Applied Energy 361 (2024) 122924

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Techno-economic analysis on optimizing the value of photovoltaic electricity in a high-latitude location

S. Jouttijärvi [a,*], L. Karttunen [a], S. Ranta [b], K. Miettunen [a]

[a] Department of Mechanical and Materials Engineering, University of Turku, Vesilinnantie 5, 20500 Turku, Finland
[b] Turku University of Applied Sciences, Joukahaisenkatu 7, 20520 Turku, Finland

HIGHLIGHTS

- Economic value of PV electricity for a small-scale producer is analyzed.
- Modeled PV production and real electricity market data from Finland is used.
- Potential for self-consumption dominates the economic value of PV electricity.
- Vertical bifacial PV has superior production and value compared to monofacial PV.

ARTICLE INFO

Keywords:
Economic value of PV
Bifacial PV
Small-scale producer
High-latitude location

ABSTRACT

This study performs a techno-economic analysis of different photovoltaic (PV) systems suitable for detached houses in high-latitude locations and quantifies the key economic indicators affecting their competitiveness. Residential PV systems providing different temporal power production profiles are compared, accounting for the electricity price variations in the day-ahead market and the possibility of self-consuming the produced electricity. The procedure allows novel and comprehensive case study analysis that captures PV production, self-consumption, and dynamic electricity pricing, ultimately revealing the value of the produced PV electricity. This procedure is applied to a hundred case studies representing single-family houses with different PV systems, electricity load profiles, and electricity contracts. Vertical East-West mounted bifacial panels (VBPV) reached superior performance, with 9.1% higher overall production (with 2019 weather data) and 7.4%–10.9% higher economic value (with 2019 and 2022 electricity price data) for the produced PV electricity compared with monofacial PV. Thus, VBPV is an excellent choice for households economically, but the availability of suitable installation sites in the urban environment limits the possibility of its utilization. The economic value of PV electricity strongly correlates with self-consumed electricity due to avoided transmission fees and taxes, and a significant drop in total production causes only a minor reduction in value if the amount of self-consumed electricity remains similar. Thus, for a small-scale producer who orients the panels toward the East and the West instead of the South with a 45° tilt, the economic loss is significantly smaller (even as low as 12.6%) than the production loss (23.2%).

Abbreviations[1] [2]: AC, alternating current; DC, direct current; EEST, Eastern European Summer Time; MPV, monofacial photovoltaics; PV, photovoltaics; PVGIS, photovoltaic geographical information system; QC, quality control; STC, standard test condition; VAT, value-added tax; VRE, variable renewable energy; VBPV, vertical bifacial photovoltaics; A, area [m^2]; BF, bifaciality factor [%] or [no unit]; C, cost [€]; d, discount factor [%] or [no unit]; DHI, diffused horizontal irradiance [W/m^2]; DNI, direct normal irradiance [W/m^2]; E, electricity production or consumption [kWh/year] or [kWh/h]; GHI, global horizontal irradiance [W/m^2]; GTI, global tilted irradiance [W/m^2]; k_d, diffuse fraction [%] or [no unit]; MV, market value [€/year]; NC, net cost [€/year]; NPV, net present value [€]; p, price [c/kWh]; SV, specific value [€/year]; T, temperature [°C]; WS, wind speed [m/s]; ΔT, temperature difference [°C]; θ, zenith angle [°]; η_{STC}, standard test condition efficiency [%].

* Corresponding author.
E-mail address: sami.jouttijarvi@utu.fi (S. Jouttijärvi).

https://doi.org/10.1016/j.apenergy.2024.122924
Received 6 October 2023; Received in revised form 8 December 2023; Accepted 23 February 2024

1. Introduction

Reduced cost and extraordinary scalability have made solar photovoltaic (PV) power production a mainstream solution that is accessible from utility-scale to small producers. As the share of PV in electricity generation rises around the globe, its diurnal and weather-dependent nature poses some challenges. In particular, conventionally oriented PV panels, i.e., panels pointing toward the equator at an optimized angle, reach the production peak at solar noon and produce poorly during morning and evening when electricity consumption typically peaks. In a power system with a high share of PV and a limited adjustable generation capacity, extensive over-generation around noon and a need for imported electricity during morning and evening are common phenomena. The mismatch causes challenges for grid stability and supply security. Moreover, in an electricity market with hourly varying prices, such as the Nordpool day-ahead market [1], the imbalance between demand and supply causes a highly fluctuating price profile. The profitability of renewable energy is impacted by self-cannibalism; for instance, solar energy production in Germany sinks prices and profits around noon [2–5], while electricity prices in Finland drop significantly when there are good conditions for wind energy production. The production profile of PV can be significantly adjusted, particularly in Nordic conditions, to avoid this effect. However, such a techno-economic analysis of Nordic PV is lacking in the literature.

This study approaches these questions from the perspective of small-scale producer-consumers, i.e., prosumers. Two main strategies can be applied: demand can be moved to hours of high PV production, and PV peak production can be shifted toward hours of high demand. A typical prosumer is a house owner with their own PV power system installed on the roof. Such case studies are analyzed widely at low- and mid-latitudes [6–8]. However, in this paper, we study a high-latitude location, Finland, which has significantly different solar irradiation conditions, especially a high seasonal variation and a low average solar altitude angle [9]. Although Finland and other high-latitude locations are often thought to have too low solar irradiation for profitable PV production, the difference between Southern Finland and Central Europe is small. According to the Photovoltaics Geographical Information System (PVGIS) online tool [10], the total annual irradiation on optimally tilted planes in Turku (Southwest Finland) is only 1.9% smaller than in Kiel (Northwest Germany). From May to August, the irradiation in Turku is greater than in Kiel, enabling high PV production during summer. Combined with low solar elevation, this creates excellent conditions for vertical bifacial PV (VBPV) mounted in the East-West direction [11,12].

Besides the production and cost of PV, the third major factor affecting the economic feasibility is the electricity price, which has risen rapidly due to the ongoing energy crisis. The mean Nordpool spot price for Finland [13] (excluding taxes) was €154.04/MWh in 2022, €72.34/MWh in 2021, and €28.02–49.30/MWh in 2011–2020. Thus, the competitiveness of PV in Finland has increased tremendously.

The literature states that the PV orientation that maximizes the total annual production may differ from the orientation that maximizes self-consumption or results in the highest economic profits for a prosumer [14–16]. The market value of the produced PV electricity can be increased by shifting the azimuth, typically to the West from the South [14,15,17–19], since the electricity prices often peak in the afternoon/evening. Such a change in the alignment can lead to tens of percentage increase in the annual market value compared with the optimal production orientation [18]. When the share of PV in the energy markets increases significantly, this difference becomes greater [19].

The German electricity market, where the share of variable renewable energy (VRE), especially PV and onshore wind, is high, provides an opportunity to study the effect of large PV production. Overall, the price-decreasing impact of VRE on the electricity spot price increased from 2.89 c/kWh in 2014 to 8.89 c/kWh in 2017 [4], although it should be noted that without VRE, there would be more conventional coal and nuclear plants, which would affect the electricity price. However, the increase in VRE has made the German spot price more vulnerable to variation due to weather conditions [3,5]. In an analysis for 2030, the number of negative spot price hours was expected to increase from 254 h in 2019 to 258, 326, or 490 h in 2030, depending on the scenario regarding the other energy production portfolio. In 2019, the negative price hours were focused on nighttime and noon, whereas in all 2030 scenarios, the negative prices were strongly concentrated close to noon, highlighting the role of PV.

It is crucial to consider all production, consumption, and electricity price profiles when performing a holistic techno-economic analysis. Litjens et al. [20] compared the optimal panel orientation in the Netherlands in multiple cases, considering various residential and commercial consumption profiles, system sizes, and feed-in power limitations, aiming to maximize the electricity production, self-consumption, and total revenue with Dutch and German market prices. The optimal orientation is dependent on the case and optimized variable. For instance, for maximizing self-consumption, the optimal orientations were 26° tilt and 212° azimuth (clockwise from North), as well as 17° tilt and 188° azimuth, for residential and commercial systems, respectively. The total revenue increased to 5.4% compared with the orientation that maximized production. However, in some residential scenarios, maximizing the total revenue decreases self-consumption. Meriläinen et al. [16] studied the optimal PV orientations to maximize the value of the produced electricity for various load profiles in Finland. They showed that, unlike other studies, the azimuth is slightly shifted toward the East instead of the West when maximizing the revenues. The total annual value was only slightly sensitive to the change in orientation, and the dual-azimuth monofacial photovoltaic (MPV) systems performed better than single-azimuth systems for maximizing self-consumption.

The East-West oriented vertical bifacial PV (VBPV) has been shown to lead to higher annual electricity generation compared with the conventional South-facing PV in high latitudes [the production ratio of MPV and VBPV (front-side facing the East) systems was 91.7% in Bergen, Norway] [21] and slightly higher market revenues, at least in markets with high shares of South-facing PV [21]. However, studies on increasing the economic value of the produced PV electricity at the household level by utilizing VBPV are lacking in the literature. Although VBPV provides an improved match between PV production and electricity load compared to typical rooftop MPV, the availability of suitable installation sites in the urban environment is limited. Thus, creative architectural solutions that allow the utilization of VBPV as fence-like structures with a minimal land footprint and structural functionality in a built environment [11] are required to make this technology available to private consumers. The potential for the effective dual-use of the land with rooftop MPV and ground-mounted VBPV is visualized in Fig. 1. However, further studies in this field are required to ascertain the maximum available VBPV potential in different residential areas.

For a single prosumer, the orientation can be set by the orientation of the roof, among others. However, at the neighborhood level, the different orientations of buildings create various possibilities for different PV orientations. Vertical mounting is possible, for instance, when PV is used as a fence or a balcony divider [11]. Since the electricity pricing principles and the governmental policies (e.g., the lack of PV feed-in tariffs) in Finland favor self-consumed PV electricity over surplus sold to the grid, increasing self-consumption during high-price hours at the cost of reduced total production can be an economically feasible option for a prosumer. Moreover, increased self-consumption makes the prosumer more resilient against electricity price increases and disruptions in the electricity supply, thus increasing energy security. In this study, we analyze an extensive range of PV orientations and calculate the expected total annual production, building upon our previous works [22–24] and the value of the

---

[1] The subindexes for *E*, *GTI*, *SV*, and *T* are explained at their first appearance in the text.

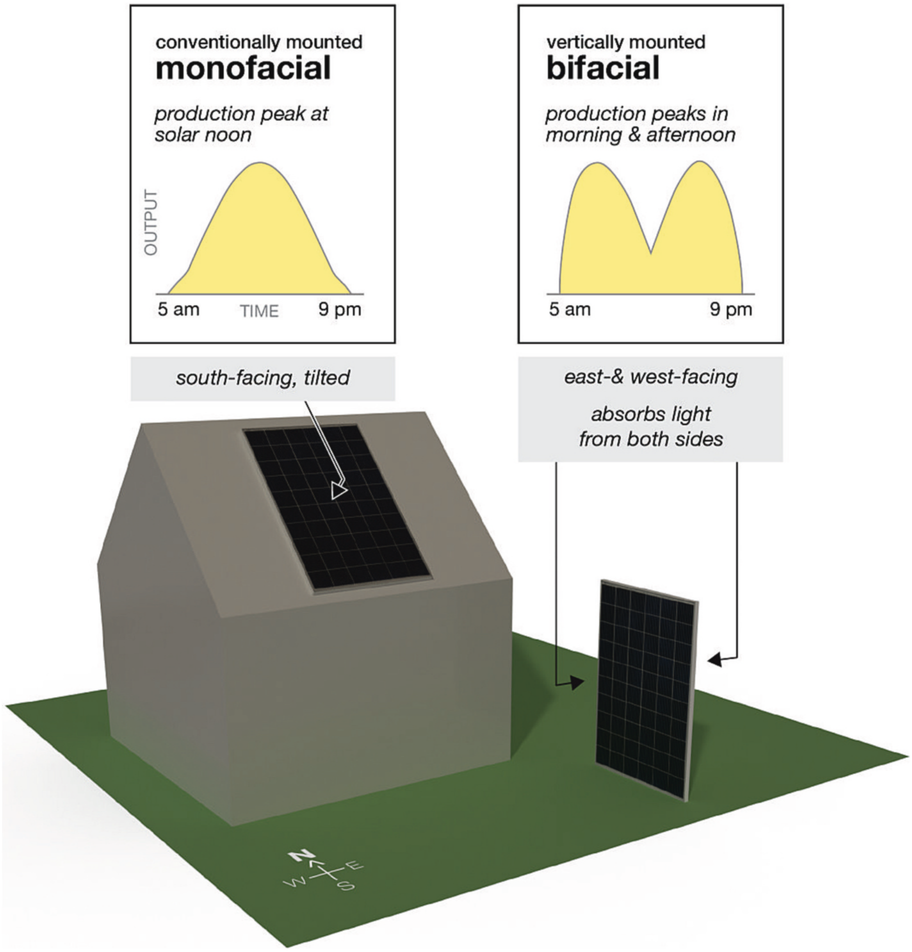

Fig. 1. A schematic figure of a rooftop-mounted MPV and ground-mounted VBPV panel. The illustrative power generation profiles during one sunny day are visualized.

produced electricity for prosumers with different electricity contracts (fixed-term or spot price). The different PV systems and electricity contracts are compared in terms of the total value of the produced PV electricity and the total annual net cost of the electricity.

