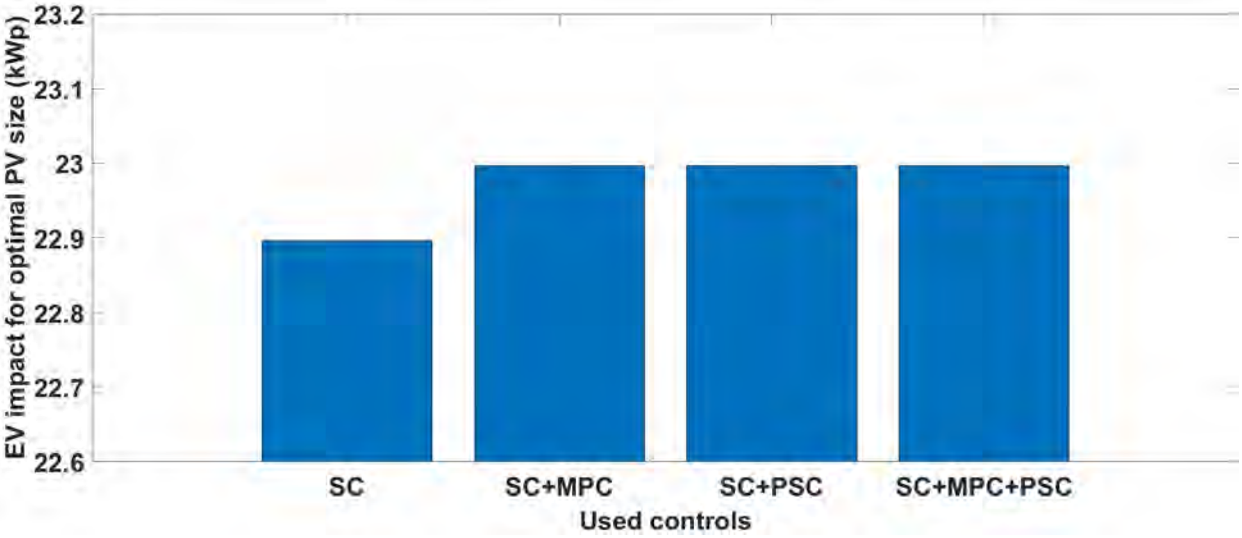

Figure 31: Impact of using EV charging control for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy community model is used

4.5 COMBINED CONTROLS

Both flexible ERs (BESS and EV charging control) can be used simultaneously in a multi-apartment building. When the combined control (CC) of those resources is used in a situation where the ERs are used only for the common consumption of the building, the impact of the CC on the sizing of the solar PV system is shown in Fig. 32. It can be observed that the impacts of CC are almost equal to the sums reached when the ERs are used separately. This can be observed by comparing Figs. 24, 30, and 32. This means that individual ERs, i.e., BESS and EV charging, do not weaken the potential of one another. The use of several control targets simultaneously results in only a slightly more significant impact than when the control target is to increase the self-consumption rate. The results of the case where the CC is used in the EC model are shown in Fig. 33. It is observed from the figure that the impact is more significant than the individual impacts of either BESS (see Fig. 25.) or EV charging control (see Fig. 31.), but still the differences are relatively small. This means that there is only limited potential to increase the optimal size of the solar PV system by using flexible ERs in the EC model. However, the full potential cannot be reached by using the ERs individually, but together, they can provide even more flexibility than what is needed.

