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D1.3 Assessment of current and future grid financing challenges in a highly distributed power system and opportunities and threats to PV business models with high PV penetration

T1.3 Specifications on future technical and financial challenges related with high PV penetration

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Executive Summary

In this deliverable, a prospective analysis is conducted, assessing the financial challenges that could arise in case of a high penetration of PV in electricity grids, under various assumptions (e.g., PV penetration level, type of PV system considered, type of grid tariffs applied, ...). The financial challenges are assessed by evaluating the potential impacts on the cash flows (positive or negative) of two key stakeholders: (1) **grid operators** and (2) **PV systems' operators/owners**.

First, the **impact of higher PV penetration rates on revenues for grid operators is assessed**.

Higher PV penetration rates across electricity consumers, increase the number of electricity consumers which can do self-consumption thus increasing their sufficiency and reducing the net amount of electricity they would withdraw from the grid. Under volumetric grid tariffs which are currently the most used grid tariff design in the studied countries, this reduction in volume taken from the grid could impact the revenues associated with grid tariffs collection. Nevertheless, regardless of the considered time horizon (2025 and 2030), the PV penetration scenario (BaU or ZE_2050) and most importantly the network tariff design, the revenues associated to the collection of network tariffs increase compared to the 2022 base case when electrification scenario (high or low) are factored in. This indicates that the revenue losses due to the decrease in net electricity consumption through wider presence of prosumers is largely compensated by the revenue gains linked to the increase in electricity consumption through the wider electrification of mobility and heating needs. Therefore, from the grid operators' perspective, energy-based tariffs do not appear as a threat for grid operators' revenues in a context of higher PV penetration but rather as an adequate frame to seize the opportunity of electrification of heating and mobility needs.

Then, the **impact of higher PV penetration rates on PV profitability is assessed**. For this, wholesale electricity prices are modelled using Python and following a mean-reverting and jump-diffusion process.

For distributed PV systems, there is very limited dependence to hourly wholesale electricity market price variation. On the contrary other elements which are not a direct consequence of higher PV penetration rates but are bound to evolve as the PV market develops are taken into account in the analysis. These are considered business model (feed-in tariff, investment premium, unsubsidized) and network tariff design. Under energy-based network tariffs, PV systems with high self-consumption rates are a no brainer from an economic point of view even with retail electricity prices at their early 2020 level and even under an unsubsidized business model. Indeed, under this business models, self-consumption rates above 40% for the locations with the poorest irradiation conditions (900 kWh/m².a) and above 10% for the locations with the best irradiation conditions (2100 kWh/m².a) are sufficient to achieve break-even under energy-based network tariffs. Under capacity-based network tariffs, due to the reduced economies on the electricity bill potential, higher self-consumption rates are required to reach the same level of competitiveness. Sensitivity analysis is conducted on commodity prices and on PV system prices, showing how under higher end-user electricity prices (1) PV profitability is multiplied and (2) the negative impact of higher PV system prices can be compensated.

For centralized PV systems, there is high dependence to hourly wholesale electricity market price variation. In addition, other elements, which are not a direct consequence of higher PV penetration rates but are bound to evolve as the PV market develops, are taken into account in the analysis. These are considered business model (different shares of the PV production valued through a fixed-price PPA and through merchant PV model) and PV system orientation. As far as system orientations are concerned, it appears that the negative impact of the east and west orientations (lower annual production compared to the south-oriented PV system) outweighs the potential positive impact which is to be exposed to the prices earlier in the morning and later in the afternoon which are on average higher. Then, sensitivity analysis to different parameters evolution (selling price increase/decrease, PPA price decrease, CAPEX increase/decrease, number of negative hour occurrence increase) are conducted. These demonstrate that in general one of these positive trends (e.g., rising selling prices, CAPEX decrease) can typically compensate for a negative trend (e.g., rising PV system prices, declining selling prices, declining PPA prices).

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1 ABOUT THIS REPORT

1.1 Description of the deliverable content and purpose

In Task 1.3, a prospective analysis is conducted, assessing the financial challenges that could arise in case of a high penetration of PV in electricity grids, under various assumptions (e.g., PV penetration level, type of PV system considered, type of grid tariffs applied, ...). This has been specifically assessed by evaluating the potential impacts on the cash flows (positive or negative) of two key stakeholders: (1) **grid operators** and (2) **PV systems' operators/owners**. The assessment is done considering an increase in the electrification for DSOs

1.2 Reference material

NA

1.3 Relation with other activities in the project

Connections between Task 1.3 and Tasks 1.7, 6.2 and 2.5 exist.

In Task 1.3 a prospective analysis is conducted, assessing the financial challenges that could arise in case of future high penetration of PV in electricity grids, under various assumptions (e.g., PV penetration level, type of PV system considered, type of grid tariffs applied, ...). This will be specifically assessed by evaluating the potential impacts on the cash flows (positive or negative) of two key stakeholders: (1) grid operators and (2) PV systems' operators/owners.

Task 1.7 looks at the roadmaps to achieve high PV penetration levels in the EU and most promising scenarios. An alignment about the targets for the PV penetration has been done according to the work done by the team responsible for T1.7.

In Task 6.2, economic and legal constraints that prevent the design of profitable business models, thereby hindering the realisation of the ambitioned high PV penetration, have been identified and analysed, as of today. Country differences have been highlighted. Recommendations to lift-up the identified obstacles have also been produced.

In Task 2.5, modern finance and risk modelling (technical and non-technical) applied to PV systems and portfolios is addressed.

Thus, overall, there is a good complementarity in terms of types of constraints/risks/challenges tackled in these tasks (financial, market, economic, legal, technical and non-technical), in terms of point of view taken (single PV project, PV project portfolio, grid actors) as well as in terms of time horizon (current (prior to high PV penetration rates), future (following different PV penetration pathways or scenarios)). Key connections, complementarity and differences between Tasks 1.3, 6.2 and 2.5 are summarized in Table 1-1.

Table 1-1 - Key connections, complementarity and differences between Tasks 1.3, Task 6.2 and Task 2.5

	Task 1.3	Task 6.2	Task 2.5
Type of constraints/risks/challenges studied	Financial and market	Economic and legal	Technical (focus) and non-technical (building on other tasks' results)
Time horizon considered	Current up to 2030	Current and very short-term	-
Approach	Prospective	Descriptive	-
Perspective taken	Grid & PV	PV	PV

1.4 Abbreviation list

Table 1-2 - Abbreviation list

Abbreviation	Meaning
BaU	Business as Usual
BC	Base Case
CAPEX	Capital Expenditure
CPP	Critical Peak Pricing
DSO	Distribution system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
ESCOs	Energy service companies
EV	Electric vehicle
FU	Full unbundling
GHG	Greenhouse Gas
HP	Heat pump
ICE	Internal Combustion Engines
IRR	Internal Rate of Return
ISO	Independent system operator
ITO	Independent transmission operator
KPI	Key Performance Indicator
LCOE	Levelized Cost of Electricity
LUT	Lappeenranta-Lahti University of Technology LUT, Finland
MIRR	Modified Internal Return Rate
NPV	Net Present Value
NRA	National Regulatory Agency
OPEX	Operational Expenditure
OU	Ownership unbundling
PPA	Power Purchase Agreement
PV	Photovoltaics
SC	Self-consumption
ToU	Time of Use
TSO	Transmission system operator
ZE_2040	Zero Emissions reached in 2040 scenario
ZE_2050	Zero Emissions reached in 2050 scenario

2 INTRODUCTION

In this deliverable, the question of grid financing and PV profitability under different PV penetration and electrification scenarios is assessed. For this purpose, a risk inventory for grid operators' revenues (grid operators' costs are excluded from the scope of this deliverable) and PV profitability was established. Then risks which are impacted by higher PV and electrification penetration rates were identified and constitute the core of the deliverable. In particular these risks were qualitatively and quantitatively described and assessed.

Given the prospective aspect of the work presented in this deliverable, the various assessments are not conducted for some countries specifically rather they aim at being representative of different situations in Europe. Therefore, when relevant the calculations have been conducted taking different boundary conditions (irradiation, business models, self-consumption rates, …). Nevertheless, some national quantitative or qualitative insights are provided throughout the document.

The time scope primarily considered runs from 2022 to 2030 and is largely based on PV penetration scenarios established by LUT and concerning this timeframe. However, when assessing the PV profitability of PV projects starting in 2030 with an assumed system lifetime of 30 years, additional assumptions were made until 2060.

The work presented in this report is based on various sources and data. Literature research was conducted, and partners involved in this task have contributed by sharing qualitative and quantitative feedback on the specific data as well as on the general structure and content of this deliverable. Finally, external sources and datasets have been used.

3 GRID FINANCING AND PV PROFITABILITY MECHANISMS & PRINCIPLES

3.1 PV PROFITABILITY

The profitability of PV systems is strongly affected by diverse factors: the PV performance, the PV costs and the business models. Parameters such as Capital Expenditure and Operational Expenses, typically referred to as CAPEX and OPEX, provide a direct indication on the cost-competitiveness of PV installations. However, they are not sufficient to give a holistic overview on the profitability of the system. Parameters such as the Levelized Cost of Electricity (LCoE) or the Net Present Value (NPV) and the Internal Rate of Return (IRR), allow to give a more encompassing vision on the profitability by considering the CAPEX and the OPEX, but also the system lifetime and its yield among others.

3.2 GRID FINANCING

3.2.1 Grid actors

Many different stakeholders can be labelled as grid actors. These include: [1]

- Regulatory bodies, such as National Regulatory Agencies (NRAs)
- Distribution System Operators (DSOs)
- Transmission System Operators (TSOs)
- Electricity commercialisation companies
- Energy service companies (ESCOs)
- Energy communities
- Consumer associations
- Individual consumers/prosumers
- Aggregators
- etc.

3.2.2 Distribution (DSO) and transmission (TSO) system operators

3.2.2.1 Liberalisation and unbundling principles

TSOs and DSOs are key in the electricity system as they allow to build a physical link between the electricity production points and the electricity consumptions points. The electricity sector in Europe used to be constituted by vertically integrated monopolies (state or privately owned) positioned on all activities (production, transmission, distribution, and supply) of the electricity system [1], [2].

However, in the last decades the European electricity market has undergone major changes, in particular electricity markets were gradually open to competition and a unified European energy market was established. In addition, in many European countries, historical vertically integrated monopolies' activities were split with generation and supply becoming competitive activities while transmission and distribution activities remained non-competitive but subject to regulatory control. These changes were made in the frame of multiple directives which aimed at providing a clear European Union electricity market legislation, in particular the unbundling requirements which made the aforementioned split mandatory for Member States [1], [3]–[6]. The unbundling regimes can be found under the form of full unbundling (FU) model (further divided into two options: ownership unbundling (OU) or an independent system operator (ISO)) or an independent transmission operator (ITO) [7].

3.2.3 DSO and TSO landscape in Europe

3.2.3.1 TSO

Electricity transmission is a natural monopoly which is handled by Transmission System Operators (TSOs). TSOs are fully regulated companies and unbundled companies. According to the European Network of Transmission System Operators for Electricity (ENTSO-E) there are 43 electricity transmission system operators (TSOs) in 36 countries across Europe. The number of TSOs, the chosen unbundling model (ITO/ FU(OU) / FU(ISO) or hybrid) and the chosen ownership structure (state ownership / private ownership / hybrid) varies across the countries. Notwithstanding these differences, a unique TSO with a FU(OU) unbundling model with a split ownership between public and private seems to be the most frequent configuration [1] [7] [8].

Table 3-1 - TSO's name, unbundling model and ownership structure in studied countries [7] [8]

Country	TSO	Unbundling model	Ownership structure
Austria	APG	ITO + OU	75% public - 25% private
Belgium	ELIA	OU	47% public - 53% private
Denmark	ENERGINET	OU	100% public - 0% private
France	RTE	ITO	85% public - 15% private
Germany	TRANSNETBW TENNET AMPRION 50HERTZ TRANSMISSION	ITO + OU	TSO dependent
Italy	TERNA	OU	30% public - 70% private
Netherlands	TENNET TSO B.V.	OU	100% public - 0% private
Poland	PSE OPERATOR	OU	100% public - 0% private
Spain	REE	OU	20% public - 80% private

3.2.3.2 DSO

Electricity distribution is a natural monopoly which is handled by Distribution System Operators (DSOs). DSOs are fully regulated companies and unbundled companies. The number, concentration and ownership structure vary a lot from country to country with no recurring configuration [9] [10].

Table 3-2 - DSO number, concentration and ownership structure in studied countries [10]

Country	Total DSOs	Concentration	Ownership structure
Austria	126	Low: Mainly small, local DSOs. The three largest DSOs usually deliver less than 50% of distributed power. The largest delivers approximately 15% of consumption.	Largely public - National
Belgium	16	Low: Mainly small, local DSOs. The three largest DSOs usually deliver less than 50% of distributed power. The largest contributes about 10% of distributed electricity.	Largely public - Municipalities
Denmark	40	Low: Mainly small, local DSOs. The three largest DSOs usually deliver less than 50% of distributed power. The largest group delivers energy to a third of customers	Largely private - Customers

France	144	High: One dominant DSO (more than 80% of distributed power) and several local DSOs. The largest equates to 95% of consumption.	Largely public - National
Germany	883	Low: Mainly small, local DSOs. The three largest DSOs usually deliver less than 50% of distributed power. The largest represents approximately 25% of consumption.	Largely public - Municipalities
Italy	128	High: One dominant DSO (more than 80% of distributed power) and several local DSOs. The largest operator accounts for 85% of consumption.	Largely private
Netherlands	6	Medium: A mix of DSOs, with the three largest accounting for more than 60% of distributed power. Six DSOs have more than 100 000 customers	100% public - Municipalities
Poland	184	Medium: A mix of DSOs, with the three largest accounting for more than 60% of distributed power. Five DSOs have more than 100 000 customers	Largely public - National
Spain	354	Medium: A mix of DSOs, with the three largest accounting for more than 60% of distributed power. The largest delivers approximately 40% of total consumption.	Largely private

3.2.4 TSO and DSO activity scope

3.2.4.1 TSO

According to the Directive (EU) 2019/944, a TSO is *"a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity"* [3].