2. Methods

2.1. Computational methods

Data processing, data filtering, solar irradiance and PV power production modeling, and annual simulations of the studied cases were performed computationally with Matlab and Python using the ready-made functions and tool packages of the software. Functions from the open-source PVlib library [25], developed by Sandia National Laboratories, were utilized in the solar irradiance modeling, either in their original form or after modification by the authors. The other codes used in this study were written by the authors.

2.2. Creating PV power production profiles

2.2.1. Data collection

A weather station in Turku, Finland (60°N, 22°E) was used as a raw data source. The global horizontal irradiance (*GHI*) data were measured with two pyranometers (Kipp and Zonen SP10, spectrally flat class A). Ambient temperature (T_A) was monitored by Vaisala Hmp110, and wind speed (*WS*) was monitored with Produal VS3000. The datasets covered the year 2019 with a one-minute resolution.

2.2.2. Data processing: creating the accepted set

The initial quality control (QC) was done as follows. The datapoint was rejected as missing if at least one of the four measured values (two *GHI*s, T_A, and *WS*) was missing. Moreover, if the *GHI* values from the two pyranometers had a difference larger than 20 W/m^2, the datapoint was rejected as inconsistent. Only 87 datapoints were removed as missing or inconsistent, indicating the high quality of the original datasets. For the accepted points, the *GHI* value was set as the average of the two sensor values. Then, the dataset was filtered so all datapoints with $GHI < 30$ W/m^2 were removed, thus eliminating nighttime and very dark daytime data. After processing, the amount of valid datapoints was 201,227, representing 38.3% of the full-year minute-level dataset length (525,600), where nights are also included. The monthly acceptance percentage varied from 4.7% (Dec) to 65.3% (Jul) due to the extensive contrast in the length of day and clearness of weather between winter and summer in Finland. Compared with the case when all *GHI* values greater than zero were accepted, this approach provided a 1.15% lower total annual *GHI* and a 21.9% lower amount of valid datapoints. Thus, the loss of modeled power production due to the elimination of the low *GHI* values is small, and the accepted dataset represents the conditions when the PV systems produce electricity well or reasonably.

2.2.3. Decomposition modeling

The measured *GHI* values were used to model direct normal irradiance (*DNI*) and diffused horizontal irradiance (*DHI*). The diffuse fraction (k_d) was calculated with the Starke decomposition model [26] using coefficients for the Dfc climate zone according to the Köppen-Geiger classification [27]. The *DHI* and *DNI* were calculated as follows:

$$DHI = k_d \bullet GHI \tag{1}$$

$$DNI = \frac{GHI - DHI}{cos\theta} \tag{2}$$

where θ is the solar zenith angle. Since this method is sensitive to errors with low solar elevations, a QC method developed for high-latitude locations [9] was applied to replace the unrealistically high *DNI* values with realistic approximations. Finally, the *DHI* values were recalculated using post-QC *DNI*.

Since decomposition models can be inaccurate with low solar elevation angles, using modeled, GHI-derived data with vertical installations can form a significant error source. However, the GHI data and the modeling chain used in this study were validated against the measured VBPV power production data from the same location. Therefore, this error source is considered feasible.

2.2.4. Transposition modeling

Global tilted irradiance (*GTI*) on specific surfaces was calculated with the Perez4 transposition model [28]. The calculations were done with all possible orientations over the sky dome with 1° resolution for tilt angle (0°–90°) and 2° resolution for azimuth angle (0°–358°), resulting in 16,201 different orientations (for tilt = 0°, the azimuth is irrelevant). In this study, the azimuth is defined so that azimuth = 0° stands for North, and the value increases clockwise. An alternative definition for azimuth is that 0° stands for South, and the value increases clockwise (i.e., 90° is West and − 90° is East), which is used in some of the references.

2.2.5. Parametrizing the irradiance-to-power model

Irradiance-to-power (I2P) conversion was done using the 6k regression model [29]. The model was parametrized by validating the calculated power production of the VBPV panel located in Turku, Finland, against the respective measured data from the setup presented in [24] from 2019. In total, there were 201,227 valid datapoints. This approach could cause an additional error for MPV power production modeling since respective validation data for MPV were unavailable. A short validation of the used approach against free (PVGIS) and commercial (PVSyst) software provided consistent results (data not shown); thus, the approach is considered feasible. The equations for modeled power production are as follows:

$$\begin{aligned} P = A \bullet GTI_{rel} \bullet \big(&\eta_{STC} \bullet GTI_{STC} + x_1 \bullet ln(GTI_{rel}) + x_2 \bullet ln(GTI_{rel})^2 + x_3 \\ &\bullet T_{rel} + x_4 \bullet T_{rel} \bullet ln(GTI_{rel}) + x_5 \bullet T_{rel} \bullet ln(GTI_{rel})^2 + x_6 \bullet T_{rel}^2 \big) \end{aligned} \tag{3}$$

$$GTI_{rel} = \frac{GTI_{eff}}{GTI_{STC}} \tag{4}$$

$$GTI_{eff} = GTI_F + BF \bullet GTI_R \tag{5}$$

$$T_{rel} = T_C - T_{STC} \tag{6}$$

$$T_C = T_M + \Delta T \bullet \frac{GTI_{tot}}{I_{STC}} \tag{7}$$

$$T_M = T_A + GTI_{tot} \bullet e^{x_{T1} + x_{T2} \bullet WS} \tag{8}$$

$$GTI_{tot} = GTI_F + GTI_R \tag{9}$$

where A is the area of the panel, $\eta_{STC} = 17.7\%$ is the standard test condition (STC) efficiency, $GTI_{STC} = 1000\ \mathrm{W/m^2}$ is the STC-irradiance, GTI_F is the modeled front-side *GTI*, $BF = 90\%$ is the bifaciality factor, and GTI_R is the modeled front-side *GTI*. The parameters $x_1 \ldots x_6$ are determined experimentally for the 6k model, whereas x_{T1} and x_{T2} are determined based on validating Eq. (8) against the measured VBPV data [24] for VBPV and using close-roof mounting parameters [30] for MPV. The method for calculating the cell temperature and the constants used are adapted from the literature [30,31].

2.2.6. Irradiance-to-power

The modeled power production profiles were calculated based on *GTI*, T_A, and *WS*. The STC-efficiency $\eta_{STC} = 17.7\%$ was used [24]. The power production for each minute-level datapoint was calculated based on the parametrized 6k model for the VBPV (both front side facing East and front side facing West cases) using *GTI*-profiles for tilt 90° and azimuths 90° and 270°. For MPV, the equations were modified so that

$$GTI_{eff} = GTI_{tot} = GTI_F \tag{10}$$

Since the 6k model is parametrized based on measured direct current (DC) power production, it excludes the inverter losses. Suppliers like Solis [32] and Growatt [33] offer inverters that are suitably sized for single-house rooftop PV systems with EU efficiency (a weighted efficiency based on how often the inverter will operate at different output levels) of 97.5%. In simulations, a loss factor of 3% was used to include inverter loss and additional losses from alternating current (AC) wiring. Finally, the power production datasets were aggregated to hourly level by summing all production within a full hour, starting from 01.01.2019 00:00:00 (Eastern European Summer Time, EEST). As an example of the procedure, a regression plot for VBPV comparing hourly aggregated measured and modeled electricity production is shown in Fig. 2. Most of the datapoints are very close to the regression line, especially when production is high.

Five profiles were chosen to be analyzed in detail as case studies, representing realistic systems for domestic installations. They are summarized in Table 1. For MPV, two tilt angles, 15° (T15) and 45° (T45), were chosen. These angles represent slightly tilted panels on a flat roof and parallel-to-roof panels on a steeply tilted roof. The azimuth of 180° (S) represents conventional installation, aiming to maximize annual energy production, whereas the 1:1 mixture of azimuths of 90° (E) and 270° (W) aims to maximize the power production during peak electricity load hours and provides contrast compared with an azimuth of 180°. Alternatively, the East-West orientation of the panels can be forced by the surroundings (e.g., a detached house with a tilted roof, with the sides

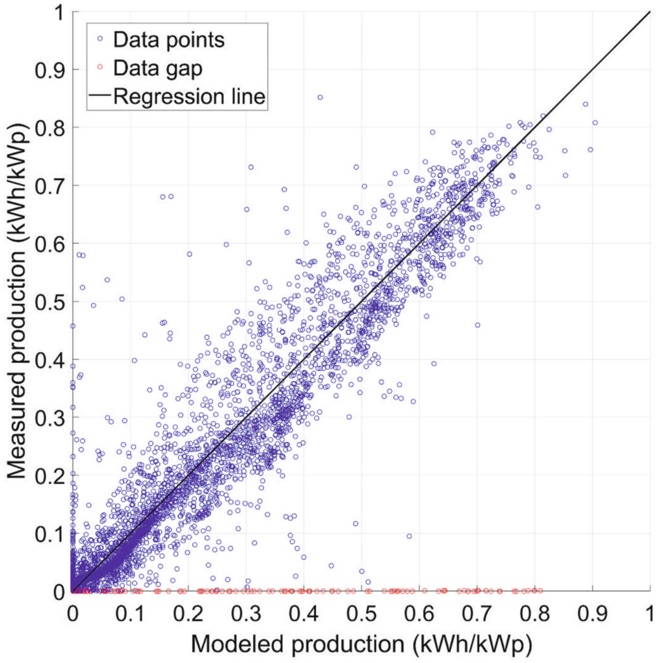

Fig. 2. A regression plot for VBPV, showing normalized and hourly aggregated modeled and measured electricity production. The red circles represent a short gap in the measured data (i.e., the measured data is zero, but the modeled data, which is based on the irradiation, is describing the realistic production).

Table 1
Used PV system orientations. The percentages show the distribution of PV panels for different azimuths.

Notation	Tilt (°)	Azimuth(s) (°)
T15S	15	180
T15EW	15	90 (50%), 270 (50%)
T45S	45	180
T45EW	45	90 (50%), 270 (50%)
VBPV*	90	90 (50%), 270 (50%)

* 90% bifaciality.

facing the East and West). This provides four different MPV profiles, which cover different rooftop installations.

For the analyzed VBPV system, the panels were assumed to have a 1:1 ratio of the front side facing East and the front side facing West panels to provide a balanced power production profile. Bifacial panels were studied only in a vertical configuration. This choice is justified by the scope of the study, a techno-economic analysis of residential PV systems. The BPV panels could be mounted conventionally to the ground (suitable tilt and 180° azimuth angles); however, they are directly competing with other land use purposes in such a case, and the effective dual-use of land, which is the key factor when integrating PV to residential areas, is lost. Moreover, the benefits of VBPV are highlighted at high-latitude locations [12,21].

The power production with these systems, sized to 4.0 kWp, is presented in Fig. 3. With the 45° tilt, the EW system enabled higher production during the morning and evening at the cost of significantly lower production during the rest of the day. With the 15° tilt, the effect of azimuth was significantly smaller. VBPV had a significantly different profile, with two peaks (morning and evening) instead of one noon peak.

2.3. Electricity consumption and pricing data

The electricity consumption profiles used in this analysis present relevant types of consumers from the electricity consumer cluster classification by Tampere University on behalf of the Finnish Energy Authority [34]. The profiles are averages from individual customers belonging to each cluster. Therefore, high power demand peaks caused by electric stoves, for instance, are averaged out. Thus, the profiles represent average consumer behavior and may differ significantly from the profiles of individual houses, although the house is included in the corresponding cluster. This approach is considered feasible since the aim is to produce results that are applicable widely and can be generalized easily to the local and national levels. Thus, using consumption data from an individual house creates bias based on the consumption behavior of the residents.