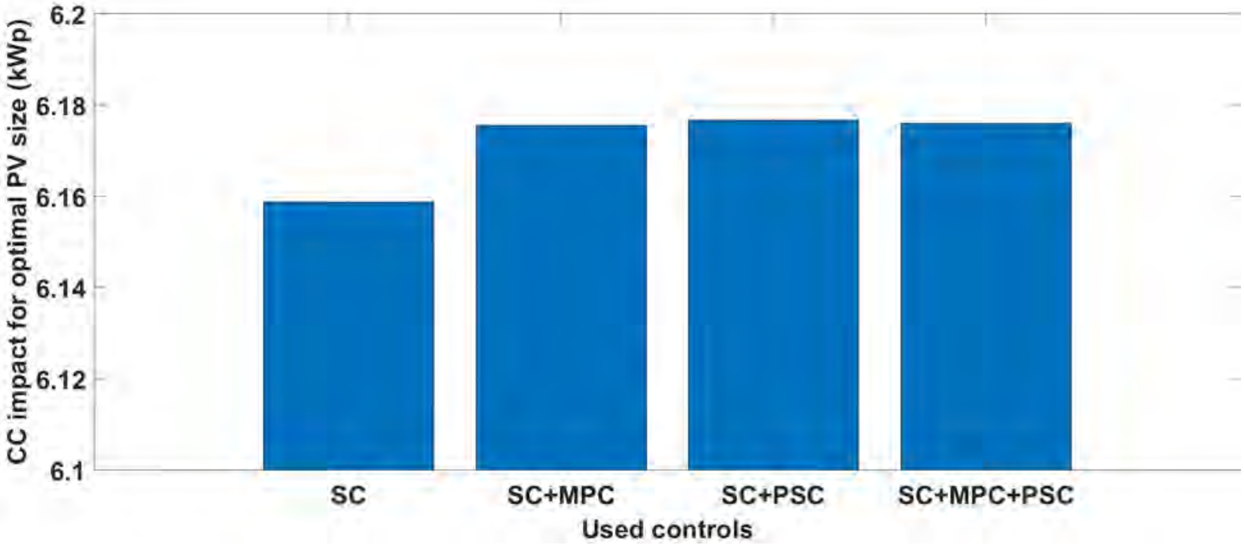

Figure 32: Impact of using combined control (CC) with BESS and EV charging control for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy resources is used only for common consumption of apartment building

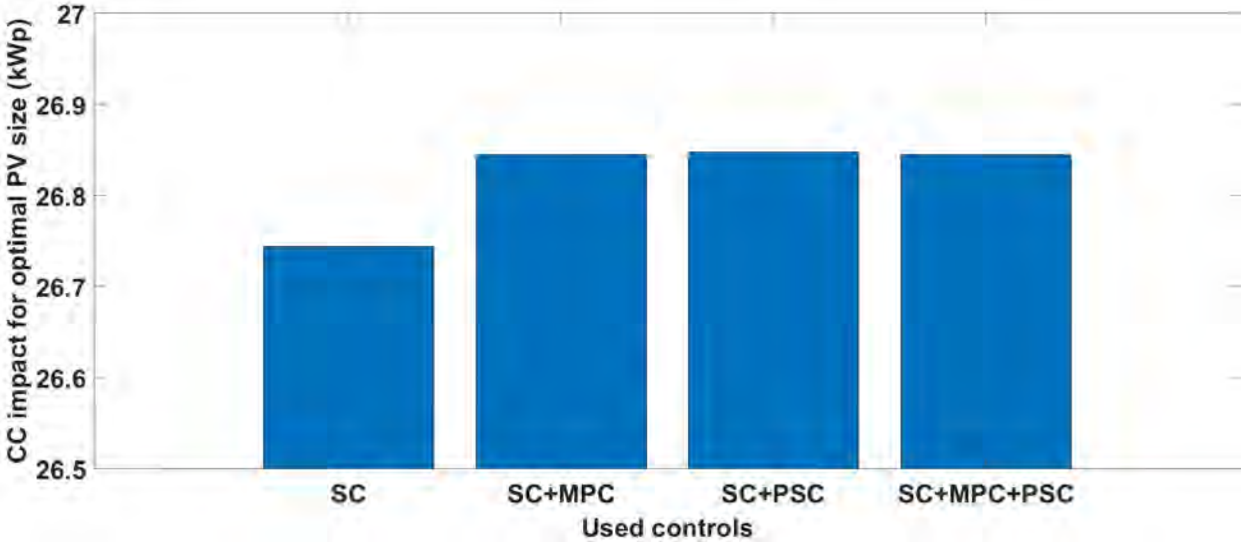

Figure 33: Impact of using combined control (CC) with BESS and EV charging control for PV sizing with different control targets: increasing self-consumption (SC), market price-based control (MPC) and peak saving control (PSC), when energy community model is used

5. CONCLUSIONS

The integration of variable renewable energy (VRE) in multi-apartment buildings is affected by several factors. For instance, from an apartment owner or resident perspective, investments made in VRE should be profitable and maximum economic benefits are typically expected. Today, solar photovoltaic (PV) energy production is popular, and it is well-suited as a VRE production method in multi-apartment buildings. However, the sizing of a solar PV system plays a key role in seeking economic benefits, i.e., profit maximization. The sizing is affected by different factors, e.g., the load and production profiles, electricity tariffs, and what flexible energy resources (ERs) are available. In this deliverable, methods as to how those different factors can be accounted for to study the economic benefits of VRE integration in multi-apartment buildings. The investigations included in the deliverable were made by simulations using actual measured data and existing electricity tariffs.