3.2.4.2 DSO

DSOs have three main functions:

- System operators: They ensure a reliable electricity flow through their network to their customers. They develop and maintain this network to ensure efficient, secure, reliable and quality operations [11].
- Information providers [10].
- Market facilitators: They provide non-discriminatory and facilitated access to their network for other users (power generators, customers, service providers, …). They also collaborate with TSOs [2] [11].

In the framework of the Clean Energy Package, the recast of the Electricity Directive (2019/944/EC) has added additional functions to the scope of activities that may be handled by DSOs. These additional functions include securing smart grid operation (owning and managing metering infrastructure, organising supplier switching, storing and providing metering data, …) and system stability [10] [11].

It should be noted that DSOs are not allowed to own or manage recharging points and energy storage facilities with the main aim to sell and buy electricity. However, storage systems can be used to ensure the secure operation of the grid [2]. There are also some national deviations to this rule (e.g., in Hungary, DSO are allowed to own BESS provided that it has a power below 0.5 MW). [12]

3.2.5 Network tariff regulation method

Network tariffs are the prices that network users pay for having electricity transported from the production site to the location where it is used. The core objective of tariffs is the recovery of the costs associated with the above listed functions and activities. These tariffs, which are applied during a regulation period, should both ensure affordability of electricity for end-users as well as financial stability for DSOs and TSOs [12, 13]. In order to achieve this goal, several network tariff regulation methods have emerged based on cost, investment, capital and the cost of capital. These differ in several ways and plentiful variations and hybrid combinations exist across countries. However, they may be summarised into four main input-based categories. In most countries, TSOs and DSOs apply the same tariff regulation methods (with some variations), but this is not an obligation [14, 13, 15]. Eventually, the network tariff regulation method and final tariffs require approval from regulators.

Table 3-3 - General classification and description of input-based tariff regulation methods [15] [14] [16]

	Input-based tariff regulation methods			
	Cost plus	**Rate of return**	**Revenue cap**	**Price cap**
Description	Prices: tariffs are set to allow costs recovery plus a legitimate profit.	Prices: tariffs are set to allow a legitimate rate of return on capital. Determined for the whole regulatory period	Prices: tariffs are set to reach (without exceeding) a certain revenue cap.	Prices: tariffs are set to reach (without exceeding) a certain cap.
	Considered costs: actual costs	Considered costs: historical costs	Considered costs: projected costs	Considered costs: projected costs
	Deviations: unplanned costs (upwards or downwards) are born by prices and thus customers.	Deviations: surplus/deficit will be balanced at the end of the regulatory period	Deviations: if costs are lower/higher than expected, the entity (TSO or DSO) bears the associated gains/losses.	Deviations: if costs are lower/higher than expected, the entity bears the associated gains/losses.
	Profit: Regulated entity is motivated to only increase the component used for profit calculation (expenses, assets / equity)	Profit: determined by the amount of invested capital and the costs of capital	Profit: since revenue is capped, profit can be achieved if lower costs than projected are achieved.	Profit: since tariffs are capped, profit can be achieved if throughput and number of customer increase.
Typical regulatory period	Short (typ. 1 year)			Long (typ. 8 years)
Risk of not recovering costs	Low			High
Motivation to improve efficiency	Low			High

In the nine studied countries, the most recurring network tariff regulation method is based on revenue cap (see Figure 3-2 and Figure 3-3). In most countries the same method is used by the DSOs and TSO(s). In addition, in many countries, the main tariff regulation method used also includes incentive-based or output-based elements. For these latter, revenues are dependent on whether and to what extent pre-defined targets (in terms of quality or service, deadlines, or availability for example) have been achieved by the end of the regulatory period [13, 14, 16, 17].

As a consequence of incentives-based methods being the most frequently chosen method in the studied countries, most of these countries have currently settled for regulatory periods ranging from 4 to 6 years (Italy being an exception with a period of 2 times 4 years) (see Figure 3-1). This regulatory period length has proved to be a good compromise between too long periods, which could lead to excessive risk on network entities and users due to higher deviation risks, and too short periods, which do not allow to grasp the benefits of incentive-based methods nor allow the regulatory stability [13, 17].

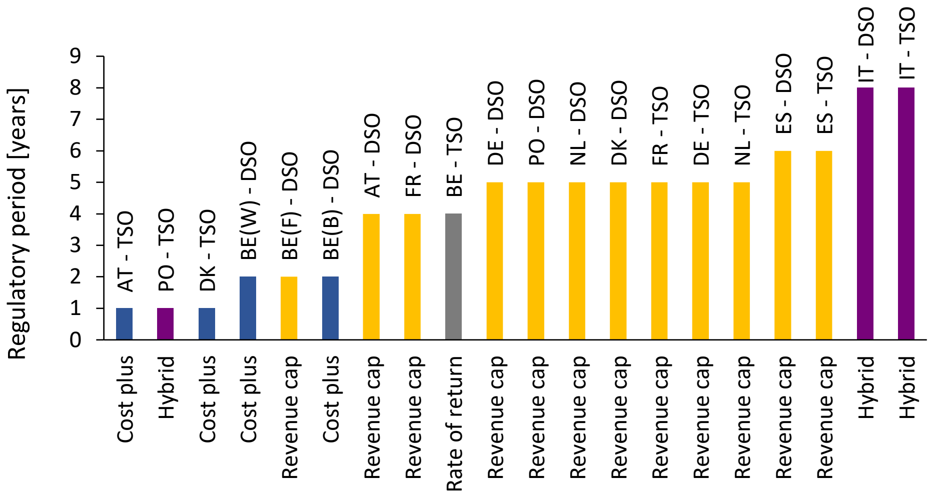


Figure 3-1- Correlation between chosen tariff regulation method and regulatory periods for DSOs and TSOs in studied countries in 2021

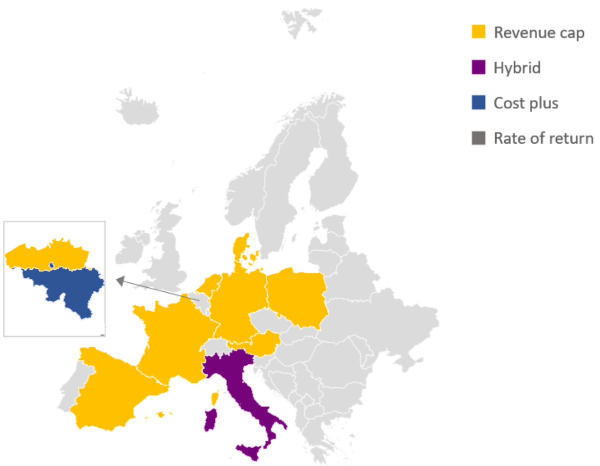


Figure 3-2- Tariff regulation methods used by DSOs in studied countries in 2021

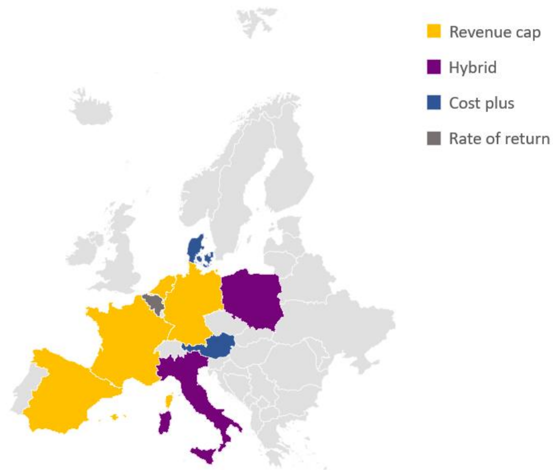


Figure 3-3- Tariff regulation methods used by TSOs in studied countries in 2021

3.2.6 Network tariff design

Network tariff design can be defined independently from the chosen grid tariff regulation method.

Tariffs not only aim at the recovery of the costs associated with TSO and DSO-related functions and activities while ensuring affordability of electricity for end-users as well as financial sustainability for DSOs and TSOs, but they also aim at sending price signals to network users in order to incentivise beneficial network behaviour [19].

Network tariffs design can build on three primary design options [19]:

- **capacity/power [€/kW]:** this component is either based on the network user's contracted capacity or on the network user's actual peak withdrawal over a certain time period (monthly or yearly)
- **energy/volumetric [€/kWh]:** this component is based on the network user's energy withdrawal from the grid
- **fixed [€/connection].**

These three primary design options are a direct reflection of the different nature of TSO and DSO costs which need to be recovered through tariff setting.

Indeed, DSO-associated costs include: [9, 19, 20]

- CAPEX: investment in assets necessary to provide network services such as:
  - overhead lines and underground cables (costs driver(s): **km, kVA and voltage level**)
  - substations (costs driver(s): **kVA, voltage level**)
  - control centres, information and communications technologies, metering systems (costs driver(s): **number of connection points/network users**)
- OPEX:
  - Operations, systems services and maintenance (costs driver(s): **km, kVA, voltage level**)
  - Procurement of network losses (costs driver(s): **kWh**)
  - Customer service: metering services, invoicing, and other administrative and commercial costs (costs driver(s): **number of connection points/network users**)

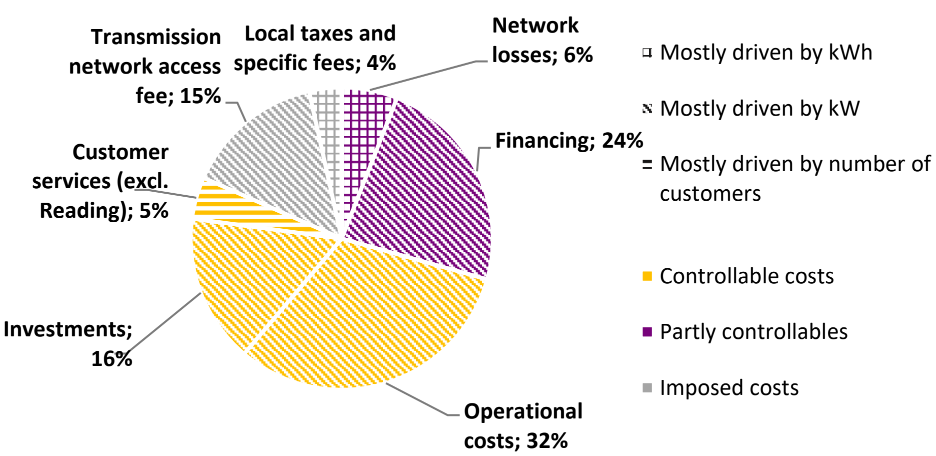


Figure 3-4 - Cost structure of a DSO as reported by [20]

While TSO-associated costs include [12, 20]:

- CAPEX of transmission investments (costs driver(s): **km, kVA and voltage level**)
- OPEX of transmission investments (costs driver(s): **km, kVA and voltage level**)
- Cost of losses (costs driver(s): **kWh**)
- Infrastructure-related compensations or other monetary transfers
- Cost of ancillary services and system balancing (energy)
- Cost of congestion management
- Non-TSO costs (stranded assets, various support schemes including those for renewables, for security of supply, …)

As shown in Figure 3-4, most of the cost components for DSOs are mostly dependent on/driven by power (kW). Similar conclusions can be made for TSOs. Nevertheless, the invoicing of the distribution and transmission grid tariff is currently largely based on energy. Indeed, although the network tariff design varies between the EU countries, majority are based on the variable energy amount (kWh) withdrawn from the grid. Exceptions for residential customers are the Netherlands which have a 100% capacity-based distribution and transmission tariff.