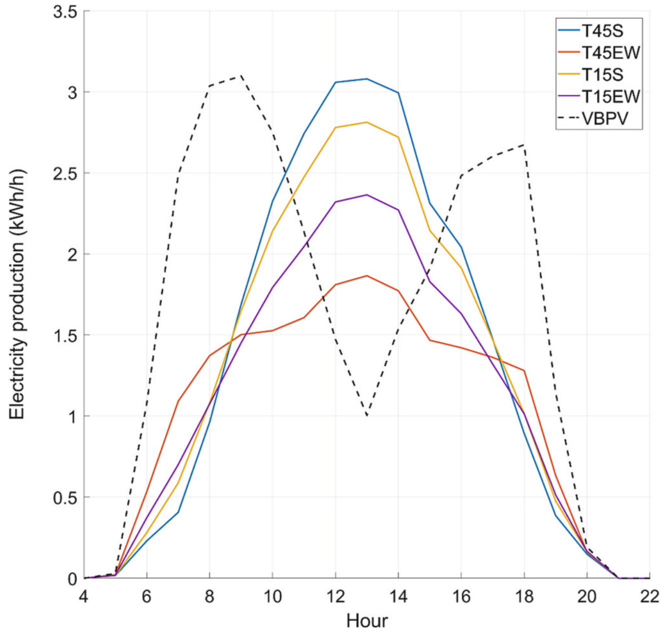

Fig. 3. The electricity production with different PV production profiles for a 4 kWp system on a single mostly sunny day, May 09.

Three profiles representing detached houses with different heating solutions (Load1, Load2, and Load3) were adapted directly from [34]. Each profile contains electricity consumption for one year with hourly resolution. The shape of the profile and the total annual electricity consumption depend on the heating solution of the house. The annual consumption, heating solution, and energy efficiency of the houses are presented in Table 2. Each of these load profiles was identified as a separate type of consumer from the real market data in [34], where the total electricity load was distributed among 14 types of consumers, covering residential houses, agriculture, business, and industry. Thus, each presents a significant number of detached houses.

Moreover, one in-house modified profile, Load3F, was used. It represents a house with reserved heating as a flexible load, with equal daily heating and other electricity usage needs compared with Load3. In practice, a house with a Load3F consumption profile has a hot water tank as thermal storage. The tank can be heated when PV electricity is available, and the stored heat can be used to satisfy the heat and hot water demands of the house. The profiles are generated for all PV systems separately by assuming that all the electricity used for heating either the house or hot water is flexible within 24 h. In other words, if there is surplus PV electricity available, it can be used to produce heat that is consumed within the next 24 h instead of selling it to the grid. A perfect forecast for the heat demand for the next 24 h is assumed.

The load profiles are presented in Fig. 4 as the average daily profiles. These daily profiles are obtained by taking the monthly mean values of each hour of the day. Profile Load1 is relatively low, with a peak in the evening and a valley during nighttime corresponding to domestic activity. The seasonal variation is relatively low. The profile Load2 has a similar shape to Load1 but has additional season-dependent consumption due to electric heating. This additional consumption is high during winter and low during summer. Profile Load3 has a very high peak (between 4 and 10 kW, depending on the season) around midnight due to the heating: the heat demand for the whole day is satisfied by utilizing cheap night electricity for a few hours. During winter, profile Load3F is very similar to Load3 since the amount of PV electricity available is low. However, during summer, Load3F has a lower peak around noon instead of a high peak during the night since the produced PV electricity is used for heating. In Fig. 4, the Load3F is shown for a 4.0 kWp PV system with T45S orientation.

The total price paid for electricity taken from the power grid for an individual consumer in Finland consists of three main components: cost of electricity, cost of transmission, and taxes. The electricity price can be fixed or dynamic depending on the contract type that the customer has chosen and includes value-added tax (VAT). The transmission fee, electricity tax, and supply security fee (and VAT for all of them) are charged by the distribution system operator as a fixed cost per kilowatt hour consumed. The exact amount of this cost depends on the consumer type and location. In addition, there may be fixed monthly fees for both

Table 2
The load profiles and their key characteristics.

Name	Electric heating	Energy efficient house	Annual consumption (kWh)	Type consumer # in [34]
Load1	No	No	5000	4
Load2	Direct	Yes	10,000	5
Load3	Reserving	No	19,000	7
Load3F	Reserving, Flexible	No	19,000	Modified from 7

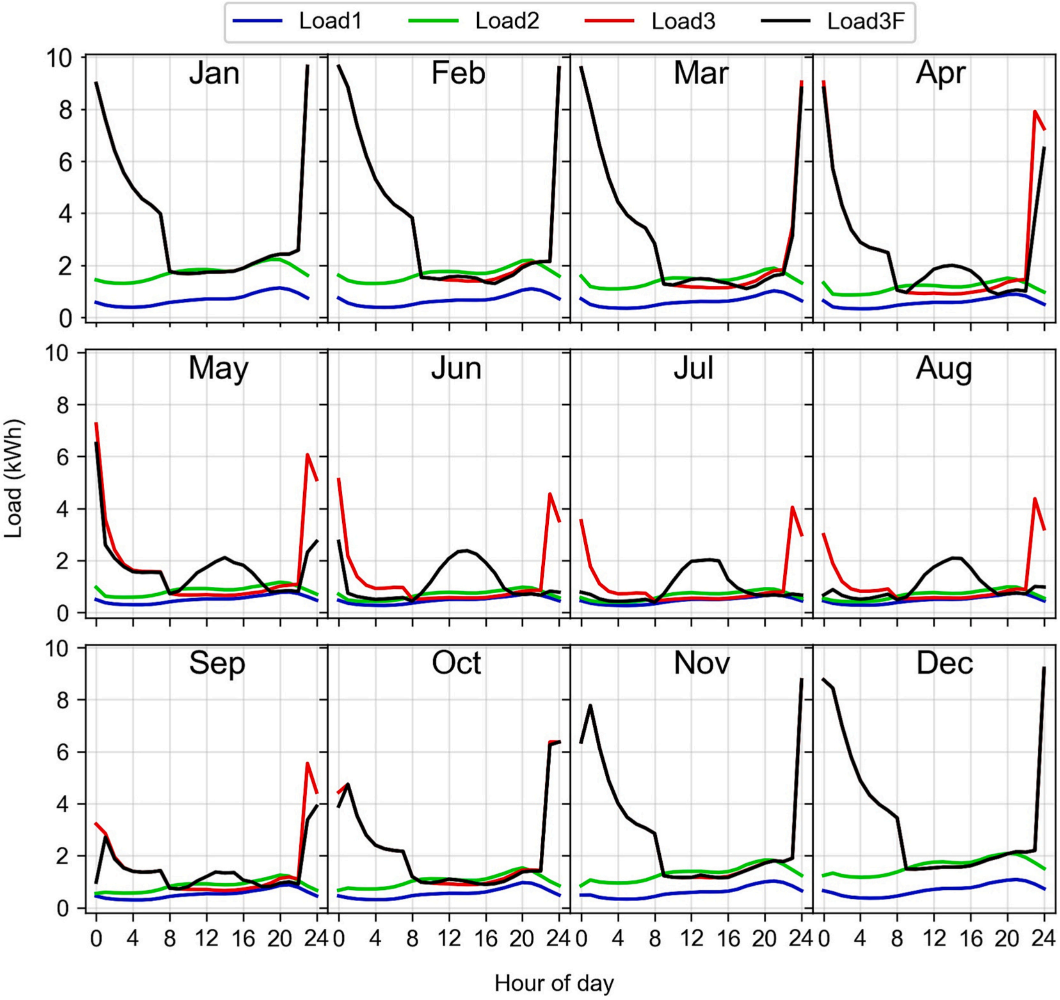

Fig. 4. Daily average load profiles with one-hour resolution plotted for each month separately (UTC + 03 time zone). Profiles Load1, Load2, and Load3 are the same for all PV systems, but profile Load3F depends on the size and orientation of the PV system. The profile Load3F shown in the figure is for a 4.0 kWp solar power system with production profile T45S.

electricity and transmission, but these are assumed to be identical in all cases and are thus excluded for further analysis. Since feed-in tariffs are unavailable for PV producers in Finland, the possible surplus generation has to be sold at the market price. In practice, the electricity selling contracts available for Finnish residential customers are bound to the spot price.

We consider five electricity purchase pricing and two electricity sell pricing scenarios, covering both the normal market situation (2019) and the energy crisis (2022). The two dynamic purchase pricing scenarios (Spot19 and Spot22) and the two sell pricing scenarios (Sell19 and Sell22) are based on the hourly spot prices (p_{spot}) of Finland [1] in 2019 and 2022, respectively. To be compatible with the Finnish electricity market, a VAT (10% for December 2022, 24% otherwise) and a margin ($p_{margin} = 0.4$ c/kWh, including VAT) were added to the spot price for the Spot19 and Spot22 contracts. For the Sell19 and Sell22 contracts, p_{margin} was deducted from the spot price. Taxes were excluded from the sell contracts. According to Finnish legislation, small-scale producers of renewable energy (nominal peak power < 100 kW and annual revenue < €10,000) are relieved from taxation. Since the case studies represent single detached houses, the studied systems stay well below these criteria.

Three fixed-price (p_{fixed}) purchase scenarios were used: Fixed19 represents the 2019 case (the consumer made a two-year fixed price contract in July 2018), while Fixed22A and Fixed22B represent the 2022 case (two-year contract in July 2021 and one-year contracts in July 2021 and July 2022). Two different fixed contracts for 2022 were used since the electricity price in fixed contracts changed dramatically during 2022 (Table 3). For the Fixed22A and Fixed22B contracts, the VAT deduction

Table 3
Electricity price components. K2: detached house, electric stove, no electric heating, fuse 3 × 25 A, consumption 5000 kWh/year; L2: detached house, partially reserved electric heating, fuse 3 × 25 A, consumption 20,000 kWh/year. Values for K2 were used for Load1; values for L2 were used for Loads2, 3 & 3F.

Price component	K2 (c/kWh)	L2 (c/kWh)
Electricity mean[1] spot price[2] 2019	5.46	5.46
Electricity mean[1] spot price[2] 2022	18.74	18.74
Fixed electricity price[2] 2019	6.10	5.39
Fixed electricity price[2] 2022	A: 6.46/B: 6.49 (Jan–Jun), 17.10 (Jul–Dec)	A: 5.70/ B: 5.94 (Jan–Jun), 15.28 (Jul–Dec)
Transmission cost[3] 2019	6.93	5.42
Transmission cost[3] 2022	6.22	4.96
Margin	0.40	0.40

[1] Arithmetic average of hourly spot prices.
[2] Inc. VAT 24%. For Dec 2022, 10% VAT was deducted.
[3] Inc. VAT 24%, electricity tax, and supply security fee.

for December 2022 was transferred completely to the consumer price. The exact values for the p_{fixed} purchase prices were determined as average prices for the contracts made in given months for the corresponding customer type, according to statistics from the Energy Authority [35]. For each load profile referred to earlier [34] and used in this study, the p_{fixed} and $p_{transmission}$ values for the most representative customer type were used. For Load1 (detached house without electric heating, consumption of 5000 kWh/year) [34], p_{fixed} and $p_{transmission}$ for customer type K2 (detached house, electric stove, no electric heating, consumption 5000 kWh/year) [35] are used. For the other load profiles (detached houses with electric heating, consumption of 10,000 or 19,000 kWh) [34], prices corresponding to customer type L2 (detached house, partially reserving electric heating, consumption 20,000 kWh/year) [35] were used.

The electricity transmission cost, electricity tax, supply security fee, and VAT for all three components were aggregated into one variable ($p_{transmission}$), which is charged based on consumption, year, customer class type, and geographical location. This aggregated value was determined from Energy Authority statistics [35] based on the year and customer type. In all cases, the house is assumed to be in Turku (distribution system operator: Turku Energia Sähköverkot Oy). All fixed price components for the different cases used in this study are presented in Table 3. To sum up, the purchase and sell prices are defined as follows:

$$p_{purchase} = \begin{cases} p_{spot}\cdot\left(1+\dfrac{VAT}{100}\right)+p_{margin}+p_{transmission}, \text{for spot price contracts (11a)} \\ p_{fixed}+p_{transmission}, \text{for fixed price contracts (11b)} \end{cases}$$

$$p_{sell} = p_{spot} - p_{margin} \tag{12}$$

The purchase and sell contracts are paired based on the year, i.e., Sell19 contract is used with Spot19 and Fixed19 contracts. Thus, there were a total of five different electricity trade (including purchase and sell) contract combinations. The contracts are summarized in Table 4.