As for the data requirements to study the economic impacts , consumption data from the studied location, i.e., a multi-apartment building, for at least one year period is required. This applies to existing buildings for which the data is already available. For new buildings, the required data from one year is not available, and thus, typical profiles and figures for buildings of different sizes should be done by using statistical load and production modelling methods that account for different electrical ERs. The interval of the measurement data should be the same as what is used in the billing of electricity. However, if the resolution of the consumption data is higher than what is used in the billing, the data can be interpolated so that the intervals match. Additionally, to study the economic impacts of an energy community (EC) model, the measurements should be available for both the common loads of the building and the apartments. To account for VRE production, such as the solar PV systems used as an example in this task, data about the energy production should be available. For instance, if a solar PV production profile is available either at the studied site, or near it, it can be used in the calculations. Alternatively, if a production profile is not directly available, the profile can be modelled using, e.g., solar irradiance measurements or models, which account for the relevant factors, e.g., the location of the Sun in the sky, based on which theoretical irradiance profile can then be determined. Lastly, the price data, i.e., electricity tariffs, should be accounted for so that the electricity costs can be calculated.

The stable components used in the studies presented in this deliverable are the initial load and production profiles. By using different demand control procedures, which are studied in other tasks of the PRELUDE project (e.g., T5.3), it is then possible to modify the load profiles. However, in this task, the initial load profile is invariable. The changes made to the demand, seen from the electricity grid viewpoint, were made by using flexible ERs, such as battery energy storage system (BESS) and electric vehicle charging (EV) control. The BESS enables the modification of the demand profile to minimize the electricity costs. The battery model used in this task has well-known features of batteries that are used in other similar sites, such as residential buildings. The sizing of a BESS should be done based on the load profile of the studied location, and the sizing of the solar PV system can be done after the sizing of a BESS. Another flexible ER is the EV charging control, which is likely to become more important in the future as the number of EVs increases significantly. The potential of EV charging control in VRE integration can be studied when the number of EVs are modelled, and the charging demands of the vehicles are known. In this deliverable, the methods how those items can be determined are based on driving statistics. When the charging needs have been determined, timeslots can then be determined for when the charging could be delayed so that the charging demand can be fulfilled with VRE production, e.g., solar PV production, as efficiently as possible.

In the price data, there can be significant variation in the electricity tariff formats and prices depending on the location of the studied site. However, the tariffs are typically public and available, and thus, the impacts of electricity tariffs can be studied in different areas. For instance, in Finland, the distribution system operators (DSOs) have different ratios between the tariff component, which can impact the sizing of a solar PV system. For instance, the tariffs affect how much VRE can be integrated to a multi-apartment building so that the building or apartment owners receive maximal economic benefits from the use of ERs. Additionally, there are different models as to how the surplus energy fed to the electricity grid is treated.

Several counties have had feed-in tariffs in place, where a fixed rate is paid for the energy fed to the electricity grid. For instance, in Finland, the surplus energy can be sold to the energy retailer at a market price (day ahead hourly spot price of electricity). This kind of arrangement creates incentives to time the grid feeding during the high-price hours.

The results presented in this deliverable are based on simulations, in which the time resolution of the electricity use at an hourly level (Finnish data) or quarter-hourly level (Geneva demo case data). The simulations provide new load profiles that result from using different ERs, and when the solar PV system is optimized based on different factors. The simulations enable the evaluation of the economic benefits provided by different control algorithms. Simply put, based on the simulations, the potential benefits of different components, i.e., the annual cost savings achieved with the solar PV system and the additional benefits reached by using the BESS with different control algorithms, can be quantified. In the Geneva demo case, the present control algorithm of the BESS is made by the manufacturer, which is a commercial actor. The results of the simulations show that the solar PV system, without the use of a BESS, can lead to higher cost savings than with the current setup at the demo site. Additionally, by modifying the used control algorithm, the cost savings, with BESS included, can be significantly higher.

The main result of this deliverable is that by utilizing the EC model, the possibilities to integrate VRE in multi-apartment buildings can increase significantly. The use of ERs also increases the VRE integration potential, but the EC model clearly has stronger impacts compared to the present model. EV charging control can also play a central role in VRE integration in the future, but it cannot provide for the demand for flexibility alone. Even if the number of EVs increases strongly in the future, there is still a need to use BESSs. During the time when there is not yet a significant number of EVs, BESS together with controllable loads play a key role in providing flexibility for the electrical energy system and making it possible to integrate VRE in multi-apartment buildings.

APPENDIX A

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