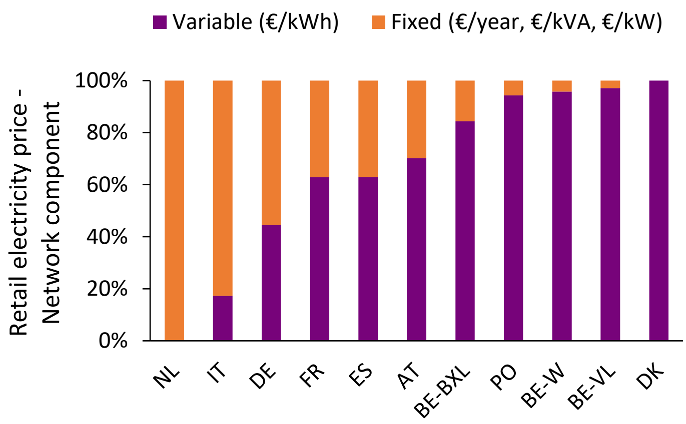


Figure 3-5 - Retail electricity price network component design for residential customers (3500 kWh/a) in studied countries in 2021

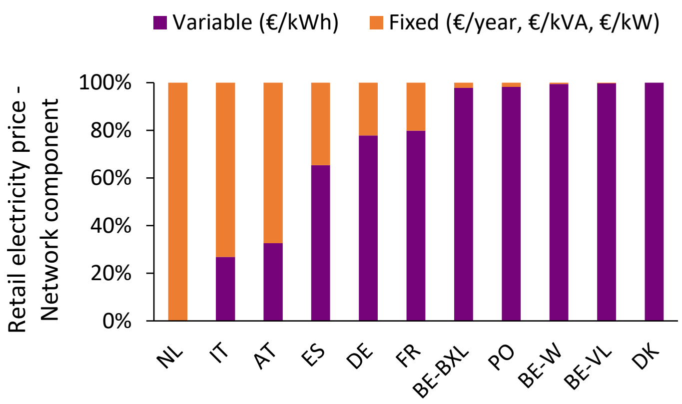


Figure 3-6 - Retail electricity price network component design for small commercial customers (30 000 kWh/a) in studied countries in 2021

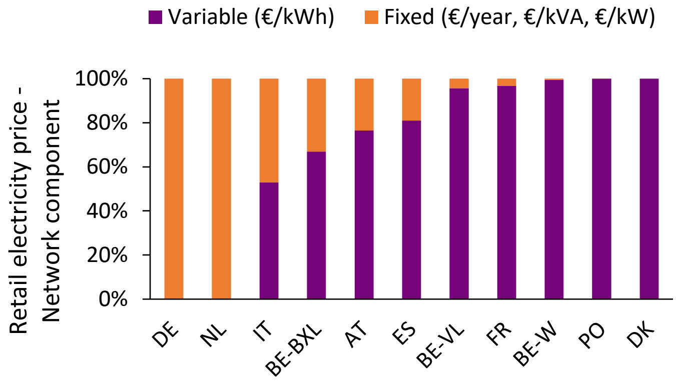


Figure 3-7 - Retail electricity price network component design for large industrial commercial customers (25 000 MWh/a) in studied countries in 2021

Table 3-4 - Sources and contributors per country for electricity retail prices structures

Country	Sources and contributors
Austria	https://www.e-control.at/
Belgium	(Wallonia) https://www.cwape.be/?dir=2.7.01 (Flanders) https://www.vreg.be/en (Brussels) https://www.brugel.brussels/
Denmark	https://energinet.dk/ https://nrgi.dk/
France	Information provided by CNR and My Light Systems
Germany	Information provided by Next Kraftwerke based on: Price sheet RNG (Rheinische Netzgesellschaft 2021)
Italy	https://www.arera.it/
Netherlands	Information provided by Next Kraftwerke based on: https://www.enexis.nl/ https://www.liander.nl/
Poland	Information provided by Next Kraftwerke based on: https://dobryprad.pl/dystrybucyjne/przesylowa/ https://www.rachuneo.pl https://www.innogy.pl https://www.enea.pl https://www.tauron-dystrybucja.pl https://www.energa.pl
Spain	Information provided by Grupo Cobra and Tecnalia

In addition to the three primary design options presented above, additional elements can be considered in the tariff design. These additional grid tariffs design options are both compatible with each other as well as with fixed, capacity-based, energy-based or hybrid tariffs and can be classified into two main categories.

First, network tariffs can be **location-differentiated**. While network costs are highly dependent on the local conditions (user density, characteristics of local network assets such as the presence of overhead or underground lines, geographical/topological constraints, local electricity supply and demand imbalances…), network tariffs are often constant across a country or a region [19].

Then, network tariffs can be **time-differentiated** (time-of-use (ToU) tariffs). These tariffs can take the form of static tariffs, in which case they are set differently for specific and well-ahead predefined time intervals. Typically, two different tariffs are set for on one hand on-peak time intervals and off-peak time intervals [19, 18]. Dynamic time-differentiated tariffs are also possible thanks to improvements in terms of measuring and availability of close to real-time information on consumption and production. The main principle remains the same compared to static time-differentiated tariffs, but tariffs are typically set at shorter notice, possibly close to real-time and for a reduced cumulative number of hours per years. Higher prices periods can for example reflect times when electricity demand is challenging to be met (critical peak pricing (CPP)). While dynamic tariffs allow can be considered more efficient by offering better reactivity to short-term network conditions changes, they also introduce more complexity for grid operators and end-users [18, 19].

4 GRID FINANCING AND PV PROFITABILITY REFERENCE CASES & INDICATORS

4.1 REFERENCE CASES

4.1.1 DSO & TSO customer basis segmentation

In order to study the impact of higher PV penetration on grid financing, DSO & TSO customer basis segmentation is defined. This customer basis and its segmentation are based on the following criteria:

- Customer basis is greater than 100 000 so that unbundling principles apply
- Segments are precise enough to encompass customers with sufficiently homogeneous characteristics
- Segments are large enough to avoid useless complexity and to be able to provide clear and interpretable results.

We defined five electricity consumer meta-categories which compose the DSO & TSO customer basis:

- Residential
- Small commercial
- Large commercial
- Small industrial
- Large industrial

The different segments are then associated to a given proportion in the total customer basis (See Figure 4-1).

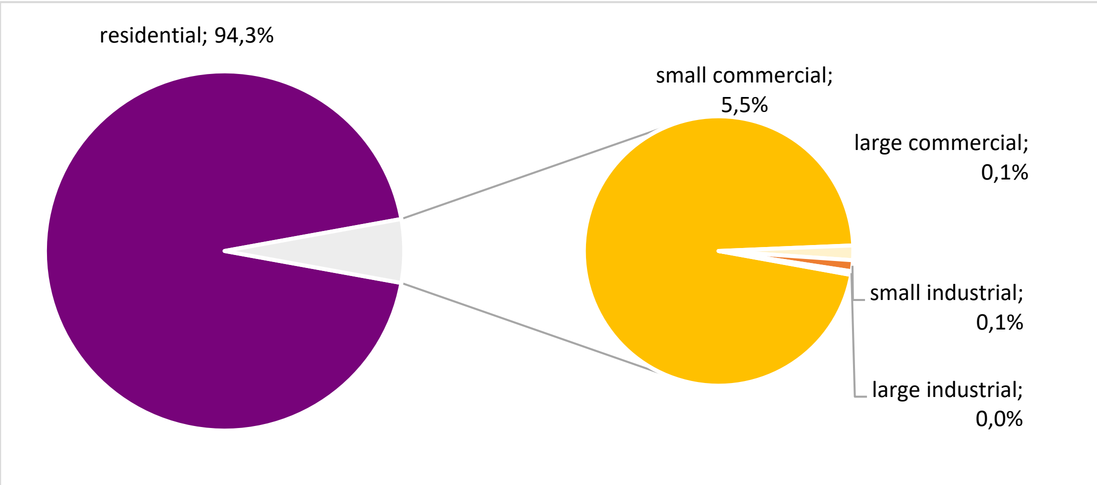


Figure 4-1 - Considered simplified customer segmentation for DSO & TSO reference cases (indicated percentages correspond to the share in total number of connection points and not in total consumed kWh)

Notes: the presented shares are based on real shares observed in Spain (as reported by Tecnalia), in Wallonia (as reported by the CWaPe) and in Brussels (as reported by Sibelga). Deviations from these values may be observed in some countries or regions.

4.1.2 Electricity consumers

The different segments are also described based on typical quantified characteristics to create reference cases. As mentioned, the segments were chosen to encompass customers with sufficiently homogeneous characteristics. However, the residential segment for example incorporates consumers which can have an annual electricity consumption varying from just around 1 MWh/year to a few dozens of MWh/year. Thus, the considered average annual electricity consumption in the residential reference case cannot aim at being representative of all customers but still is consistent with the weighted average annual electricity consumption (the weights being the share of residential households with a given annual consumption in total residential households).

In addition to the five reference cases, additional variations are considered. These include the ownership of PV systems or of flexibilities (electric vehicles, electric vehicle fleets, heat pump).

The five reference cases and their variations are described in the tables below according to their average annual electricity consumption, their subscribed power, as well as their self-consumption and self-sufficiency rate in the case of PV system ownership.

Table 4-1 - Considered residential consumer characteristics

Rooftop PV				
Electric vehicle	x		x	
Heat pump	x	x		
Annual electricity consumption	3.5 [MWh]	8.9 [MWh]	7.2 [MWh]	11.8 [MWh]
Subscribed power	5 [kVA]	6 [kVA]	5 [kVA]	9 [kVA]

Table 4-2 - Considered commercial and industrial consumer characteristics

	small commercial		large commercial	small industrial	large industrial
Electric vehicle	x		x	x	x
Annual electricity consumption	30 [MWh]	54 [MWh]	200 [MWh]	2500 [MWh]	25000 [MWh]
Subscribed power	30 [kVA]	35.1 [kVA]	200 [kVA]	2500 [kVA]	25000 [kVA]

Table 4-3 - Considered residential prosumer characteristics

Rooftop PV				
Electric vehicle	x		x	
Heat pump	x	x		
Installed capacity	5 [kWp]	5 [kWp]	5 [kWp]	5 [kWp]
Self-consumption rate	25 %	52 %	50 %	77 %
Self-sufficiency rate	32 %	33 %	38 %	33 %

Table 4-4 - Considered commercial and industrial prosumer characteristics

	small commercial		large commercial	small industrial	large industrial
Electric vehicle	x				
Installed capacity	50 [kWp]	50 [kWp]	250 [kWp]	1000 [kWp]	1000 [kWp]
Self-consumption rate	40 %	80 %	55 %	90 %	100 %
Self-sufficiency rate	70 %	49 %	70 %	40 %	5 %

4.1.3 PV producers

Finally, we define a last category of pure producers.

Table 4-5 - Considered producer characteristics

	Ground-mounted PV
Installed capacity	50 [MWp]
Self-consumption rate	0%

4.2 INDICATORS

In order to assess the impact on grid financing, the revenues from network tariffs collection are used as indicator.

In order to assess the PV profitability common indicators will be used. These include the net present value (NPV) and the internal return rate (IRR) which are described below.

All positive and negative cash flows are simulated, on a yearly basis, they are then summarized in a profit and loss statement, which allows to subsequently quantify the yearly "free cash flows" via the cash flow statement. Based on the free cash flows, the **Net Present Value** of the project, expressed in $€_{\text{base year}}$ is calculated, by discounting all these free cash flows back to the initial year of investment [22].

The **Internal Rate of Return** is a discount rate that makes the net present value (NPV) of all cash flows equal to zero in a discounted cash flow analysis. The Modified Internal Rate of Return (MIRR) is a slight variation of the internal rate of return, in which the financing rate and the reinvestment rate are differentiated, which better reflects reality. Note also that the MIRR can be computed in various ways. Firstly, it can be calculated for the PV asset as such, not considering the financing conditions, leading to the project MIRR. For that reason, this indicator can also be referred as the unlevered IRR. Secondly, the so-called equity MIRR, or levered MIRR, can be computed, i.e. the MIRR for equity investors of the project, taking into account the financing conditions of the project. Both are often computed as they provide valuable information and can have an interest for different stakeholders [22].

5 IDENTIFYING AND DEFINING THE IMPACTS OF HIGHER PV PENETRATION ON GRID FINANCING AND PV PROFITABILITY

5.1 Impacts on grid financing

In this section, we focus on the impact of higher PV penetration rates on revenues for grid operators. Additional costs related to higher PV penetration rates such as higher administrative costs or investment costs for grid upgrade will be briefly discussed qualitatively but will not be part of the quantitative analysis conducted within this deliverable.

5.1.1 Self-consumed distributed PV generation

Higher PV penetration rates across electricity consumers, increase the number of electricity consumers which can do self-consumption thus increasing their sufficiency and reducing the net amount of electricity they would withdraw from the grid. Under volumetric grid tariffs which are currently the most used grid tariff design in the studied countries, this reduction in volume taken from the grid could impact the revenues associated with grid tariffs collection [20]. The extent to which increasing PV penetration rates and more specifically, distributed PV penetration rates can jeopardize grid financing will be studied under different PV penetration rates among electricity consumers, under different adaptation/resilience scenarios at different time horizons and considering energy-based, capacity-based and hybrid (i.e., 50%/50%) network tariffs. First, the theoretical impact on revenues will be analysed. Then, the extent to which different implemented network tariff regulation methods can nullify, mitigate or enhance these impacts will be discussed.

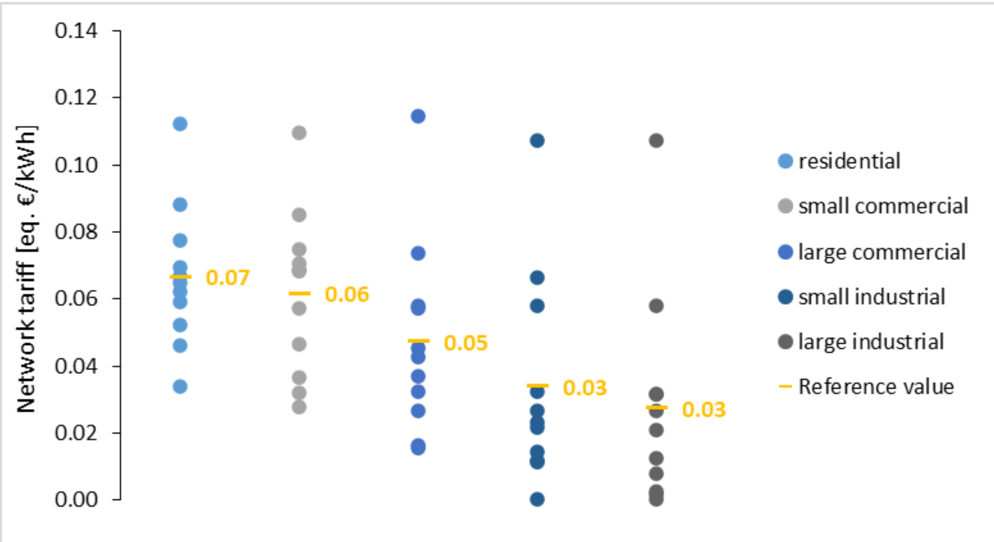


Figure 5-1 – Range of network tariffs in the nine studied countries and regions for the five reference cases in 2021 (See Table 3-4)

Table 5-1 - Considered base case network tariffs for three studied grid tariff designs

Customer category	Energy-based	Hybrid	Capacity-based
	[€/kWh]	*[€/kWh ; €/kW]*	*[€/kW]*
residential	0.07	0.033 ; 26.9	53.7
small commercial	0.06	0.031 ; 29	57.9
large commercial	0.05	0.024 ; 43.7	87.4
small industrial	0.03	0.017 ; 81.3	162.5
large industrial	0.03	0.014 ; 68.1	136.1

These base case tariffs are defined [1] reflecting current average tariffs levels (energy-based and capacity-based) in studied countries (See Figure 5-1) [2] to yield equal total revenues in the 2022 base case regardless of the considered grid tariff design.