The different electricity price variants for K2-type consumers are presented in Fig. 5A and Fig. 5B for 2019 and 2022, respectively. Since the electricity selling prices (Sell19 in 5 A and Sell22 in Fig. 5B) are given by Eq. (12), they are very close to the spot prices, and the corresponding curves overlap. For 2019 (Fig. 5A), the purchase price with the spot-price contract (Spot19) is, on average, slightly lower than the fixed price, although the daytime price is higher during certain months. The benefit of PV electricity self-consumption is clear. During summer months, the daytime purchase prices are mostly 12–14 c/kWh, whereas the sell price is 4–6 c/kWh. Overall, the electricity prices are at a low, stable level, representing a steady market situation in Finland.

By contrast, in 2022 (Fig. 5B), the energy crisis due to Russia's attack on Ukraine has taken effect, and the spot-price contract is extremely expensive since the spot price responds immediately to the changes in demand and supply in the market. Two major factors reduced the supply and increased the electricity price: i) terminating the direct import of electricity from Russia to Finland in Spring 2022 and ii) reducing the import of natural gas from Russia to Central Europe. However, the selling price for the surplus PV electricity is also high, allowing individual prosumers to make high profits, especially during August. The clear winners in 2022 are the consumers who made two-year, fixed-price contracts before the crisis (Fixed22A). During certain hours, the sell price of the surplus PV is higher than the fixed purchase price. This condition would make it profitable to sell all PV production and buy the consumed electricity, but such is forbidden. The electricity contracts offered to the prosumers allow selling electricity only when their demand is satisfied completely by their own production.

Table 4
The summary of the electricity contracts used. For numeric values, refer to Table 3.

Name	Type	Main price component	VAT	Margin	Transmission cost
Spot19	Buy	Spot price 2019	Yes	Added	2019
Fixed19	Buy	Fixed price 2019	Yes	No	2019
Spot22	Buy	Spot price 2022	Yes	Added	2022
Fixed22A	Buy	Fixed price 2022 (A)	Yes	No	2022
Fixed22B	Buy	Fixed price 2022 (B)	Yes	No	2022
Sell19	Sell	Spot price 2019	No	Deducted	No
Sell22	Sell	Spot price 2022	No	Deducted	No

2.4. Economic and technical indicators

To compare different PV systems, the following indicators are used (as a function of system size):

Total annual electricity production (E_A) was calculated for each MPV orientation by summing the generated power over the year. For the five PV profiles analyzed with various consumption profiles, the total annual self-consumed ($E_{A,SC}$) and surplus electricity ($E_{A,surplus}$) were calculated separately. The equations for calculating E_A, E_{SC}, and $E_{surplus}$ are presented below:

$$E_A = \sum E_{PV} = E_{A,SC} + E_{A,surplus} = \sum E_{SC} + \sum E_{surplus} \tag{13}$$

$$E_{SC} = \begin{cases} E_{PV}, \text{ if } \mathrm{E_{PV}} \leq \mathrm{E_{load}} \text{ (14a)} \\ E_{load}, \text{if } \mathrm{E_{PV}} > \mathrm{E_{load}} \text{ (14b)} \end{cases}$$

$$E_{surplus} = \begin{cases} 0, \text{if } \mathrm{E_{PV}} \leq \mathrm{E_{load}} \text{ (15a)} \\ E_{PV} - E_{load}, \text{if } \mathrm{E_{PV}} > \mathrm{E_{load}} \text{ (15b)} \end{cases}$$

where E_{PV} is the PV production and E_{load} is the consumption in a given hour.

Total annual market value of electricity *MV* was obtained for all PV orientations by multiplying the hourly generated power with the corresponding hourly electricity spot price p_{spot} as follows:

$$MV = \sum E_{PV}\cdot p_{spot} \tag{16}$$

This is a popular indicator of the general potential value of the produced electricity [14,18,19], but neglects the price differences between self-consumed and surplus electricity, which is important from the prosumers' perspective.

Total annual consumers' specific value of electricity *(SV)* was calculated for the five PV profiles as the sum of *SV* of self-consumed electricity (SV_{SC}) and *SV* of surplus electricity ($SV_{surplus}$) with the following formula:

$$SV = SV_{SC} + SV_{surplus} = \sum\left(p_{purchase}\cdot E_{SC}\right) + \sum\left(p_{sell}\cdot E_{surplus}\right) \tag{17}$$

where $p_{purchase}$ is the price of purchased electricity (either spot price or fixed contract), E_{SC} is the self-consumed PV production, p_{sell} is the price of sold electricity, and $E_{surplus}$ is the surplus PV production. This indicator is specific to a consumption profile and indicates the actual value of production when considering the separated values for self-consumed (i.e., the cost circumvented by avoiding electricity purchase from the grid) and surplus (i.e., the revenue for selling electricity to the grid) electricity. *SV* is used as the main comparison criterion because it represents the actual economic value of PV electricity, considered from a small-scale producer's perspective.

The total annual net cost (*NC)* was calculated by taking the sum of the purchased electricity over the year as follows:

$$NC = \sum\left(E_{decifit}\cdot p_{purchase} - E_{surplus}\cdot p_{sell}\right) \tag{18}$$

$$E_{deficit} = \begin{cases} 0, \text{if } \mathrm{E_{PV}} > \mathrm{E_{load}} \text{ (19a)} \\ E_{load} - E_{PV}, \text{if } \mathrm{E_{PV}} \leq \mathrm{E_{load}} \text{ (19b)} \end{cases}$$

NC represents the total annual electricity bill of a consumer

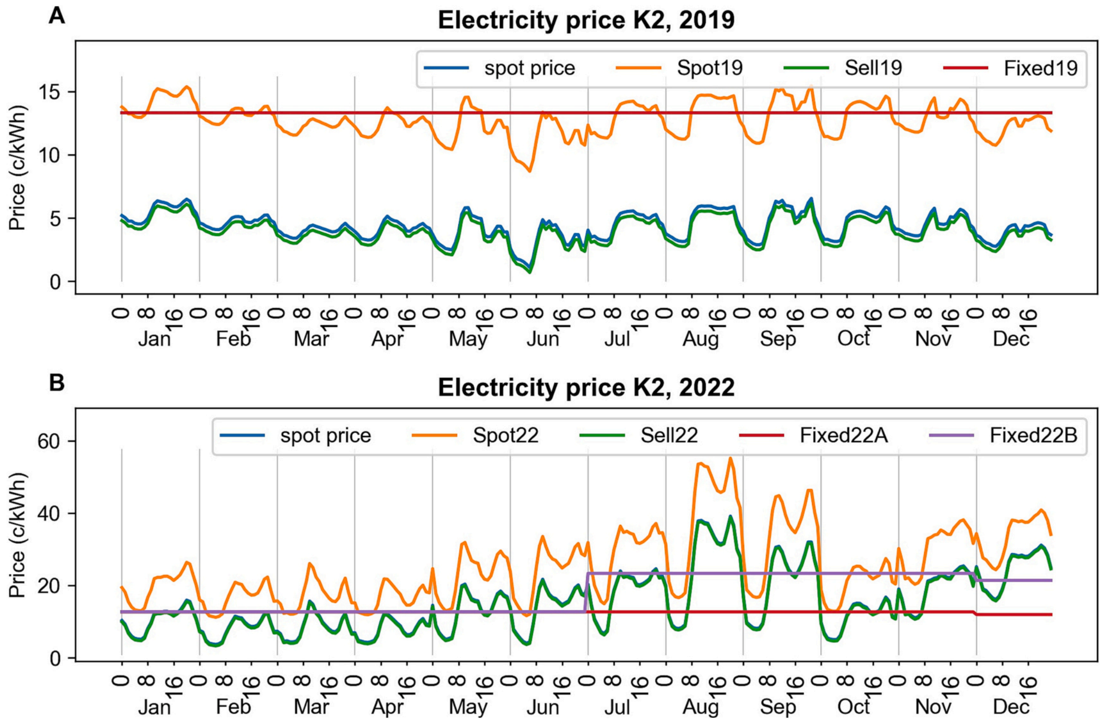

Fig. 5. Daily average price profiles with one-hour resolution, plotted for each month separately for 2019 (A) and 2022 (B) in the UTC + 03 time zone. Customer type-dependent values are plotted for customer type K2. The purchase prices include transmission costs and taxes. In (B), the "spot price" curve almost overlaps with the "Sell22" curve for the whole year, and the "Fixed22A" curve almost overlaps with the "Fixed22B" curve from Jan to Jun; therefore, the "spot price" curve and the "Fixed22A" curve from Jan to Jun are visually unavailable in (B).

(excluding constant monthly fees) and allows a concrete comparison of the yearly savings between the different orientations and scenarios. *NC* is connected to *SV* via the following equation:

$$NC = NC_0 - SV \tag{20}$$

where NC_0 is the *NC* without the PV system (i.e., the annual electricity bill for a house without PV).

Net present value (*NPV*) for the produced PV electricity includes the effect of decreasing the value of money when comparing current and future cash flows. Since the PV system requires a large initial investment, most of the costs occur immediately, whereas the revenue (including savings from self-consumed and revenue for surplus production) is distributed almost evenly for the whole lifespan of the system. The total net present value for the PV system can be calculated as

$$NPV = -C_{inv} + \sum_{i=1}^{n}\left(\frac{SV_i - C_{O\&M,i}}{(1+d)^n}\right) \tag{21}$$

where C_{inv} is the investment cost, *n* is the expected lifetime of the PV system in years, $C_{O\&M,i}$ is the operation and maintenance cost for year *i*, and *d* is the discount factor.

3. Results

3.1. PV electricity production and market value

The annual power production of the MPV systems with different orientations is shown as a contour plot in Fig. 6. The maximum value (163 kWh/m^2) is achieved with 41° tilt and 180° azimuth, represented by the black circle in Fig. 6. The contour lines show how the production decreases when the tilt and/or azimuth is changed away from the optimal value, e.g., if an orientation is at the 90% contour line in Fig. 6, the corresponding PV system produces 90% of the electricity produced by an optimally oriented PV system. The same logic with the contour lines is applied in Fig. 7. However, for the shown quantity and its unit, the reader is always referred to the header and caption of the particular figure.

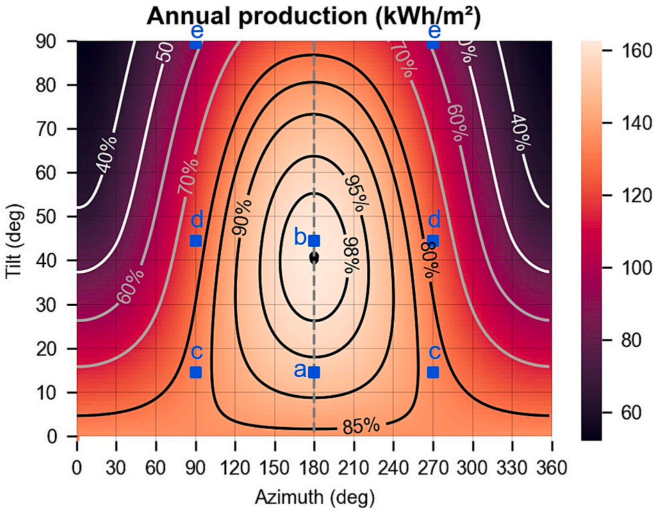

Fig. 6. The total annual production of the MPV systems as a function of tilt and azimuth angles. The maximum value was 163 kWh/m^2 with an azimuth of 180° and a tilt of 41°. The orientations studied in detail are shown as blue squares. Resolution: 1° for tilt and 2° for azimuth. The labeled blue squares represent the orientation(s) of the PV systems: T15S (a), T45S (b), T15EW (c), T45EW (d), and vertical East- and West-facing surfaces (e). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

The cases studied in more detail are shown in Figs. 6–8 with labeled blue squares. For the MPV systems, the difference in the optimal orientation is shown directly in the particular figure. For VBPV, the shown orientations represent the East- and West-facing surfaces