5.1.2 Administrative costs for distributed PV

Historically, flexibility resources were provided by conventional generation plants connected to the transmission network. To guarantee the security and resilience of the transmission and distribution systems, and with the increase of penetration of renewables in the distribution network, there is an increasing need for flexibility at the distribution level. The observability of the distributed generation plants behaviour and the distribution system is required of a better integration of renewables. Therefore, DSOs need to be allowed to use the flexibility technologies connected to their systems to fulfil their responsibilities, including involvement in operational planning and procurement of congestion management and voltage control services, thus requiring a better DSO/TSO coordination. Improved forecasting, higher control logics, optimization, reliable communication are needed at distribution level to enable a higher flexibility in the markets. Including such tasks in the scope of DSOs operational activities will result in a higher administrative workload. [23], [24]

5.2 Impacts on PV profitability

5.2.1 Risks and uncertainty sources independent from PV penetration

Various risks and uncertainties may impact PV profitability, especially for centralized PV applications. Those which are not impacted by higher PV penetration rates are listed and briefly presented below in Table 5-2. They are not part of the scope of this report. This study focusses on risks for PV profitability arising due to a higher PV penetration. Though the risks listed in Table 5-2 are not analysed individually, their impact is still considered through a unique state of the art discount rate which reflects the risks associated with the investment in a PV project. A detailed model of these risks and their impact on PV profitability will be addressed in another SERENDI-PV report (task 2.5).

Table 5-2 - Risk and uncertainties for centralized PV project development

Risk & Uncertainty	Description	Impacted KPI
Solar resource	On the short-term, deviations might be observed between modelled resource and real resource. These deviations depend on the accuracy of initial estimates and on the year-by-year variability. On the long-term there is also uncertainty related to the long-term trends concerning the evolution of global available solar resource.	Generated electricity
Under-/Over-performance	The PV system (all components including PV modules but also inverters, and other balance of system elements) performances are higher or lower compared to initial simulation results.	Generated electricity
Environment: Albedo, Soiling, Shadowing, Snow, Temperature	Deviations might be observed between expected environmental conditions and real conditions.	Generated electricity
Site accessibility and suitability	Site accessibility and suitability are not as projected or as indicated by soil studies.	CAPEX & OPEX
Freight & Delivery	Freight costs and/or delivery times are not as projected.	CAPEX & OPEX
Taxes & duties	New taxes and duties are introduced related to the procurement or the installation phase.	CAPEX
Currency	Currency conversion rates fluctuate based on (geo)political, economic, financial context.	CAPEX
Weather event, animal degradation, vandalism and theft	Weather event and/or animal degradation and/or vandalism and/or theft occur leading to the (partial) destruction of the PV system, the (partial) interruption of electricity production until repairs and replacements are done. Damages are not sufficiently important or not applicable for insurance.	OPEX & Generated electricity
Repairs and replacements (modules, inverter and BoS) & Spare parts availability	Modules, inverters or BoS require repair or replacement leading to the (partial) interruption of electricity production until repairs and replacements are done. Repair and replacement are not covered by the guarantee or take place after the guarantee's expiration date. Poorly available spare parts might further increase delays until repair and replacement and costs.	OPEX & Generated electricity
Counterparty default	Retroactive measures are introduced changing the value at which electricity can be valued compared to initial agreement.	Valuation of generated electricity

5.2.2 Risks and uncertainty sources dependent from PV penetration

5.2.2.1 Electricity market prices

There are several reasons to expect higher PV penetration rates having an impact on electricity market prices. First, as far as daily prices variations are concerned, an increased penetration of PV could exacerbate the mismatch between production and demand at the hours of the day when PV generation is high, leading to important price gaps (between the hours of the day when PV production is typically high and demand typically low and the hours of the day when PV production is typically low or non-existent and demand is high) on a daily basis. However, the increased penetration of battery storage units could moderate this mismatch by shifting the PV production towards times of the day of higher demand. However, low midday prices could also stimulate an increased time-response demand.

In addition, concerning seasonal price variations, the combination of an increased electrification of the energy sector, in particular of highly season-related needs such as heating, as well as an increased PV penetration, the mismatch between production and demand in winter could be exacerbated, leading to important prices gap on a seasonal basis. However, the increasing degree of interconnection of the national or regional European grids combined with the increased penetration of hydrogen in seasonal storage applications, could allow to diminish this mismatch by improving the balancing between regions or shifting the PV production towards times of the year of higher demand.

Eventually, in terms of negative prices, the combination of an increased penetration of electricity generating units with low marginal costs of production (renewables) as well as the preservation of electricity generating units with higher marginal costs (coal and gas-based power plants and to a lesser extent nuclear power plants), could lead to an increase of negative prices periods. This trend can already be observed on European wholesale electricity markets, with a twofold increase of negative prices hours in summer and spring between 2016 and 2017 and a four to fivefold increase between 2016 and 2019 [25].

Higher PV penetration rates have the potential to impact electricity market prices to different extents depending on PV penetration pathways and the ability of the grid and society to adapt (electrification, demand-side flexibility, interconnection…). Changes in the electricity market prices can in turn impact PV profitability. Indeed, for subsidy-free solar PV, the business models often rely on selling the produced electricity on the wholesale spot day-ahead market. This is also the case for installations with signed Power Purchase Agreements (PPAs), where the whole production is not covered by the agreements and the remaining electricity will also be sold on the wholesale market. In the case of distributed PV, significant impact on wholesale electricity price may also impact revenues from excess electricity if bought by a utility and from self-consumed electricity as wholesale electricity prices influence the commodity component of retail electricity prices.

5.2.2.2 Imbalance prices

The imbalance price is the price which reflects the difference between the volumes sold in the wholesale electricity market based on forecasts and the actual injection. [3], [26] In general, a short position (i.e. more power was sold than what has been injected) is penalised at a price higher than the day-ahead market. At moments of shortage in the grid, these imbalance fees will be many times higher than the day-ahead market prices. A long position (i.e. when less power was sold than what has been injected), the extra volume receives a payment which is usually lower than the day-ahead market prices. At moments of large excesses in the grid, these prices might become zero or negative.

With higher PV penetration rates, it can be expected that imbalance prices will be impacted. Indeed, with a higher share of the electricity being produced by PV, short positions and long positions will typically take place at the same time for all centralised PV systems, even if to various extents, thus exacerbating imbalances and increasing imbalance prices. However, the improvement of electricity demand forecast accuracy, PV production monitoring quality and PV production forecast accuracy could nullify the impact of higher PV penetration rates on imbalance prices. The latter in particular which is one of the key topics addressed in SERENDI-PV could hedge the risk associated with imbalances. As this topic is specifically tackled in other SERENDI-PV work packages (WP5), it will not be studied as a separate risk in the present deliverable.

5.2.2.3 Grid failures and outage

This risk is capped in certain countries. In France for example, a compensation is foreseen by ENEDIS for grid failures and outages up to a certain number of hours.

This risk is not studied individually.

5.2.2.4 Development and End-of-Life regulations

The development regulation risks encompass the introduction of new regulations related to the project development phase (additional administrative procedures, restrictions, …) which can lead to delays and thus higher CAPEX. Measures leading to the simplification of the development phase are also possible in an attempt to accelerate PV deployment. The end-of-life regulation risk encompasses the introduction of new regulations related to the end-of life phase (additional administrative procedures, restrictions, financial provisions…) which can lead to additional costs. Finally, the environmental regulation risk covers the introduction of new regulation related to environmental impact which could lead to higher costs both for OPEX (mitigation measures) and CAPEX (constraints in terms of CO_2 content of some parts of the PV systems which can be more costly).

It is relatively certain that such regulatory evolutions related to development, environmental impact and end-of-life will be observed as the PV penetration increases. However due to the high level of uncertainty it is difficult to make sound assumptions on how (positively or negatively) and to what extent these risks could impact the profitability.

5.2.3 Other key influential factors for PV profitability

Additional factors may be introduced here. They are not directly impacted by higher PV penetration rates. However, they are worth considering as (1) - they can have a significant impact on PV profitability and (2) – they are indirectly impacted by higher PV penetration rates, or more precisely they are bound to evolve and change in parallel with the increase of PV penetration. Therefore, a sensitivity analysis will be conducted for these factors.

These are:

- PV subsidies or business models in general
- Network tariff design
- Self-consumption rates
- PV system orientation
- Irradiation conditions.

It should be added that financial parameters (inflation rate, interest rate, share of debt, …) affect the discount rate which is an important input used for profitability metrics such as Net Present Value (NPV) and Levelized Cost of Electricity (LCOE). There is not sensitivity analysis conducted on these parameters specifically as part of this report.

6 SCENARIOS

6.1 Qualitative description

6.1.1 PV penetration scenarios

The LUT Energy System Transition model can be utilized to generate wide-ranging energy scenarios across the different regions of the world on a global-local scale. However, the objective of this study is to highlight energy scenarios in context to achieving the goals of the Paris Agreement of achieving net zero GHG emissions from the energy sector, in a technically feasible and economically viable manner as it is reflected in the European Green Deal. Therefore, three distinct scenarios are envisioned for an integrated energy sector combining the power, heat, and transport demands for the case of Europe, from the current system in 2020 towards cost optimal energy systems with varying features by 2050 [27].

- **Business as usual**
- **Zero GHG emissions 2050**
- **Zero GHG emissions 2040**

Business as usual (BaU): In this scenario, the European energy system is set on a minimum ambition pathway, wherein the current and upcoming fossil fuels and nuclear power plants are not phased out and continue operating until end of their technical lifetime. In the transport sector, a slower rate of electrification of road transport leads to a longer presence of internal combustion engines (ICE) in road transport by 2050. Fuels for marine and aviation transportation are still 50% fossil by 2050 due to a delayed transition. Substantial new nuclear power plants, but also new fossil plants are added to the system according to scenarios of EC. The EC's vision of climate neutrality by 2050 is not achieved, as GHG emissions reduction are at 90% below 1990 levels. Medium GHG cost development is considered with present values in 2020 to 150 €/tCO_2 by 2050. Finally, the ambitious goal of the Paris Agreement of limiting mean global temperature rise to below 1.5^{o}C is violated.

Zero GHG emissions 2050 (ZE 2050): In this scenario, the European energy system is set on a medium ambition pathway, wherein the current fossil fuel power plants are phased out by 2050 and no new nuclear power plants are considered, with existing and under construction plants operating until end of their technical lifetimes. New coal plants are not allowed due to climate regulation, whereas new gas-fired power plants are allowed, but with the obligation to switch to non-fossil fuels during the transition. The EC's vision of climate neutrality by 2050 is achieved, as GHG emissions are zero in 2050. Medium GHG cost development is considered with present values in 2020 to 150 €/tCO_2 by 2050. Finally, the less ambitious goal of the Paris Agreement of limiting mean global temperature rise to below 2^{o}C is more likely achievable than the more ambitious target of 1.5^{o}C.

Zero GHG emissions 2040 (ZE 2040): In this scenario, the European energy system is set on a high ambition pathway, wherein the current fossil fuels and nuclear power plants are phased out by 2040 and no new plants are considered. New gas-fired power plants are allowed, but with the obligation to switch to non-fossil fuels before 2040. The EC's vision of climate neutrality by 2050 is achieved well before by a decade, as GHG emissions are zero in 2040. High GHG cost development is considered with present values in 2020 to 200 €/tCO_2 by 2040. Finally, the ambitious goal of the Paris Agreement of limiting mean global temperature rise to below 1.5^{o}C is more likely to be achieved. Furthermore, as this scenario achieves zero GHG emissions and 100% renewables by 2040, it presents an opportunity for Europe to proceed with additional GHG emissions reduction and thereby becoming a negative CO_2 emissions continent. This is primarily driven by additional capacities to produce renewables based synthetic fuels for defossilisation of the transport sector by 2040. This leads to an opportunity to produce additional volumes of renewable electricity-based e-fuels from 2045 to 2050. As remaining combustion vehicles in the stock are continued to be phased out beyond 2040, European demand for liquid fuels declines. The continued production of e-fuels leads to significant volumes for the export of renewable electricity-based e-fuels that enable displacement of fossil fuels in other regions, which further reduces GHG emissions globally and places Europe in a leadership position. This effectively leads to negative CO_2 emissions in Europe since the carbon for the e-fuels is mainly extracted from air.

6.1.2 Grid adaptation (electrification) scenarios

In addition to considering different paces at which PV deployments are being made, we also consider two scenarios which qualify the adaptability of the grid mostly to this increasing PV penetration. Thus, we consider two scenarios:

- **Low grid adaptation**
- **High grid adaptation**

In the **low grid adaptation** scenario, it is assumed that increasing PV penetration, potential issues related to variability of PV generation are further exacerbated. This leads to PV production not being efficiently used. Solutions such as storage (under various forms), or incentivized electricity consumption during PV generation peaks are poorly implemented. Electrification of transport and heating is conducted in an uncorrelated/connected way with PV generation (i.e. no smart charging, vehicle-to-grid, smart use of heat pumps, …).

In the **high grid adaptation**, it is assumed that even in the scenarios with the most rapid PV penetration increases, the ability of the grid to assimilate and deal with additional PV is high (in the BaU scenario, PV penetration growth rate is more limited, thus it can also be considered that in this scenario, the grid remains adapted). PV generation is efficiently used thanks to the implementation of solutions such as storage (under various forms) or incentivized electricity consumption during PV generation peaks. Electrification of transport and heating is conducted in an integrated/connected way with PV generation (i.e. implementation of smart charging, vehicle-to-grid, smart use of heat pumps, …).

6.2 Quantitative description

6.2.1 PV penetration in the electricity generation for various scenarios

The three PV penetration scenarios can be first quantitatively described using the following indicator: share of cumulative PV electricity generation in total electricity generation (See Figure 6-1). Other indicators such as the share of cumulative PV installed capacity in total electricity generation capacity, the share of total final electricity consumption met by PV production or the share of households equipped with a PV system can also be used to characterize PV penetration. While the share of households equipped with a PV system is presented in the following subsection, the other indicators are not used in the frame of this deliverable.

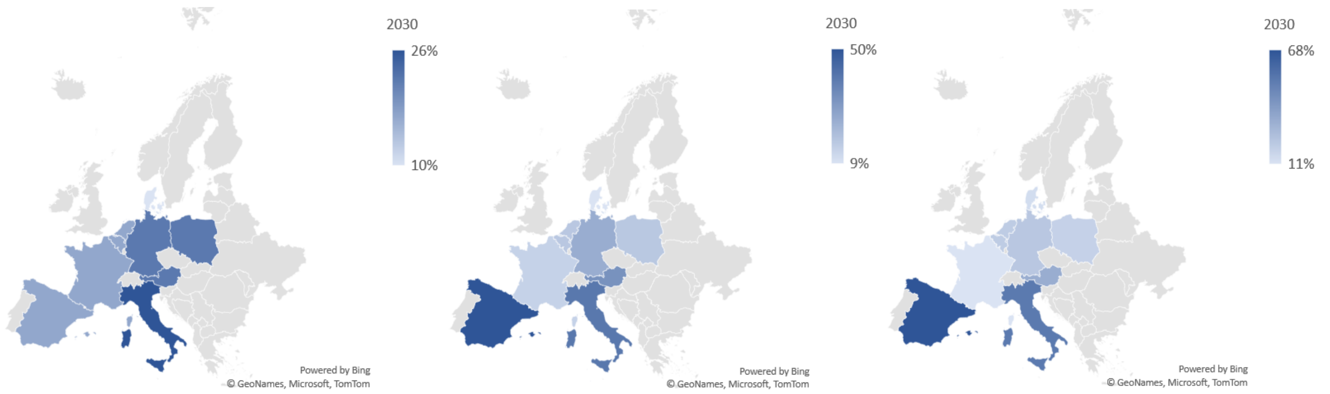


Figure 6-1 - PV penetration in electricity generation in studied countries under three PV penetration scenarios [23]

(left: BaU, middle: ZE 2050, right: ZE 2040)

6.2.2 Share of households equipped with a PV system

PV penetration is described in terms of share of households equipped with a PV system. For this purpose, only the distributed PV (i.e. rooftop) installed capacity is considered. As shown in Figure 6-2. the PV penetration (as defined by share of households equipped with a PV system) is the same in the ZE-2050 and ZE-2040 scenarios. Indeed, these scenarios differ only in terms of installed centralized PV capacity which does not impact the share of households equipped with a PV system. In addition, between the BaU and ZE_2050, the pace at which PV additions are made differs mostly for centralized PV, explaining why the BaU and ZE-2050 curves are relatively close

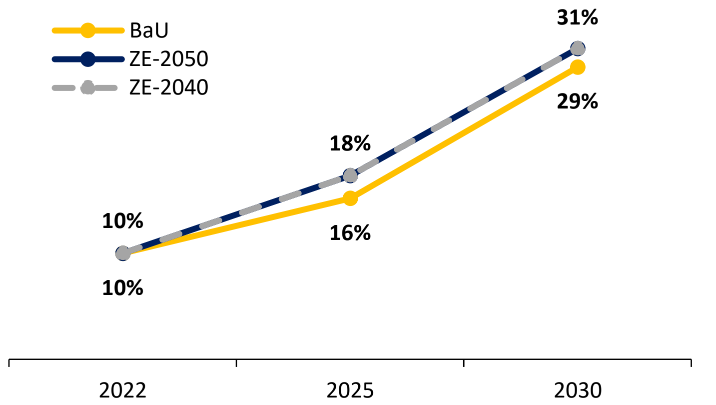


Figure 6-2 - Rooftop PV penetration in studied countries under three scenarios

Hypothesis: Average residential PV system size: 5kWp, share of residential distributed PV in total distributed PV: 50%, number of households in 9 studied countries assumed across the years: constant.

6.2.3 Cumulative PV installed capacity in the EU split by market segment

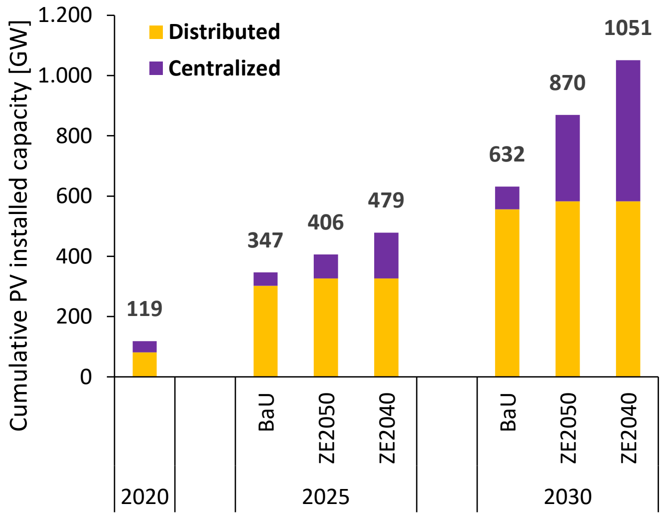


Figure 6-3 - Projected cumulative PV installed capacity split, for 2020, 2025 and 2030, by market segment and according to three different PV penetration scenarios (Elaboration by Becquerel Institute based on LUT's data)

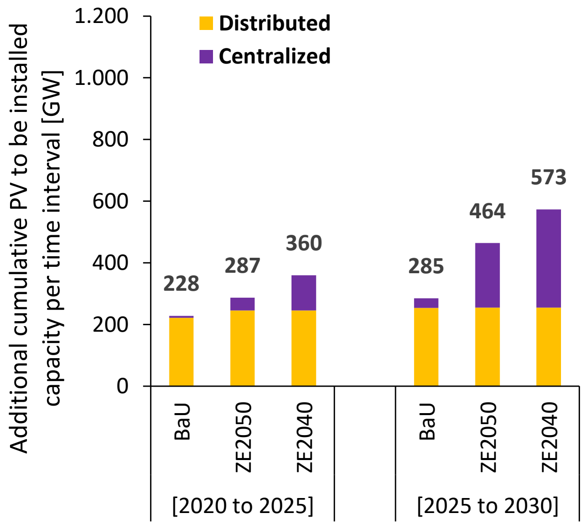


Figure 6-4 - Projected cumulative PV installed capacity split per period, by market segment and according to three different PV penetration scenarios (Elaboration by Becquerel Institute based on LUT's data)

6.2.4 Electricity wholesale market prices

6.2.4.1 General methodology

Electricity wholesale prices have been modelled, using Python and following a mean-reverting and jump-diffusion process (see formula below) which has been shown/presented in several studies/papers as one of the relevant functions to model commodities such as electricity prices [25, 26]. The inherent stochastic behaviour of the selected modelling process will be linked to (1) the probability of occurrence of prices shocks, (2) the amplitude of the price shocks and (3) the length of these price shocks (when applicable). To model electricity wholesale prices based on a mean-reverting and jump-diffusion process, a seasonal and daily component, the following equations were used:

$$\ln(P_t) = d(t) + s(t) + X_t$$

With:

P_t: the wholesale price of electricity

d(t): a daily pattern

s(t): a seasonal pattern

$$dX_t = (\alpha - \kappa X_t)dt + \alpha dW_t + J(\mu_J, \sigma_J)d\Pi(\lambda)$$

With:

α: first mean reversion parameter

κ: second mean reversion parameter

σ: volatility

W_t: standard Brownian motion

$J(\mu_J, \sigma_J)$: jump size with μ_J a normally distributed mean and σ_J a standard deviation

Π(λ): Poisson process with a jump intensity of λ.

Two additional features were added to the above presented model:

- the possibility for prices to go below 0 to model negative prices
- the merit order effect of PV.

6.2.4.2 Calibration determination of assumptions for future prices evolution

Historical wholesale market prices datasets have been used to calibrate and validate the model's accuracy compared to real prices (i.e., historical prices). Historical datasets before 2019 have been used to conduct the basis calibration for the modelling tool. Datasets subsequent to this date have been left out for the calibration process as they correspond to exceptional events (Covid lockdowns and geopolitical context with the war on Ukraine), having important impact on electricity prices. These datasets have nevertheless been of great value for other purposes. Electricity prices datasets dating from Spring 2020 (Covid 19-related lockdown) allowed to provide insights and order of magnitudes for contexts of higher PV penetration rates. Indeed, significant electricity demand decrease during the lockdowns at a time of the year when PV production is relatively high led to artificially high PV penetration rates. Electricity prices datasets dating from 2021 onwards (electricity demand surge due to economic activity recovery in all regions of the world as well as the current geopolitical context of war in Ukraine) allowed to provide insights and order of magnitude for contexts of turmoil and price hikes on electricity markets in general.

6.2.4.3 Key assumptions and parameters for the modelling

Depending on the considered scenario (PV penetration and adaptation), abovementioned parameters differ.

The key common points and differences across scenarios as well as results of electricity prices modelling are presented below.

- The **daily and seasonal pattern** are assumed being the same across all scenarios

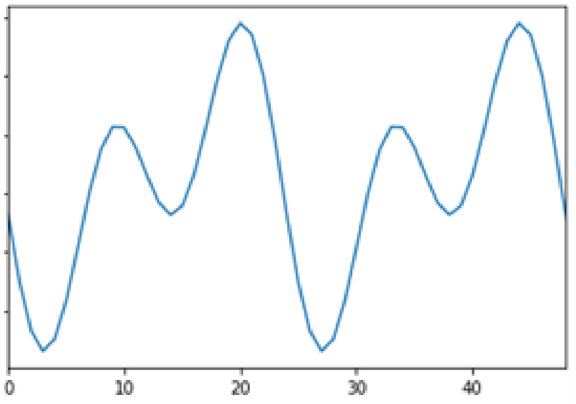


Figure 6-5 – Example of a daily pattern considered (48h display) based on the calibration conducted on historical prices datasets

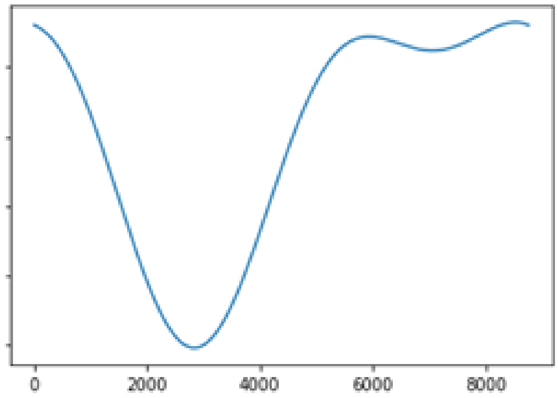


Figure 6-6 - Seasonal pattern (displayed for 1 year = 8760 hours) considered (based on calibration conducted on historical prices datasets)

The **parameters used for the mean-reverting jump diffusion process** are different depending on whether the low adaptation or the high adaptation scenarios is considered (See Table 6-1).