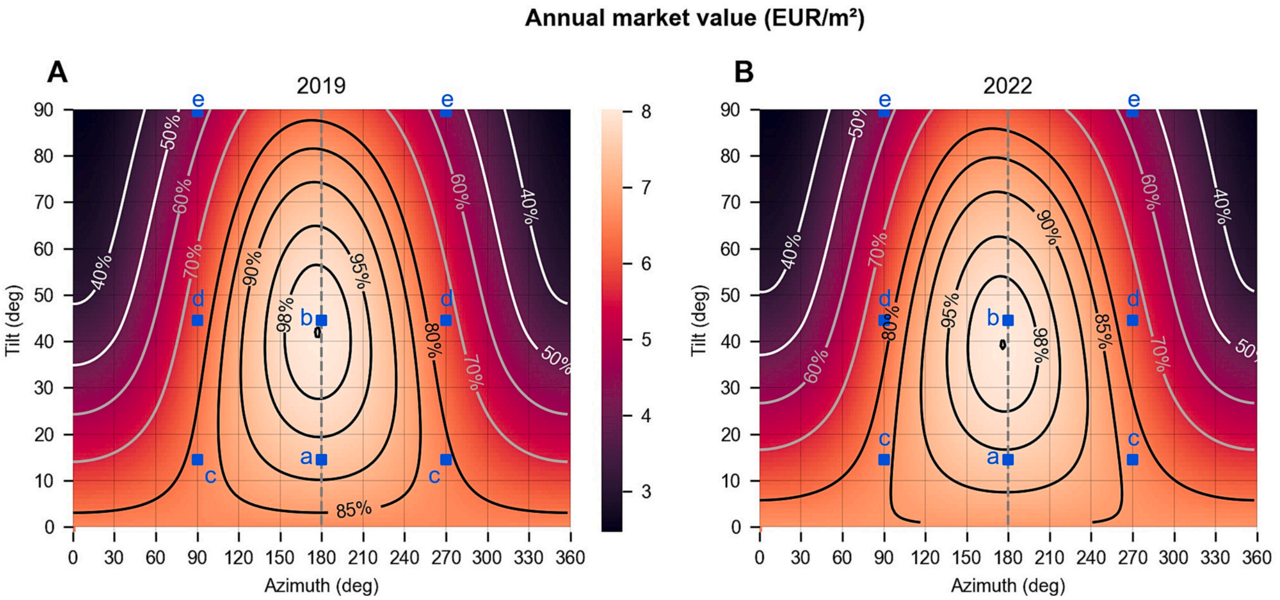

Fig. 7. The MV of the produced PV electricity for MPV systems as a function of tilt and azimuth angles. A: Year 2019 prices, maximum value of €8.0/m^2 with azimuth 178° and tilt 42°. B: Year 2022 prices, maximum value of €29.7/m^2 with azimuth 176° and tilt 39°. The orientations studied in detail are shown as blue squares. Resolution: 1° for tilt and 2° for azimuth. The labeled blue squares represent the orientation(s) of the PV systems: T15S (a), T45S (b), T15EW (c), T45EW (d), and vertical East- and West-facing surfaces (e). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

separately; thus, the comparison of the VBPV against an optimally oriented MPV system is more complicated. The limited bifaciality of the panels and the different operating temperatures of a VBPV and a vertical MPV panel need to be considered. However, the sum of the values shown for the VBPV faces in Fig. 6 provide a rough scale approximation of the potential of VBPV against optimally oriented MPV.

When considering the annual electricity production (Fig. 6), T45S is almost at the optimal spot, T15S is between the 90% and 95% curves, T15E and T15W are between the 80% and 85% curves, and T45E and T45W are slightly outside the 80% curve. The orientations of the VBPV faces (90° tilt, 90° and 270° azimuths) are close to the 60% curve. However, since VBPV can produce electricity from both sides, it has a higher production than the optimal MPV system, even when the bifaciality factor is considered.

The *MV*s of electricity for each MPV orientation with Spot19 and Spot22 contracts are presented as contour plots in Fig. 7A and B, respectively. For Spot19, the contour line pattern is rather similar to the annual production contour plot in Fig. 6, with the maximum value of €8.0/m^2 reached with 42° tilt and 178° azimuth. For Spot22, the maximum *MV* is almost four times higher (€29.7/m^2) and achieved with 39° tilt and 176° azimuth. Overall, the *MV* in 2022 (Fig. 7B) favors lower tilts and East-shifted azimuths when compared with the *MV* in 2019 (Fig. 7A) and the total production (Fig. 6). This result is due to the high spot prices during summer months between morning and noon (Fig. 5B); thus, maximizing production during these hours is favorable, even at the cost of total production. When compared with the literature, the small East shift for maximizing the *MV* is consistent with the conclusions of Meriläinen et al. [16], who also studied PV in Finland. The differences from other studies [14,15,17–19] can be explained by the different energy production portfolios in different countries. Finally, it should be noted that the *MV* shown in Fig. 7 is the tax-free spot price-based value, and, thus, differs from the real value of the produced PV electricity. However, it indicates how the dynamic market-based pricing affects the optimal orientation of the PV systems.

3.2. PV electricity value for the case studies

To analyze the economic feasibility of the different PV systems, the *SV* was used as a main indicator since it represents the realized net effect on the electricity bill due to its own PV production. The annual simulations with hourly level were done with the four load profiles (Section 2.3), the five electricity contracts (Section 2.3), and the five PV production profiles (Section 2.2). The PV system sizes varied between 0.0 and 8.0 kWp, with 0.4 kWp intervals. Since the number of simulated scenarios is extensive, 2000 scenarios with PV and 20 reference scenarios without PV, the focus of this section is on the key results and their visualization. Numeric data are given for simplicity only for the 4.0 kWp systems, reducing the number of PV cases to 100.

To obtain a better understanding of the sensitivity of *SV* to panel orientation, *SV*s are first presented as a function of panel orientation as contour plots in Fig. 8 for Load1, 4.0 kWp PV system size, and four various pricing scenarios: Spot19 (Fig. 8A), Spot22 (Fig. 8B), Fixed19 (Fig. 8C), and Fixed22A (Fig. 8D). Regarding the electricity price scenarios of 2019 (Fig. 8A and C), the optimal SV is obtained with an azimuth pointing slightly toward the West (186°), in contrast to the *MV* that was maximized with a slight shift toward the East. This observation suggests that shifting the production peak later from the optimal azimuth for power production increases the economic value for the given Load1, likely due to slightly higher electricity demand (and thus, the potential to self-consume more PV) during the afternoon). However, the contour lines are further away from each other compared with the contour lines of the total production (Fig. 6) and *MV* (Fig. 7), indicating that the *SV* is less sensitive to panel orientation with electricity prices from 2019. This result is due to the large relative difference between electricity purchase and sell prices (Fig. 5A), which highlights the role of self-consumed PV electricity in value creation.

In the case of electricity prices from 2022 (Fig. 8B and D), the azimuth for maximal *SV* is shifted toward the East, and the contour lines are close to each other, implying that the value of electricity is more sensitive to the panel orientation than with 2019 prices. These characteristics are especially prominent with the Fixed22A pricing scenario because the low purchase price and high selling price encourage maximizing production during the peak spot prices so the excess can be sold with high profits. Since the evening spot price peak occurs so late that there will hardly be PV production, the *SV* is maximized by matching the PV production peak to the morning spot price peak.

The energy productions and SVs of the different [Load profile – PV orientation – Electricity purchase contract] combinations are shown in

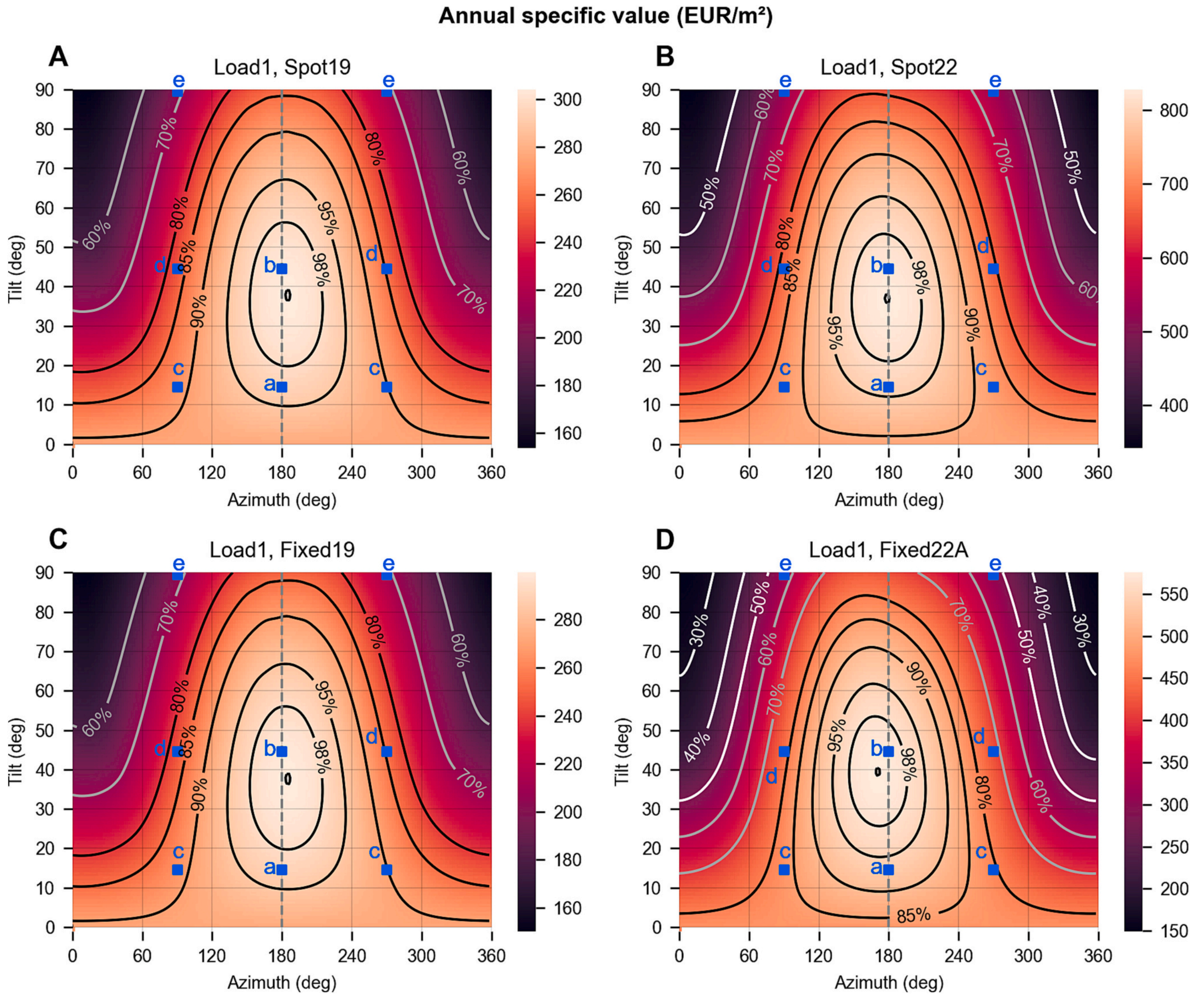

Fig. 8. The SV for Load1 with various MPV systems as a function of tilt and azimuth angles. A: Year 2019 spot prices, maximum value of €304 with azimuth 186° and tilt 38°. B: Year 2022 spot prices, maximum value of €828 with azimuth 178° and tilt 37°. C: Year 2019 fixed contract prices, maximum value of €300 with azimuth 186° and tilt 38°. D: Year 2022 fixed contract A prices, maximum value of €575 with azimuth 170° and tilt 40°. The orientations studied in detail are shown as blue squares. Resolution: 1° for tilt and 2° for azimuth. The labeled blue squares represent the orientation(s) of the PV systems: T15S (a), T45S (b), T15EW (c), T45EW (d), and vertical East- and West-facing surfaces (e). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 5
The total annual electricity production for all PV orientations and the SV of the produced PV electricity for all [Load – Orientation – Contract] combinations for a 4.0 kWp PV system for one year.

Year 2019						Year 2022					
PV	T45S	T45EW	T15S	T15EW	VBPV		T45S	T45EW	T15S	T15EW	VBPV
E (kWh)	3660	2810	3430	3030	4000		3660	2810	3430	3030	4000
SV: Load1 (€)											
Spot19	302	264	293	274	325	Spot22	822	685	794	726	908
Fixed19	298	260	289	270	320	Fixed22A	571	426	537	469	632
						Fixed22B	642	498	610	541	709
SV: Load2 (€)											
Spot19	328	283	315	291	354	Spot22	866	722	834	761	960
Fixed19	305	262	293	270	331	Fixed22A	506	358	470	403	555
						Fixed22B	595	446	560	489	652
SV: Load3 (€)											
Spot19	303	261	291	269	328	Spot22	832	691	801	730	923
Fixed19	284	244	273	252	309	Fixed22A	530	383	496	427	584
						Fixed22B	605	457	571	501	666
SV: Load3F (€)											
Spot19	430	332	403	358	455	Spot22	1010	792	958	856	1100
Fixed19	391	304	367	327	419	Fixed22A	395	300	370	324	443
						Fixed22B	542	418	509	451	595

Table 6
The cost of electricity in one year without any PV production. Load3F is excluded since it is identical to Load3 without PV production.