Table 6-1 - Parameters used for the mean-reverting and jump diffusion process in the two adaptation scenarios

	α	κ	σ	μj	σj	λ
Low grid adaptation	3470.07	9160.94	0.03	0.33	0.37	1549.18
High grid adaptation	3470.07	9160.94	0.03	0.33	0.37	1161.89

- The **merit order effect** is different depending on whether the BaU, the ZE_2050 or the ZE_2040 PV penetration scenario is considered. (See Figure 6-7)

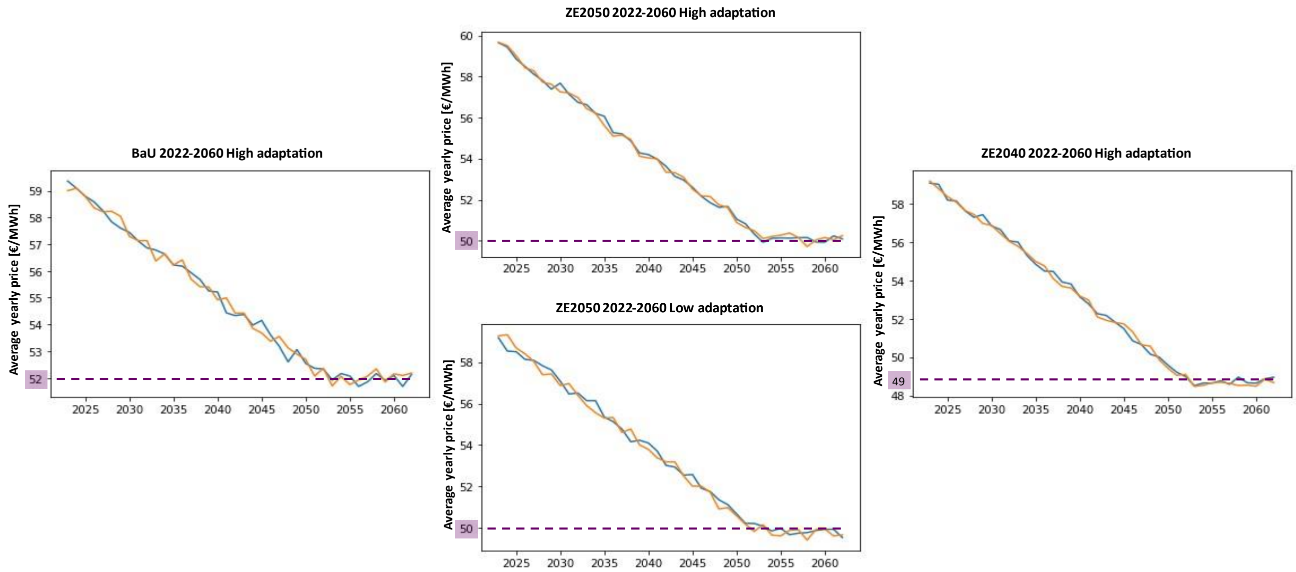


Figure 6-7 - Merit order effect for the three different PV penetration scenarios for 4 simulation runs

6.2.4.4 Results

Eventually the above presented methodology and parameters yield the following results. Simulated prices and historical prices yield a similar price distribution with most hourly prices being around 50 €/MWh.

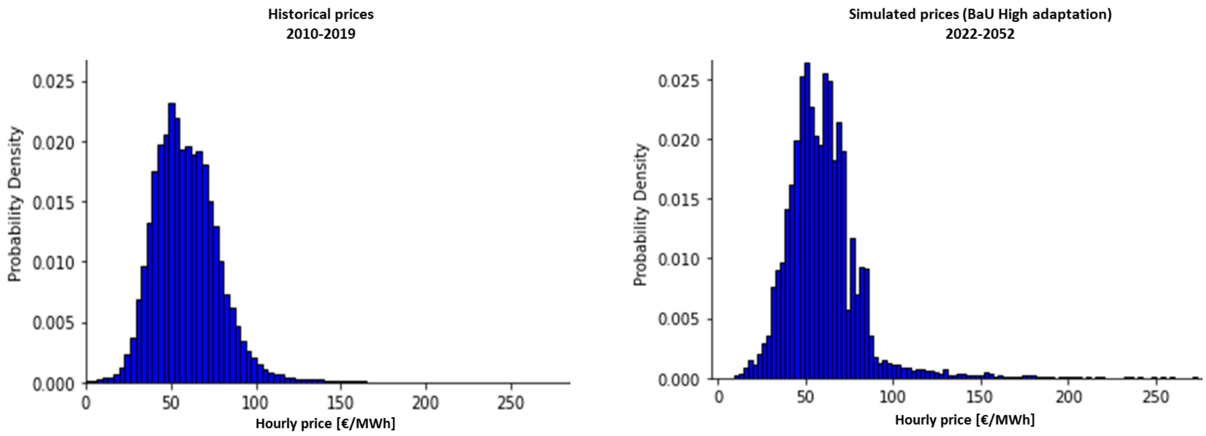


Figure 6-8 - Comparison of historical prices and simulated prices in terms of hourly prices distribution

Note: Historical prices are plotted after removal of negatives prices, simulated prices are plotted here before modelling the inclusion of negative prices

The highest 30% hourly prices (respectively the 30% lowest prices) typically take place in the morning and in the evening (respectively during the night and early in the afternoon) both for historical prices and simulated prices.

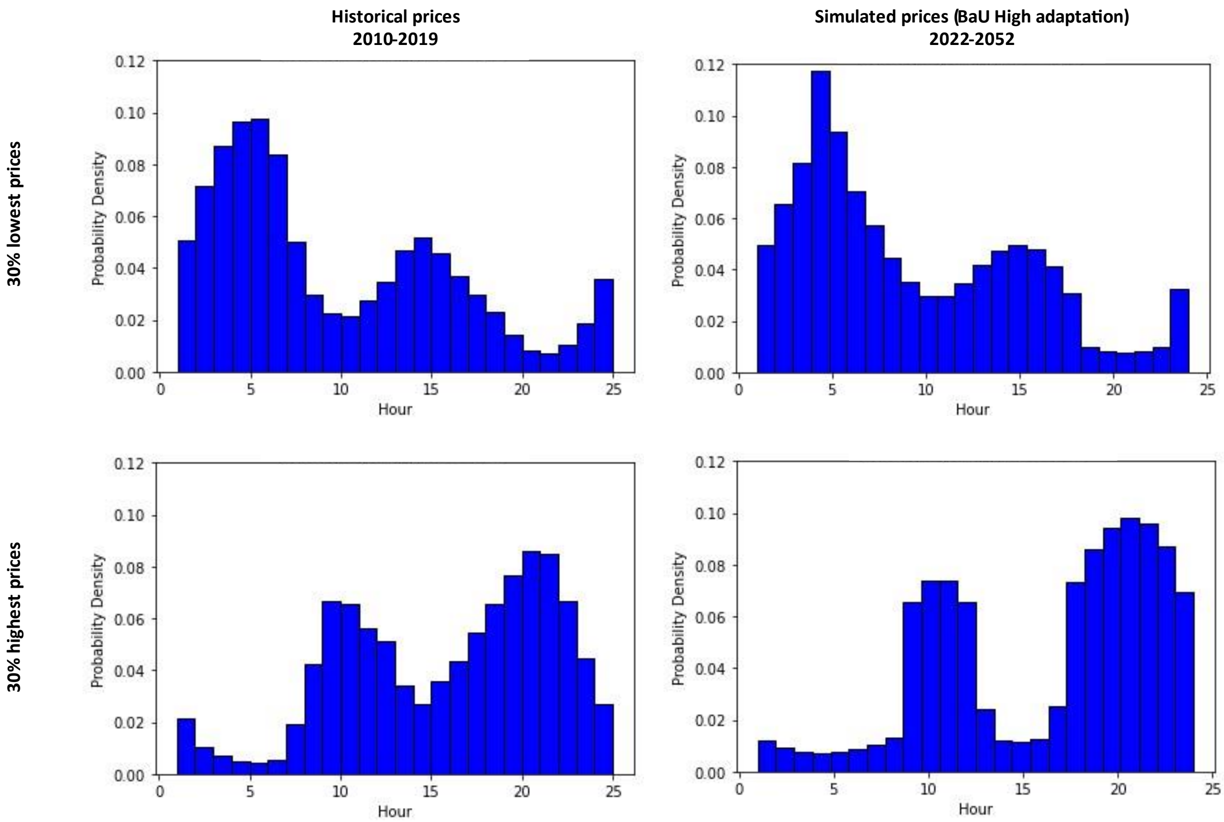


Figure 6-9 - Daily distribution of the 30% highest and lowest hourly prices for historical prices (left) and simulated prices (right)

The occurrence of negative prices varies depends on both the PV penetration scenario and the grid adaptation scenario (See Figure 6-10). Scenarios with higher PV penetration rates have a higher number of hours with negative hours. For low adaptation scenarios, the difference is even more notable with approximately a doubling of annual number of hours with negative prices. As a comparison, the number of hours with negative prices in some European countries in recent years can be found in Figure 6-10.

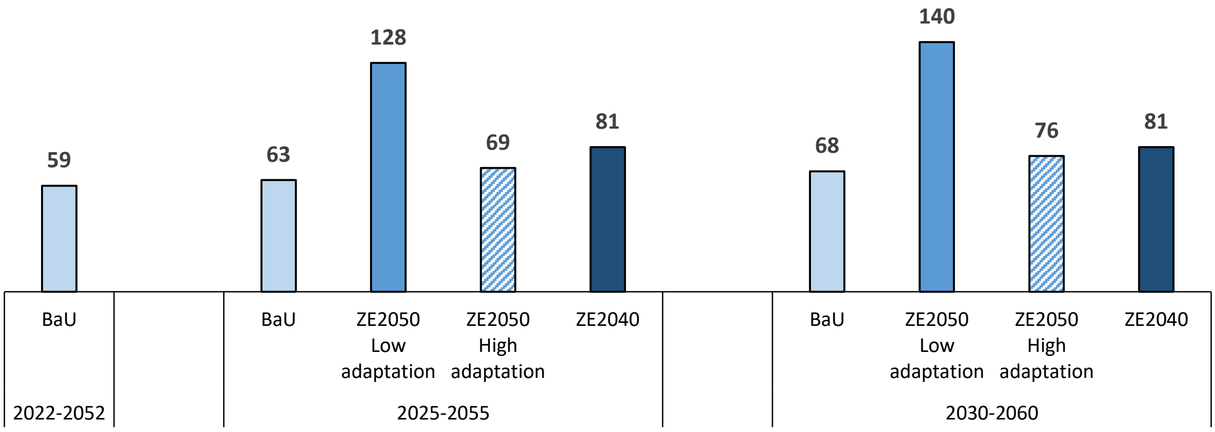


Figure 6-10 – Total number of hours with negative prices in the different PV penetration and grid adaptation scenarios over 30 years (i.e. PV system lifetime) at different time intervals

6.2.5 Electrification of the mobility and heating sectors

The impact assessment of higher PV penetration rates on grid financing is performed considering the changes in electrical needs based on two adaptation scenarios (low and high), based on the electrification of the mobility and heating sectors. It should be noted that electrification needs of mobility and heating were considered for residential consumers while only electrification of the mobility sector was considered for small commercial systems. No electrification needs of mobility and heating sectors were considered in the calculations for large commercial and small & large industrial systems. Indeed, for these segments, it is more difficult to estimate, for the customer segment as a whole, to what extent and for what aspects electrification can take place as it highly depends on the configuration and activity of the commercial or industrial customer. In addition, no assumptions related to energy efficiency improvements are considered. This is because, it is challenging to evaluate their impact for a customer segment as a whole and because it is hard to identify to what extent energy efficiency measures (in buildings mostly or in devices and equipment) will reduce electricity demand versus the demand for other energy vectors (gas, oil, …).

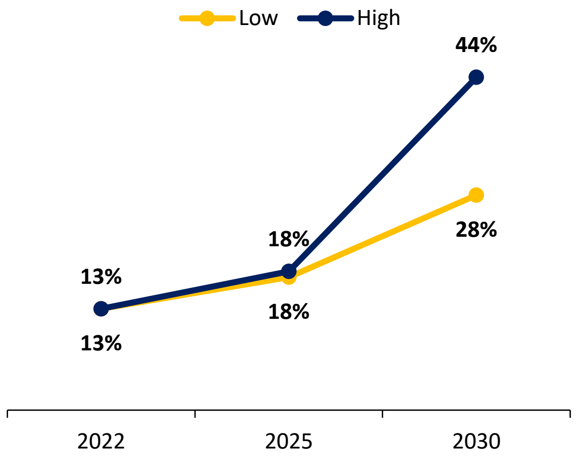


Figure 6-11 – Heat Pump (HP) penetration in studied countries under two grid adaptation scenarios (Elaboration by Becquerel Institute based on [27])

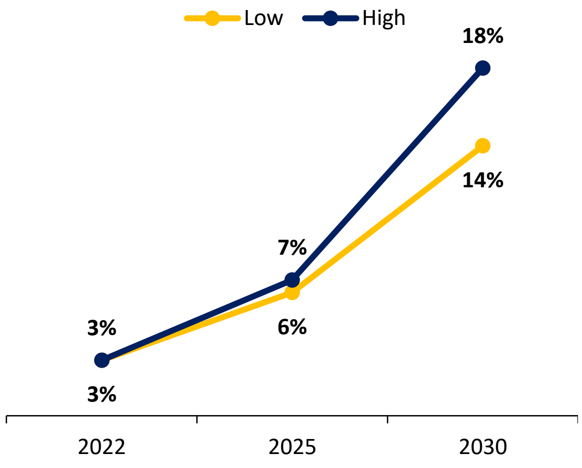


Figure 6-12 - Electrical Vehicle (EV) penetration in studied countries under two grid adaptation scenarios (Elaboration by Becquerel Institute based on [27]–[30])

7 QUANTIFYING THE IMPACTS OF HIGHER PV PENETRATION ON GRID FINANCING AND PV PROFITABILITY

7.1 Impacts on grid financing

7.1.1 Self-consumed distributed PV generation

7.1.1.1 Base case

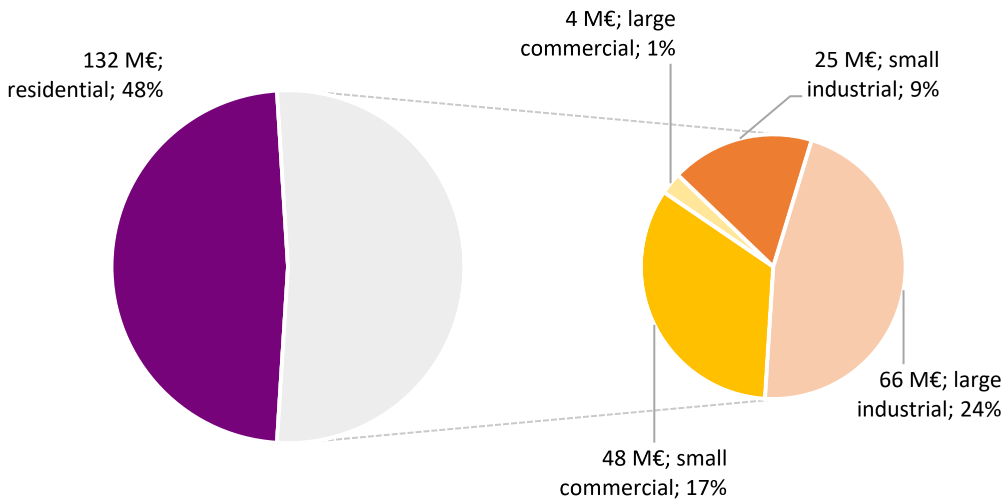


Figure 7-1 – Revenues in absolute and relative values from network tariff collection from five electricity consumer meta-categories

7.1.1.2 Quantified impact

Regardless of the considered time horizon (2025 and 2030), the PV penetration scenario (BaU or ZE_2050) or the electrification (or grid adaptation) scenario (low and high), and most importantly the network tariff design, the revenues associated to the collection of network tariffs from **residential customers** increase compared to the 2022 base case. This indicates that the revenue losses due to the decrease in net electricity consumption through wider presence of prosumers is largely compensated by the revenue gains linked to the increase in electricity consumption through the wider electrification of mobility and heating needs.

As far as revenues associated to the collection of network tariffs from **small commercial** customers is concerned, they stay relatively constant across the different PV penetration and grid adaptation scenarios and time horizons. Indeed, only electrification of mobility is concerned (no heat pump considered for this reference case), thus the impact of higher PV penetration rates slightly outweight the impact of electrification.

Revenues from **large commercials, small and large industrial**s decreases slightly over time in all scenarios. As no assuptions on electrification for these segments are made, the revenue losses are purely attributable to the increase in PV penetration rates. Yet, losses are limited to a few percents only on average (even less when considering industrial segments only). The reasons are mainly two. First, network tariffs for these consumers are lower and thus the shortfall are lower. Secondly the PV production can only cover a limited share of the important electricity consumption in this segment.

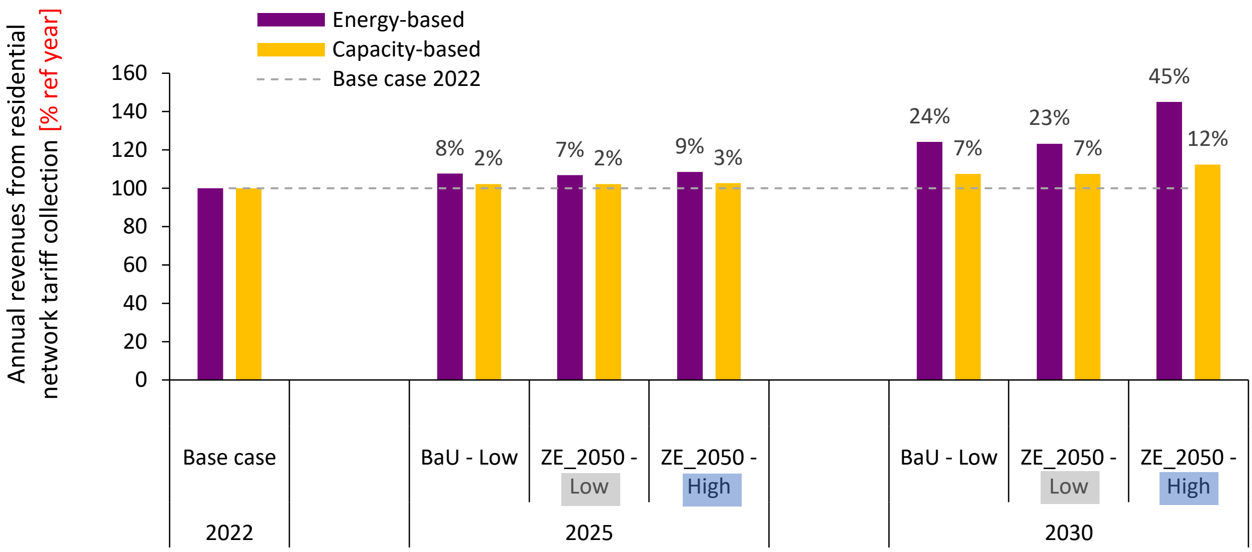


Figure 7-2 – Annual revenues from residential network tariff collection in the different scenarios and for two different network tariff designs

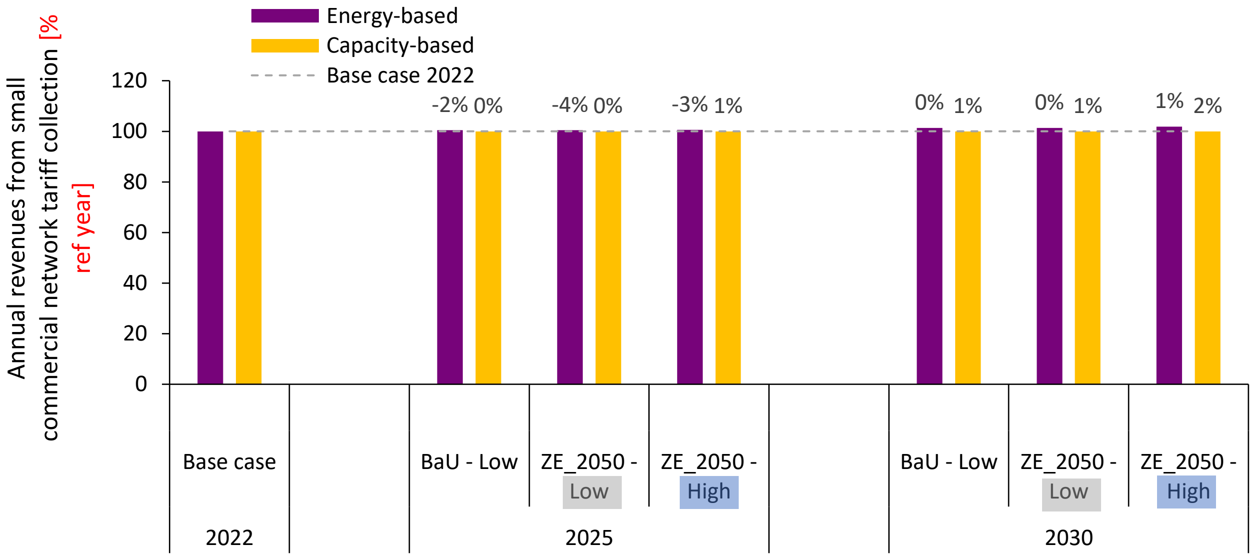


Figure 7-3 – Annual revenues from small commercial network tariff collection in the different scenarios and for two different network tariff designs

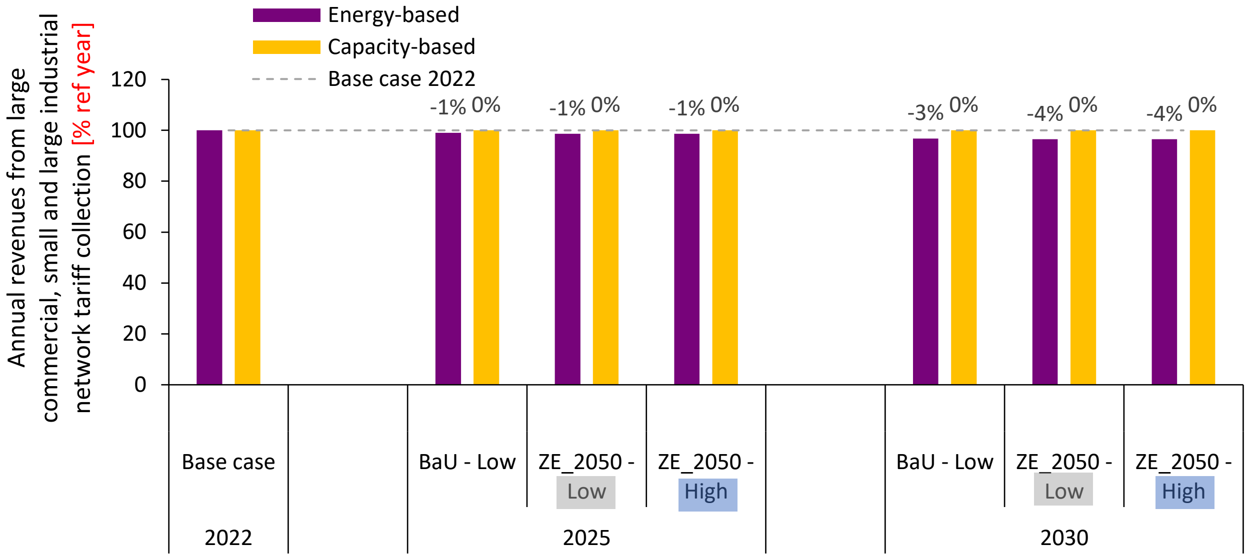


Figure 7-4 - Annual revenues from large commercial, small and large industrial network tariff collection in the different scenarios and for two different network tariff designs

Figure 7-5 looks in detail at the projections for 2025, the respective revenue impacts of higher PV penetration (continuous line arrow) and higher electrification / grid adaptation (dotted line arrow) under different network tariff designs for different types of customers can easily be identified. Under energy-based tariffs, revenues increase with higher electrification rates and decrease with higher PV penetration rates all other things being equal. Under capacity-based tariffs, higher PV penetration rates do not affect the revenues while higher electrification rates moderately impact the revenues (higher subscribed power is considered for owners of flexibilities such as EVs of heat pumps).

(millions)	Energy-based	Hybrid	Capacity-based
PV penetration: BaU Electrification: low	142.0	138.4	134.9
PV penetration: ZE-2050 Electrification: low	140.9	137.9	134.9
PV penetration: ZE-2050 Electrification: high	143.2	139.3	135.4

(millions)	Energy-based	Hybrid	Capacity-based
PV penetration: BaU Electrification: low	47.0	47.6	48.1
PV penetration: ZE-2050 Electrification: low	46.2	47.2	48.1
PV penetration: ZE-2050 Electrification: high	46.4	47.3	48.2

(millions)	Energy-based	Hybrid	Capacity-based
PV penetration: BaU Electrification: low	118.8	119.4	119.9
PV penetration: ZE-2050 Electrification: low	118.4	119.2	119.9

Figure 7-5 – Annual network tariff collection in 2025 from residential (top left), small commercial (top right) and large commercial + small + large industrial (bottom) the different scenarios and for three different network tariff designs

In light of these first results, higher PV penetration rates under energy-based network tariffs do not appear as a major risk for grid financing. Such risk materialises in minor aspects for the largest consumers (under no average annual electricity consumption for these segments). But for residential customers, which account for half of the annual revenues, the potential losses due to higher distributed PV penetration are largely compensated by the expected increase of average annual electricity consumption in this segment due to the electrification of mobility and heating needs.

This statement is true for the different PV penetration rates and electrification rates considered in our scenarios but as shown in Figure 7-6 and Figure 7-7, the PV penetration rates and electrification rates combinations that would result in revenue losses for grid operators by 2025 and 2030 under an energy-based network tariff design are barely realistic especially by the 2030 time horizon.

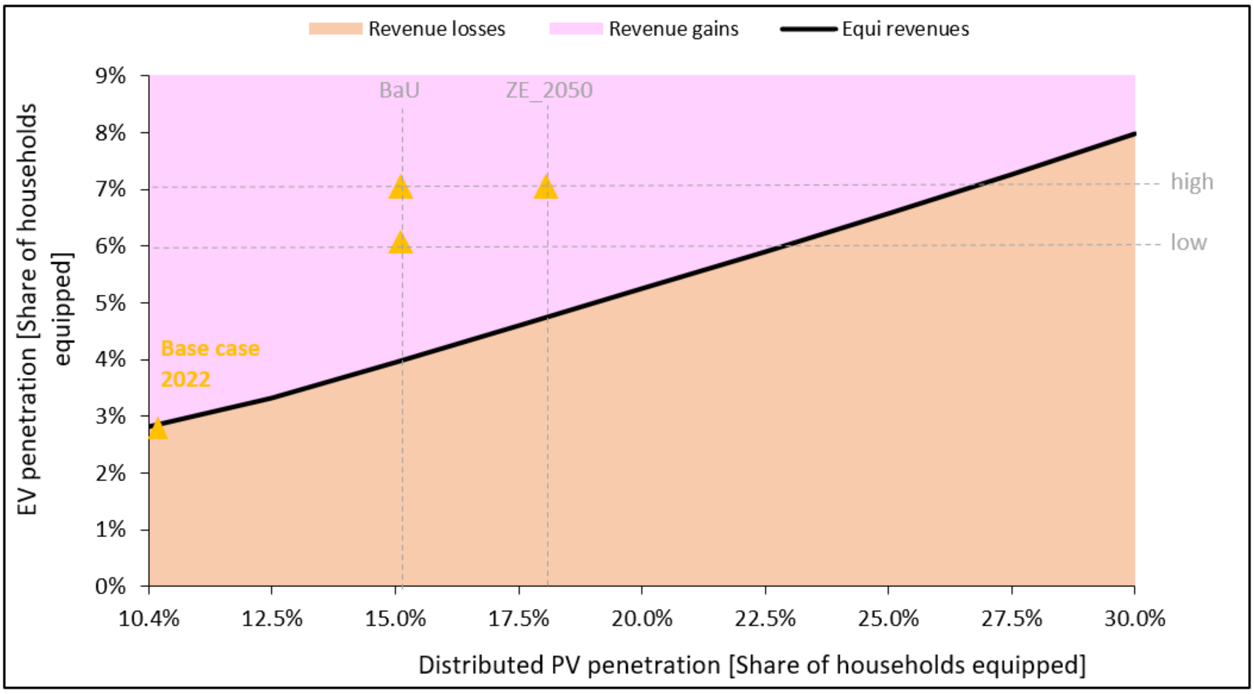


Figure 7-6 - PV penetration & EV penetration combinations that ensure constant revenues from residential customers in 2025 compared to the 2022 base case under energy-based network tariff design.