Electricity cost (€)	Spot19	Fixed19	Spot22	Fixed22A	Fixed22B
Load1	651	652	1330	630	887
Load2	1150	1080	2420	1060	1500
Load3	2090	2050	4000	2010	2810

Table 5. The annual electricity bills without PV for different contracts are shown in Table 6. It should be noted that, with all the studied [Load – Contract] combinations, the order of PV orientations is identical when comparing production and *SV*, i.e., a higher PV production led to a higher value here. This effect was due to the relatively flat electricity price profiles during the daytime (Fig. 5). Although unconventional orientation for MPV increases the production during morning and evening consumption peaks, the price difference compared with that at noon is too small to compensate for lost production. However, when the share of PV in the energy system rises, the electricity price during peak PV production hours will decrease. This phenomenon reduces the difference in the *SVs* of the South-facing and alternative orientations and, if high enough, can shift the optimal point toward the East or West.

With the Spot19 and Fixed19 contracts representing a steady market situation, the main factor affecting the *SV* of the produced PV electricity is the amount of self-consumed electricity. In particular, when comparing the Load3 and Load3F cases, the possibility for demand flexibility allows a vast increase in self-consumption and *SV*. This

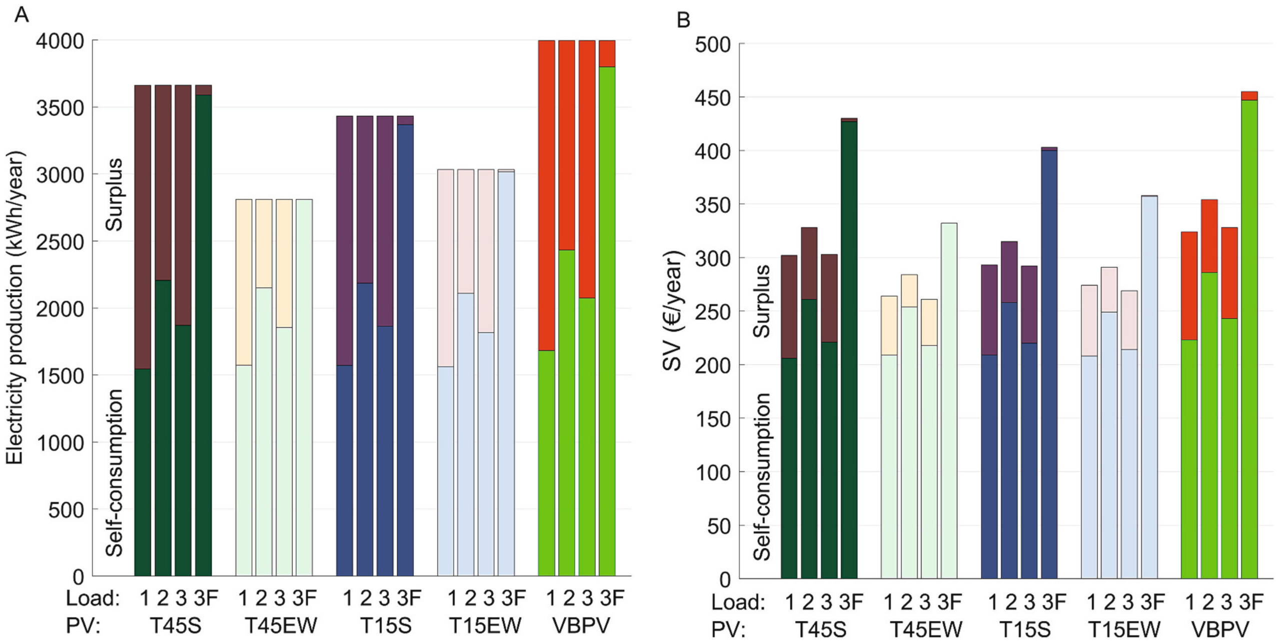

Fig. 9. Total annual electricity production (A) and SV (B) divided into value originating from self-consumed (bottom bar) and surplus (top bar) production for all possible [Load – PV orientation] combinations with the Spot19 contract.

observation is logical due to the low selling price for surplus electricity with the Sell19 contract compared with the total purchase cost with the Spot19 and Fixed19 contracts (Fig. 5). When comparing the Spot19 and Fixed19 contracts, PV has a higher *SV* with the spot price contracts in all cases, although for the Load1 case, the fixed price (6.10 c/kWh) is higher than the average spot price (5.46 c/kWh). However, since PV production focuses on daytime when the spot price is typically higher than the average, the grid electricity replaced by PV production is more expensive with the spot price than with the fixed price.

In 2022, during the energy crisis, the electricity spot price was at an extremely high level, making PV very profitable since the surplus electricity could be sold at a high price (Sell22). In fact, with fixed purchase price contracts made before the crisis, especially Fixed22A, the sell price for surplus PV was frequently higher than the purchase price (although the terms of surplus electricity selling contracts offered to small producers forbid the buying and selling of electricity simultaneously to avoid exploitation, where all PV production is sold and the consumed electricity is bought from the grid). For this reason, when comparing Load2 to Load1, the *SV* with fixed price contracts was lower in all cases since profile Load1 was allowed to sell the PV production that was used for heating with profile Load2. Similarly, when the demand flexibility was added to the profile Load3, the *SV* with fixed price contracts dropped. It was more profitable to heat the house during the night and sell the surplus PV during the day. These cases provided examples of situations where the common rule of thumb, “self-consumed PV electricity is more valuable than sold surplus,” was broken. With the Spot22 contract, this phenomenon was eliminated since both the purchase price and the sell price are bound to the spot price, and, thus, the purchase price is always higher due to transmission and taxes.

When comparing the Spot22, Fixed22A, and Fixed22B contracts, the *SV* is the highest with Spot22 in all cases due to the high value of the grid electricity replaced by self-consumption. However, considering the total electricity cost for the prosumer, the Spot22 was inferior to the Fixed22A and Fixed22B contracts. For example, with the Load1 and T45S profiles, the *SV* was €822 and €571 with Spot22 and Fixed22A contracts, respectively (Table 5), but the corresponding *NCs* (i.e., annual net electricity bills) were €511 and €59. Thus, the prosumer with the Fixed22A contract is a clear winner, although the PV system reduces economic loss due to unfavorable electricity purchase contracts for the prosumer with the Spot22 contract.

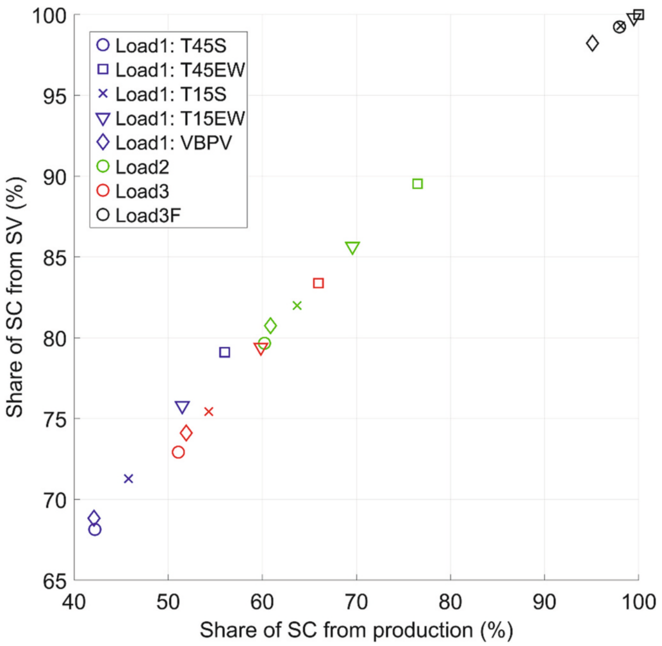

Fig. 10. Share of self-consumption from production and SV for all studied [Load – PV orientation] combinations with the Spot19 contract. Different PV orientations are differentiated with symbols, as shown in the legend for Load1. For simplicity, the full legend is not shown. For the meaning of the symbols, refer to the legend for Load1.

A detailed breakdown of the production and *SV* into self-consumption and selling surplus is shown in Fig. 9 as a bar chart and in Fig. 10 as a scatter plot. For the value calculations, data are shown for the Spot19 (and Sell19 for electricity selling) contract only. This contract was chosen from the five contracts studied since it represents a steady market situation, and the dynamic pricing nature is included in both purchase and sell contracts. The role of self-consumption in value creation is highlighted. For all the 20 cases shown, the share of self-consumption in the production (Fig. 9A) is significantly smaller than the share of self-consumption in *SV* (Fig. 9B). Fig. 10 displays that this difference is highest for cases with the lowest share of self-consumed production. When comparing the MPV systems with different orientations, the *SV* from self-consumption is almost identical for Loads1–3 when the load is fixed and the orientation is changed. The main difference in *SV* comes from the higher amount of surplus value for the systems that produce more electricity. When comparing the *SV* with different loads, the loads that allow high SC (especially Load3F, followed by Load2) have the highest *SV*.

Conventional daily scheduling for electricity load in a house with flexible electric heating, represented by Load3, matches poorly with the PV production: the flexible heat demand is scheduled for nighttime when the national electricity consumption is low. Thus, although the electricity demand is massive (19,000 kWh/year), the potential to use their own PV production is low. However, when the heat demand is satisfied during the daytime when surplus PV is available (Load3F), PV becomes very profitable.

In conclusion, with identical MPV panels having different orientations, the orientation that produces the most electricity (T45S) has the highest *SV*. However, when orientation is changed away from the optimal, the difference in *SV* is smaller than the difference in production due to higher relative self-consumption. This phenomenon reduces the economic losses due to non-optimal orientation, broadening the possibilities to install PV in locations where the orientation is determined by the surroundings, such as rooftops. Moreover, a further increase in self-consumption by utilizing energy sharing in peer-to-peer energy communities [36] enables efficient use of differently oriented rooftops for high-value PV production.

As Fig. 9 shows, VBPV has superior *SV* with all loads due to higher overall production and production profile that allows higher absolute self-consumption than MPV. From an economic aspect, favoring VBPV over MPV is beneficial if the price difference between bifacial and monofacial panels is smaller than the difference in *SV*. However, unlike MPV, which can be installed parallel to a tilted roof, finding suitable installation sites for VBPV in a built environment requires creative thinking from an architectural perspective. Some examples have been given in our previous work [11]. Dual use of the land area, such as installing VBPV to serve as fences to locations that have little to no shading, is an attractive option. The importance of the feasible use of VBPV is likely to increase in the future. Currently, electricity is cheaper in Finland around noon compared with the morning and evening, and this difference is expected to grow in the next few years as the (South-facing) PV production capacity increases and dampens the electricity price around noon.

3.3. Sensitivity analysis for system size

To analyze the effect of system size, the annual production and *SV* of PV electricity, divided into self-consumption and surplus, with two orientations (T45S and VBPV) and one pricing scenario (Spot19), are shown in Fig. 11. The motivation for showing these scenarios was to compare the VBPV system with the best-performing MPV system in a market scenario that represents a normal situation instead of an energy crisis. The spot price was chosen for electricity purchase instead of a fixed price since both the purchase and selling prices of PV electricity are

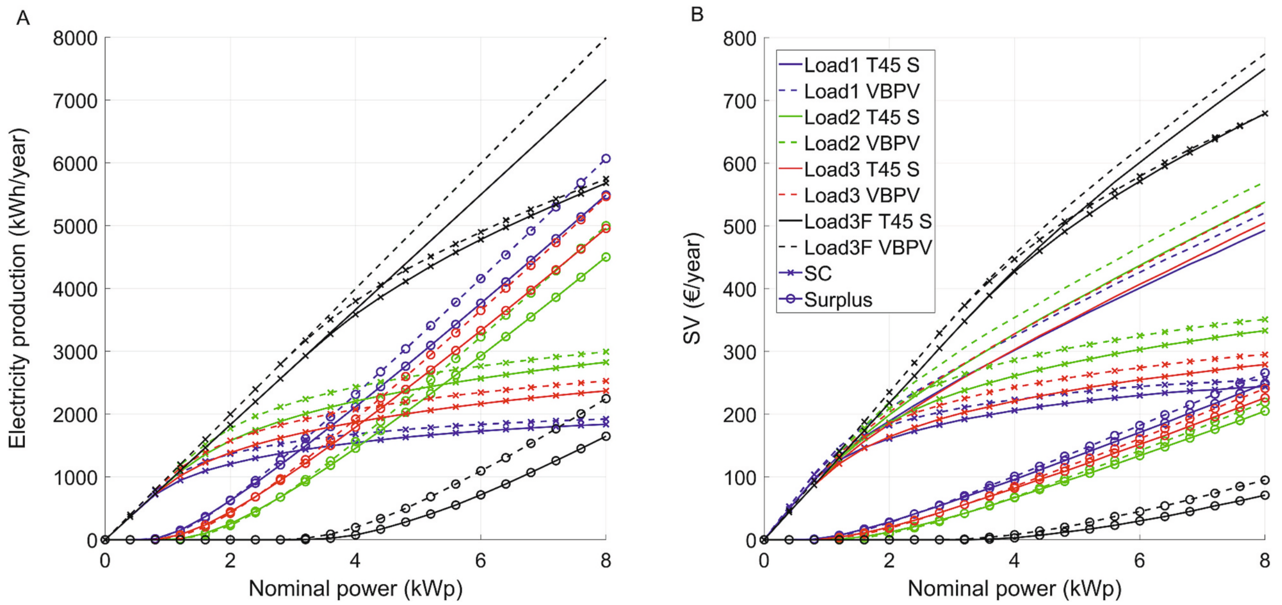

Fig. 11. The annual electricity production (A) and SV with the Spot19 contract (B) as functions of system nominal power. For each datapoint, the total, self-consumed, and surplus productions (A) and SVs (B) are shown. For simplicity, the full legend is shown only for the total production or SV. The datapoints for self-consumption are marked with "x" and the datapoints for surplus with "o"; for the meaning of the colors and solid/dashed line, the reader is referred to the legend for the total production or SV. Note that the legend is common for (A) and (B). In (A), the total production curves for different loads overlap completely, and the curves for Loads1–3 are hidden behind the curves for Load3F.

bound to the same main component (Nord Pool spot price for Finland).

For Loads1–3, when the size of the PV system is increased, the amount of self-consumed PV electricity starts to saturate between 1 and 2 kWp system nominal power (Fig. 11A). When more panels are added to the system, most of the additional production is sold to the grid. Thus, the added economic value is low since, with this pricing scenario, the sell price is always significantly lower than the purchase price (Fig. 5A). Thus, the increase of *SV* as a function of nominal power is significantly slower (Fig. 11B) compared with the production (Fig. 11A) when the nominal power exceeds 2 kWp.

However, for Load3F, the possibility for a temporal shift of the heavy heating load enables the consumption of almost all produced PV electricity for systems with nominal power below 4 kWp (Fig. 11A), which allows rapid linear increase for the *SV* (Fig. 11B). Even beyond 4 kWp nominal power, most of the added production is self-consumed. Thus, the increase of *SV* as a function of system nominal power remains steeper than with other load profiles. These observations highlight that, at least in a steady market situation, the additional value created when increasing the size of the PV system is highly dependent on the possibility of consuming the additional energy at the spot. This observation may create an incentive to keep the size of the PV system relatively small when the demand during the peak production hours is low and large-scale load-shifting is unfeasible. However, when considering economic feasibility in real cases, the costs occurring from other sources than solar panels, such as inverters, installation, and supporting structures, must be included. Generally, the total price of a PV power plant per kilowatt peak is lower for larger systems. Thus, although the last added panel creates the least additional value, it also often creates the least additional cost.

For all the studied load cases, the VBPV system had higher production and SV than the T45S system with the same nominal power. Thus, the increase in SV when using VBPV instead of T45S is mainly due to increased production. The improved temporal match between PV production and electricity load profiles with VBPV allowed a slight increase in self-consumption, maintaining the advantage gained by higher production.

The differences in the production profiles between T45S and other MPV systems are smaller than between T45S and VBPV (Fig. 3). Thus, the key observations based on Fig. 11, the improved performance of VPBV compared with MPV and the importance of load flexibility for systems with high nominal power, are valid for other MPV systems as well. However, as the PV production capacity increases in Finland, the electricity price during the summer months around noon is expected to decrease, which dampens the SV of the T45S system and other MPV systems, where electricity production peaks around noon. This effect can change drastically the observations calculated based on 2019 pricing data, where the effect of PV production on the electricity price is negligible. Finally, the analysis presented here assumes that suitable installation sites for all necessary panels are found from the target house: 1 kWp requires approximately 5 m^2 of panel area. With MPV, this is a realistic assumption for a house with a large, south-facing roof and without any tall, shading objects in the immediate proximity of the panels. With VBPV, however, fitting 40 m^2 or even 20 m^2 into a single plot can be challenging. To work ideally, VBPV requires a shade-free location where it can be installed as a fence. Finding such locations in an urban environment requires creativity and novel architectural solutions. This aspect, however, is outside the scope of this study and is therefore excluded. Coming back to the economic aspects, since VBPVs have more limitations on where to install them in urban settings, they are less likely to suffer from self-cannibalization compared with MPV systems. Thus, one key issue of this work is that VBPV should be favored instead of MPV if a suitable location can be found since VBPV systems already outperform the conventional MPV, and this gap is likely to increase in the future.

Table 7
Real purchase costs of certain 3.5–5 kWp PV systems in Finland, as expressed by the retailers. All packages include solar panels, inverter, and installation equipment.

Retailer	Size (kWp)	Price (€)	Installation	Ref
Mr. LVI	3.6	4790	No	[40]
Aurinkopaneelikauppa.fi	4.5	4990	No	[41]
Lämpöpartio	4.56	4999	No	[42]
Lämpöpartio	4.92	8699	Yes	[39]
Tenvoltti Oy	4.10	5340	Yes	[43]

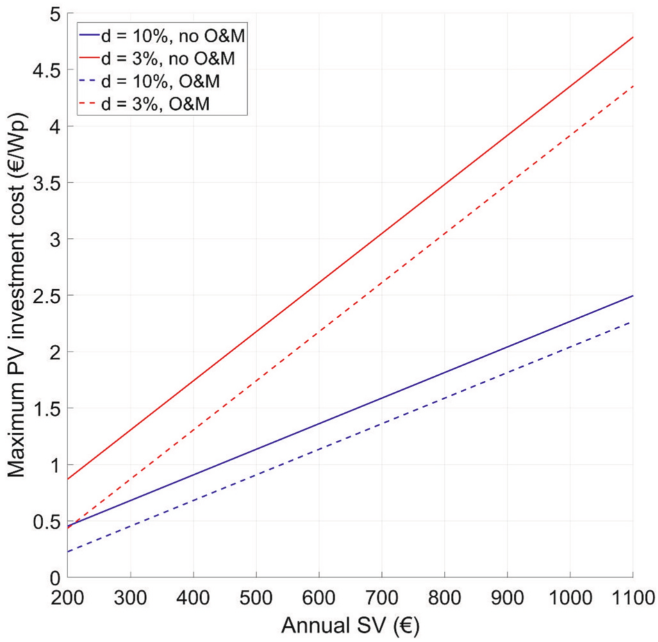

Fig. 12. The maximum allowed investment cost to reach a positive NPV as a function of the annual SV of a 4 kWp PV system.

3.4. Economic feasibility of the case study systems

According to Motiva Oy [37], the typical cost for a 5 kWp PV system in Finland containing the panels and needed accessories was €5000–7000 in 2021. Table 7 presents the purchase costs for certain PV systems with nominal power between 3.5 and 5.0 kWp systems in Finland in August 2023 from four different retailers. The current retail prices for an approximately 4 kWp PV system and accessories (inverter, mounting racks, etc.) are mostly below €5000, but the installation can be expensive and should be bought as a professional service. Finnish legislation requires professional qualifications for persons installing PV systems. One Finnish retailer, Aurinkomaailma, reported the average costs of a PV system to be €1.82/Wp for a 3.24 kW system and €1.23/Wp for a 6.5 kWp system [38] including installation, whereas Lämpöpartio is selling a 4.92 kWp system, including all accessories and installation, at €8699 (€1.77/Wp) [39]. Overall, the installation cost is case-specific for residential customers and depends heavily on the location of the house, the material of the roof, the local competition situation between different contractors, and other factors. Thus, for further calculations, we assume a 4 kWp PV system and find the maximum investment cost for it to be profitable.

The maximum allowed investment cost (€/Wp) enabling a positive *NPV* for the PV system is calculated as a function of the annual *SV* of electricity produced by a 4 kWp PV system (Fig. 12). Different scenarios included discount factors of 10% (representing cases where the house owner has other highly profitable investment options that compete with PV) and 3% (representing cases where the alternative for investing in PV is saving money in the bank). The expected lifetime of the systems was set to 25 years, which is a common power warranty period for solar panels. In real applications, the operation and maintenance (O&M) costs should also be included. However, the exact O&M costs depend heavily on the location, type of panels, and the amount of work that the house owner does independently. Thus, the exact general value for O&M costs is unavailable. In this study, the results are shown without any O&M costs and with O&M costs of €100/year. Since the effect of discounting is applied identically to both *SV* and O&M costs (Eq. (21)), the threshold value to reach positive *NPV* for any O&M cost level can be calculated by determining the *SV* from Fig. 12 without O&M costs and then adding the wanted O&M value to the *SV*.

Without O&M costs, the smallest annual *SVs* to enable positive *NPVs* were €794 and €414 for $d = 10\%$ and $d = 3\%$, respectively, when an investment cost of €1.80/Wp is assumed. In an optimistic scenario, an investment cost of €1.20/Wp had corresponding values of €529 and €276 for $d = 10\%$ and $d = 3\%$, respectively. When the O&M costs are added to the analysis, the required *SVs* are increased by the exact amount of the annual O&M cost.

When comparing the threshold values in Fig. 12 to the calculated *SVs* in Table 5, the key observation is that, with 2019 data, only the house with Load3F was able to reach sufficient *SVs* for economically feasible operation if $d = 3\%$ was used. However, with 2022 data and spot price electricity contract, even the lowest *SV* (€682 with Load1 and T45EW) was highly profitable with $d = 3\%$ and close to the realistic profitability threshold with $d = 10\%$. This highlights that the profitability of PV is highly vulnerable to the market situation, that is, with a high electricity price, PV is profitable even with assumptions strongly unfavorable to PV (high *d*), whereas with a steady and low electricity price, even the PV-favoring assumptions ($d = 3\%$, no O&M costs) require very low investment cost to reach positive *NPV*.

For VBPV, the exact price difference compared with MPV depends on the location, year, installation, and source. Rodriguez-Gallegos et al. [44] compared the costs of MPV and BPV technologies worldwide and, based on the values shown for locations relevant to Finland (Estonia and Germany), BPV was 6–8% more expensive than MPV. This is in the same range as the variation in *SV* between the VBPV and best MPV system for the different [Load – Contract] cases shown in Table 5. The variation range was 7.4–10.9%. However, several factors affect this price difference, including the drop in costs for (relatively novel) BPV technology, the need for supporting structures for vertical installations, and, especially in the case of single households, the current availability of different panels offered by the local contractors. Thus, for a small-scale prosumer, the likely increase in price when going bifacial is case-dependent.

4. Conclusions

The economic value of produced PV electricity, denoted here as *SV*, for one year was determined for a large variety of case studies representing detached houses with their own PV installations: five PV orientations, five electricity purchase contracts, and four electricity load profiles. Overall, maximizing the amount of self-consumed solar electricity was the most profitable strategy. When PV electricity is consumed on the spot, the value is equal to the avoided cost of buying electricity, which includes the transmission fees and taxes. With the 2019 electricity price data (steady market situation), this effect was clear: a 23.2% reduction in production resulted in only a 12.6% reduction in *SV* when the amount of self-consumed PV electricity was similar. However, with 2022 price data (energy crisis), selling surplus production was very profitable due to the high electricity spot price.

The *SV* of the produced PV electricity as a function of system size increased rapidly if most of the added production was self-consumed. When the self-consumption saturated and most of the added production was sold, the increase of *SV* was slower. Thus, when designing a PV system for a detached house, the self-consumption potential is a crucial factor. If the hot water is heated with electricity (Load3F), the self-consumption is almost 100%, with a 4 kWp PV system throughout the year. Besides economic benefits, the increased self-consumption reduces the need for battery storage and improves the sustainability, energy security, and resilience of the system. However, the total cost of a PV system also includes certain fixed costs, such as installation and an inverter, which form a higher share of the total cost for small systems. The profitability of a PV system during its lifetime, determined by its *NPV*, depends strongly on the discount factor used. As expected, the electricity market situation has a high effect on the competitiveness of PV. With high electricity market prices, such as in 2022, the *SVs* for PV systems are large enough to achieve positive *NPV* for the project, but the situation was different in 2019.

VBPV was shown to have superior *SV* over MPV in all cases: 9.1% higher overall production and 7.4–10.9% higher *SV* compared with T45S, which allows covering increased investment costs. This highlights the suitability of VBPV in Nordic conditions due to the increased total electricity production. The improved temporal match between PV production and load achieved with VBPV played only a minor role in the current electricity price. In the near future, when PV becomes a more significant electricity source even at high latitudes, thus dampening the electricity price around noon, VBPV allows for avoiding the price valley around noon and reaping the high electricity prices during summer mornings and evenings.

A key challenge for VBPV is the limited number of suitable installation sites. Whereas MPV panels can be installed easily and conveniently on a tilted roof, integrating VBPV panels effectively in a built environment is more challenging. Creative solutions for the dual use of land, such as utilizing VBPV panels as fences, are necessary to boost this attractive technology. To utilize the potential of VBPV and encourage residential producers to install VBPV panels, there is a need to define how large VBPV systems can be installed in urban areas and where the panels should be placed, considering both electricity production and disturbance to other land use.

Finally, since the price data used here were from Finland from 2019 and 2022 when the share of PV in the total electricity generation was low (few per mils), the cannibalization effect, i.e., the decrease of the electricity price due to high PV production, is negligible. However, as PV production in Finland is increasing rapidly, this phenomenon becomes more significant with PV in Finland, as it has already happened with wind power in Finland and PV in Germany, among others. Thus, within a few years, on summer days around noon, the electricity price is expected to lower significantly, reducing the value of electricity produced by South-facing PV. For VBPV, the production peaks occur during the high consumption and high price hours, reducing the risk of cannibalization, especially if the South-facing installation remains the dominating installation type. Thus, the solutions that allow higher PV production during morning and evening, such as the already well-performing VBPV and unconventionally orientated MPV, are expected to perform economically better compared with the South-facing MPV in the future than their current performance.

The work was funded by Finnish Cultural Foundation (SJ, KM), Emil Aaltonen Foundation (SJ), Research Council of Finland, project 336577 (KM) and Strategic Research Council 358542 (LK).

CRediT authorship contribution statement

S. Jouttijärvi: Writing – original draft, Visualization, Validation, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **L. Karttunen:** Writing – original draft, Visualization, Validation, Resources, Methodology, Investigation, Formal analysis, Conceptualization. **S. Ranta:** Writing – original draft, Resources, Methodology, Data curation. **K. Miettunen:** Writing – original draft, Supervision, Project administration, Funding acquisition, Conceptualization.

Declaration of competing interest

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

Data availability

Data will be made available on request.

References

[1] Nord Pool AS. https://www.nordpoolgroup.com/en/2023 [accessed August 01 2023].

[2] Biber A, Tunçinan M, Wieland C, Spliethoff H. Negative price spiral caused by renewables? Electricity price prediction on the German market for 2030. Electricity J 2022;35:107188. https://doi.org/10.1016/J.TEJ.2022.107188.

[3] Tselika K. The impact of variable renewables on the distribution of hourly electricity prices and their variability: a panel approach. Energy Econ 2022;113:106194. https://doi.org/10.1016/J.ENECO.2022.106194.

[4] Kolb S, Dillig M, Plankenbühler T, Karl J. The impact of renewables on electricity prices in Germany - an update for the years 2014–2018. Renew Sustain Energy Rev 2020;134:110307. https://doi.org/10.1016/J.RSER.2020.110307.

[5] Tanaka K, Matsumoto K, Keeley AR, Managi S. The impact of weather changes on the supply and demand of electric power and wholesale prices of electricity in Germany. Sustain Sci 2022;17:1813–25. https://doi.org/10.1007/s11625-022-01219-7.

[6] Gomez-Exposito A, Arcos-Vargas A, Gutierrez-Garcia F. On the potential contribution of rooftop PV to a sustainable electricity mix: the case of Spain. Renew Sustain Energy Rev 2020;132:110074. https://doi.org/10.1016/J.RSER.2020.110074.

[7] Olczak P, Komorowska A. An adjustable mounting rack or an additional PV panel? Cost and environmental analysis of a photovoltaic installation on a household: a case study in Poland. Sustain Energy Technol Assess 2021;47:101496. https://doi.org/10.1016/J.SETA.2021.101496.

[8] Gul E, Baldinelli G, Bartocci P, Bianchi F, Domenighini P, Cotana F, et al. A techno-economic analysis of a solar PV and DC battery storage system for a community energy sharing. Energy 2022;244:123191. https://doi.org/10.1016/J.ENERGY.2022.123191.

[9] Böök H, Poikonen A, Aarva A, Mielonen T, Pitkänen MRA, Lindfors AV. Photovoltaic system modeling: a validation study at high latitudes with implementation of a novel DNI quality control method. Solar Energy 2020;204:316–29. https://doi.org/10.1016/j.solener.2020.04.068.

[10] European Commission. https://re.jrc.ec.europa.eu/pvg_tools/en/; 2023 [accessed September 07 2023].

[11] Jouttijärvi S, Lobaccaro G, Kamppinen A, Miettunen K. Benefits of bifacial solar cells combined with low voltage power grids at high latitudes. Renew Sustain Energy Rev 2022;161:112354. https://doi.org/10.1016/J.RSER.2022.112354.

[12] Guo S, Walsh TM, Peters M. Vertically mounted bifacial photovoltaic modules: a global analysis. Energy 2013;61:447–54. https://doi.org/10.1016/j.energy.2013.08.040.

[13] Nordpool. https://www.nordpoolgroup.com/en/Market-data1/Dayahead/Area-Prices/ALL1/Yearly/?view=table; 2023 [accessed September 07 2023].

[14] Rhodes JD, Upshaw CR, Cole WJ, Holcomb CL, Webber ME. A multi-objective assessment of the effect of solar PV array orientation and tilt on energy production and system economics. Solar Energy 2014;108:28–40. https://doi.org/10.1016/J.SOLENER.2014.06.032.

[15] Litjens GBMA, Worrell E, van Sark WGJHM. Influence of demand patterns on the optimal orientation of photovoltaic systems. Solar Energy 2017;155:1002–14. https://doi.org/10.1016/J.SOLENER.2017.07.006.

[16] Meriläinen A, Puranen P, Kosonen A, Ahola J. Optimization of rooftop photovoltaic installations to maximize revenue in Finland based on customer class load profiles and simulated generation. Solar Energy 2022;240:422–34. https://doi.org/10.1016/J.SOLENER.2022.05.057.

[17] Sadineni SB, Atallah F, Boehm RF. Impact of roof integrated PV orientation on the residential electricity peak demand. Appl Energy 2012;92:204–10. https://doi.org/10.1016/J.APENERGY.2011.10.026.

[18] Brown PR, O'Sullivan FM. Shaping photovoltaic array output to align with changing wholesale electricity price profiles. Appl Energy 2019;256:113734. https://doi.org/10.1016/J.APENERGY.2019.113734.

[19] Hartner M, Ortner A, Hiesl A, Haas R. East to west – the optimal tilt angle and orientation of photovoltaic panels from an electricity system perspective. Appl Energy 2015;160:94–107. https://doi.org/10.1016/J.APENERGY.2015.08.097.

[20] Litjens GBMA, Worrell E, van Sark WGJHM. Influence of demand patterns on the optimal orientation of photovoltaic systems. Solar Energy 2017;155:1002–14. https://doi.org/10.1016/J.SOLENER.2017.07.006.

[21] Chudinzow D, Nagel S, Güsewell J, Eltrop L. Vertical bifacial photovoltaics – a complementary technology for the European electricity supply? Appl Energy 2020;264:114782. https://doi.org/10.1016/J.APENERGY.2020.114782.

[22] Jouttijärvi S, Thorning J, Manni M, Huerta H, Ranta S, Di Sabatino M, et al. A comprehensive methodological workflow to maximize solar energy in low-voltage grids: a case study of vertical bifacial panels in Nordic conditions. Solar Energy 2023;262:111819. https://doi.org/10.1016/J.SOLENER.2023.111819.

[23] Jouttijärvi S, Tok M, Karttunen L, Huerta Medina H, Ranta S, Miettunen K. Modeling and measuring the power output of vertical bifacial solar panels in Nordic conditions. In: 8th World Conference on Photovoltaic Energy Conversion; 2022. p. 507–11. https://doi.org/10.4229/WCPEC-82022-3BO.14.2.

[24] Ranta S, Stein JS, Whitney E, Huerta H, Heinonen A. Self-consumption rate achieved by the bifacial East-West vertical PV system compared to the conventional South-facing system in Nordic conditions. In: 36th EUPVSEC; 2020. https://doi.org/10.4229/EUPVSEC20192019-6CO.15.5.

[25] Stein JS, Holmgren WF, Forbess J, Hansen CW. PVLIB: Open source photovoltaic performance modeling functions for Matlab and Python. In: Conference record of the IEEE photovoltaic specialists conference. vols. 2016. November, Institute of Electrical and Electronics Engineers Inc.; 2016. p. 3425–30. https://doi.org/10.1109/PVSC.2016.7750303.

[26] Starke AR, Lemos LFL, Barni CM, Machado RD, Cardemil JM, Boland J, et al. Assessing one-minute diffuse fraction models based on worldwide climate features. Renew Energy 2021;177:700–14. https://doi.org/10.1016/J.RENENE.2021.05.108.

[27] Beck HE, Zimmermann NE, McVicar TR, Vergopolan N, Berg A, Wood EF. Present and future Köppen-Geiger climate classification maps at 1-km resolution. Sci Data 2018;5:1–12. https://doi.org/10.1038/sdata.2018.214.

[28] Utrillas MP, Martinez-Lozano JA. Performance evaluation of several versions of the Perez tilted diffuse irradiance model. Solar Energy 1994;53:155–62. https://doi.org/10.1016/0038-092X(94)90476-6.

[29] Huld T, Friesen G, Skoczek A, Kenny RP, Sample T, Field M, et al. A power-rating model for crystalline silicon PV modules. Solar Energy Mater Solar Cells 2011;95: 3359–69. https://doi.org/10.1016/j.solmat.2011.07.026.

[30] King DL, Boyson WE, Kratochvil JA. Photovoltaic array performance model. 2004. https://doi.org/10.2172/919131.

[31] Sun X, Khan MR, Deline C, Alam MA. Optimization and performance of bifacial solar modules: a global perspective. Appl Energy 2018;212:1601–10. https://doi.org/10.1016/j.apenergy.2017.12.041.

[32] Solis Inverters. https://www.solisinverters.com/4g_3p_inverter_lv/34617.html; 2023 [accessed September 26 2023].

[33] Growatt. https://www.growatt-inverter.com/product/mod-6000-tl3-x-on-grid-6kw-2-mppt-3-phase/; 2023 [accessed September 26 2023].

[34] Mutanen A, Lummi K, Pertti J. Valtakunnallisten tyyppikäyttäjämäärittelyiden päivittäminen ja hyödyntämisen periaatteet verkkopalvelumaksuihin liittyvissä tarkasteluissa (Engl. Updating the national type user definitions and the principles of their utilization in the power grid service fee examinations). Tampereen yliopisto 2019:22–6.

[35] Energy Authority. https://energiavirasto.fi/sahkon-hintatilastot; 2023 [accessed August 01 2023].

[36] Tushar W, Yuen C, Saha TK, Morstyn T, Chapman AC, Alam MJE, et al. Peer-to-peer energy systems for connected communities: a review of recent advances and emerging challenges. Appl Energy 2021;282:116131. https://doi.org/10.1016/J.APENERGY.2020.116131.

[37] Motiva. https://www.motiva.fi/ratkaisut/uusiutuva_energia/aurinkosahko/jarjestelman_valinta/aurinkosahkojarjestelmien_hinta; 2023 [accessed August 10 2023].

[38] Aurinkomaailma. https://aurinkomaailma.fi/aurinkopaneelien-hinta/; 2023 [accessed November 23 2023].

[39] Lämpöpartio. https://kauppa.lampopartio.fi/tuote/aurinkovoimala-492-kwp-asennettuna/; 2023 [accessed August 10 2023].

[40] LVI Mr. https://www.varaaja.com/index.php/aurinkosahko/aurinkosahkojarjestelmat-fronius/aurinkosahkojarjestelma-scanoffice-premium-3-54-kwp-fronius; 2023 [accessed August 10 2023].

[41] Aurinkopaneelikauppa.fi. https://www.aurinkopaneelikauppa.fi/Solis-Aurinkovoimala-37kW; 2023 [accessed August 10 2023].

[42] Lämpöpartio. https://kauppa.lampopartio.fi/tuote/aurinkovoimala-456-kw/; 2023 [accessed August 10 2023].

[43] Oy Tenvoltti. https://www.tenvoltti.fi/hinnasto/; 2023 [accessed August 10 2023].

[44] Rodríguez-Gallegos CD, Bieri M, Gandhi O, Singh JP, Reindl T, Panda SK. Monofacial vs bifacial Si-based PV modules: which one is more cost-effective? Solar Energy 2018;176:412–38. https://doi.org/10.1016/j.solener.2018.10.012.