Note: HP penetration is assumed constant from 2022 to 2025 for this representation

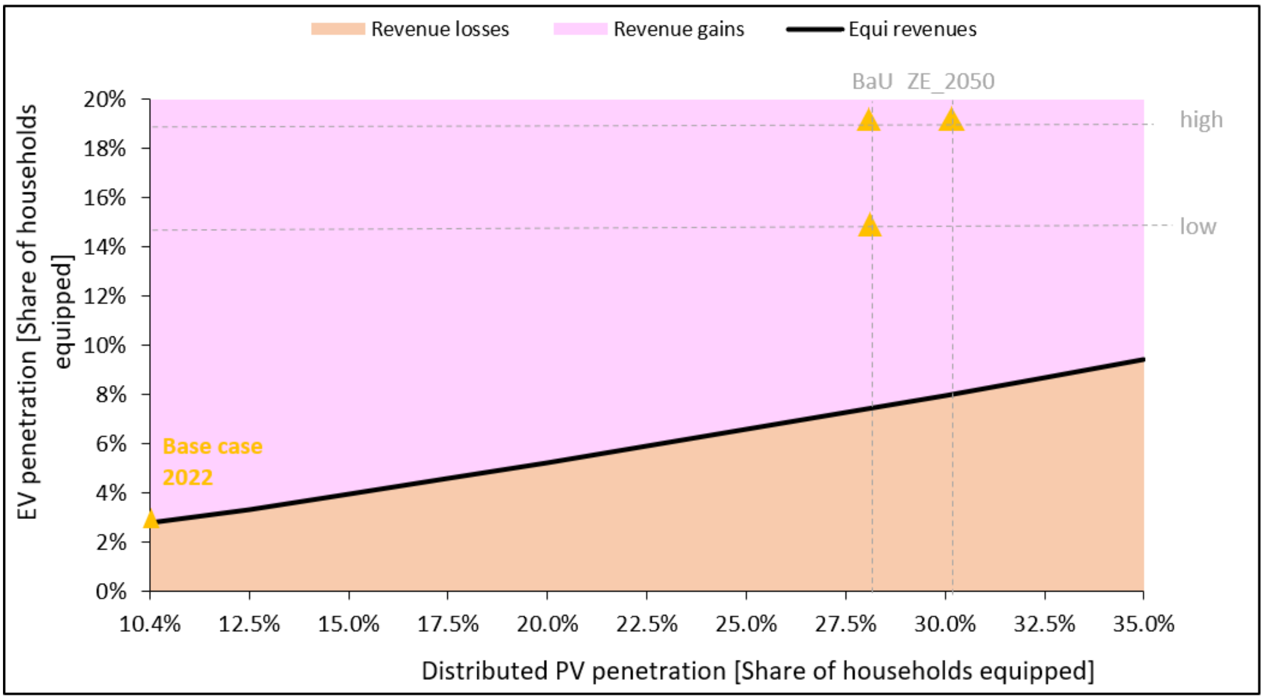


Figure 7-7 - PV penetration & EV penetration combinations that ensure constant revenues from residential customers in 2030 compared to the 2022 base case under energy-based network tariff design.

Note: HP penetration is assumed constant from 2022 to 2030 for this representation

Looking back at the revenues collected from all electricity consumers through network tariffs, the general trend is an increase of revenue regardless of the scenario. The general trends are highly influenced by the ones observed for the residential segment as residential customers contribute to around half of the total revenues (in the 2022 base case).

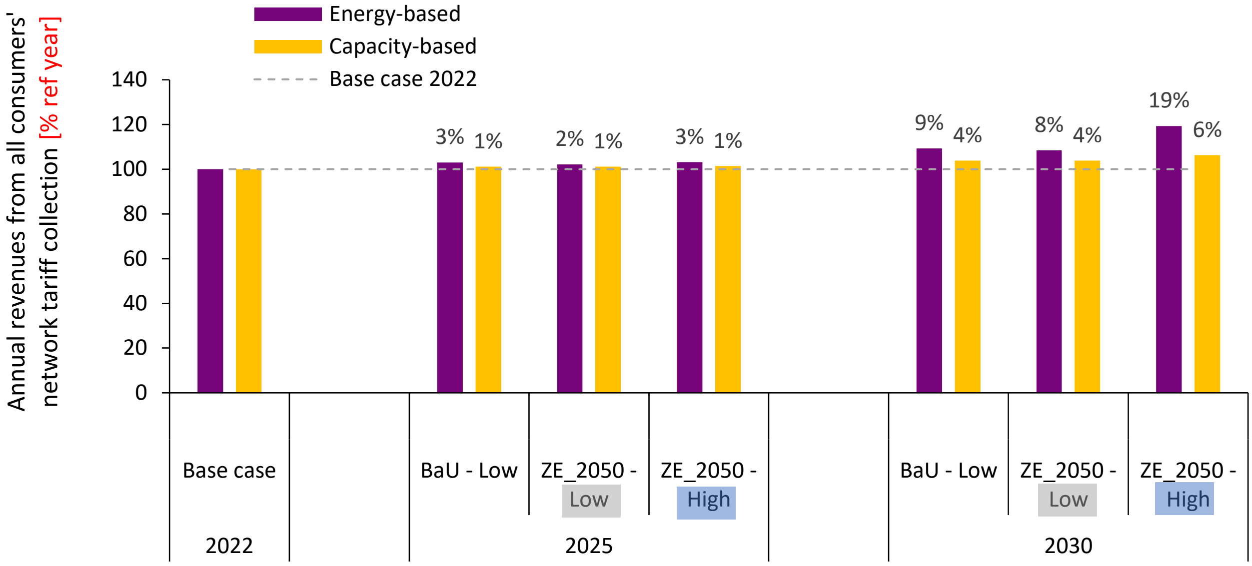


Figure 7-8 - Annual revenues from network tariff collection for all customer segments in the different scenarios and for two different network tariff designs

Overall, energy-based tariffs do not appear as a threat for grid operators' revenues in a context of higher PV penetration but rather as an adequate frame to seize the opportunity of electrification of heating and mobility needs. However, this conclusion is only based on the grid operators' perspectives. Additional questions should be considered such as how fairly grid financing costs are distributed across electricity consumers, to what extent do different network tariffs design incentivize the electrification of heating and mobility needs and to what extent network tariffs design incentivize the investment in a PV system for self-consumption (addressed in the next section). Based on these additional elements that come into play, the most optimal network tariff designs might be a **hybrid combination** of energy-based and capacity-based tariffs.

7.2 Impacts on distributed PV profitability

Here we study how higher PV penetration rates may impact the profitability of distributed PV installations under different boundary conditions.

The impact of higher PV penetration rates on electricity market prices which can in turn impact PV profitability is considered in this report. In the case of distributed PV, no direct exposure to electricity market hourly prices is considered. Yet, in the case of absence of support scheme for excess electricity injected to the grid, or after the support scheme duration is over, excess electricity is sold to a utility which offers a certain price for it. The price is typically a fixed price which may be revised on a monthly basis. Thus, it reflects electricity market prices and their evolution under higher PV penetration rates conditions. This is taken into account in the results presented in the following pages.

Indirect impacts of higher PV penetration as well as different boundary conditions have also been tested. In particular, distributed PV profitability has been assessed under the following different boundary conditions:

- **Network tariffs design:** energy-based and capacity-based network tariffs are analysed. As seen, from a grid financing perspective, the choice between energy-based and capacity-based tariffs seems to go in the direction of energy-based tariffs. However, equitable distribution of the contribution to grid financing between different customer types requires the consideration of other aspects. A network tariff design based on capacity is already implemented in some EU countries and other Member States and regions have already announced plans to switch to such tariffs (e.g. Flanders in Belgium). (See Table 5-1) Assumptions on other components of the electricity bill for the different electricity consumers can be found in Appendixes (-> Sensitivity analysis

7.2.1.1 Sensitivity to higher commodity prices

In the last months, electricity market prices have reached record highs thus impacting the commodity component of retail electricity prices. This trend is a result of a combination and succession of different extraordinary situations: electricity demand surge due to economic activity recovery in all regions of the world as well as the current geopolitical context of war in Ukraine. It can be expected that this conjunctural situation will only impact profitability on the short-term, however it is worth conducting a sensitivity analysis of PV profitability for distributed PV systems to different commodity price increase amplitudes and price increase durations.

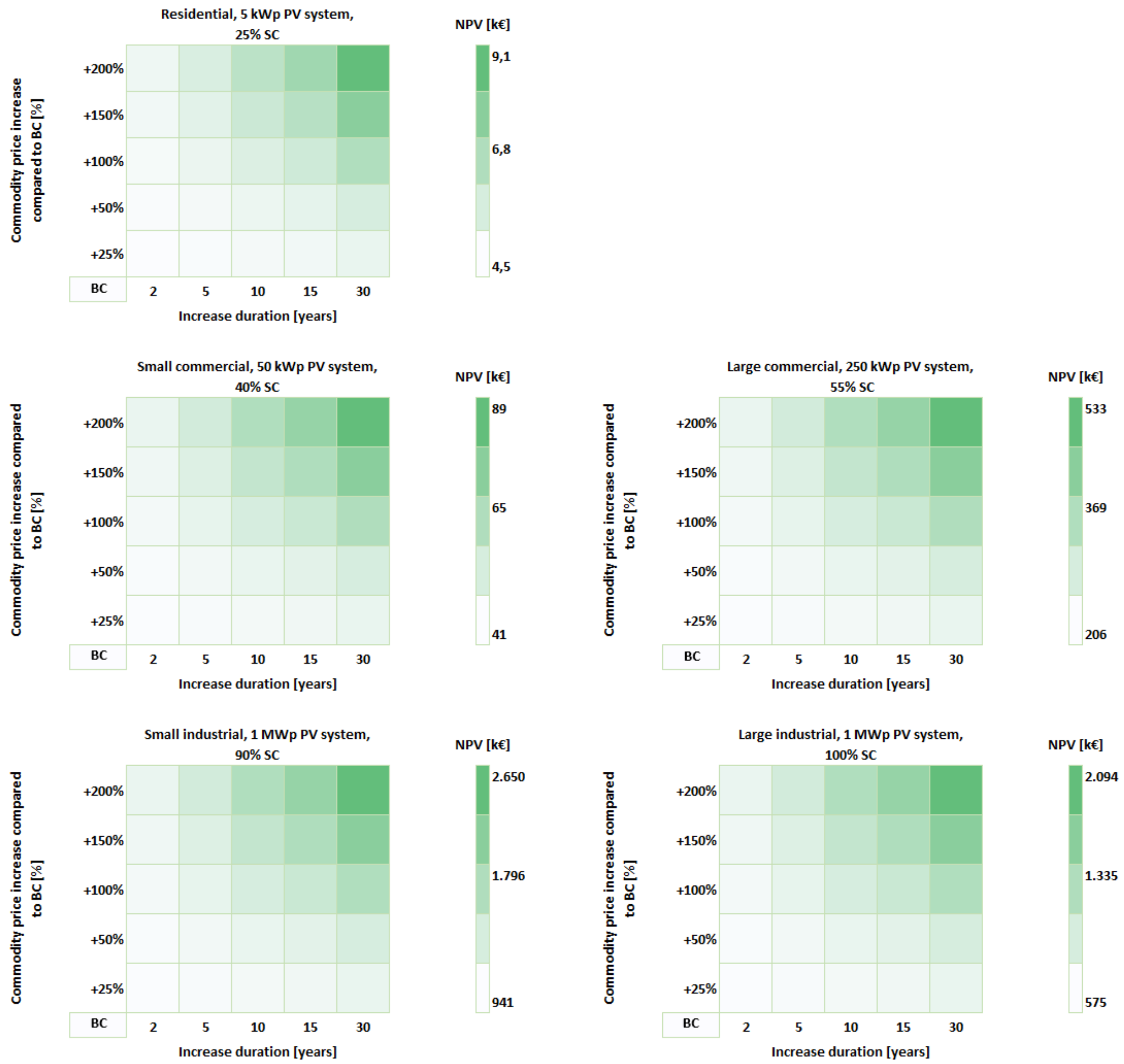


Figure 7-10 - Sensitivity of different distributed PV profitability to different commodity prices amplitudes and durations

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

Unsurprisingly, rising commodity prices benefit greatly to the competitiveness of distributed PV systems. In addition, the higher the self-consumption rates, the more savings on the electricity bill can be increased.
In addition, for residential PV systems, the impact of rising commodity prices is investigated under different CAPEX increases to reflect the current trends of rising raw materials and logistics costs largely leading together to higher PV system costs and to assess to what extent, rising commodity prices have compensated to negative impact of higher PV system prices.

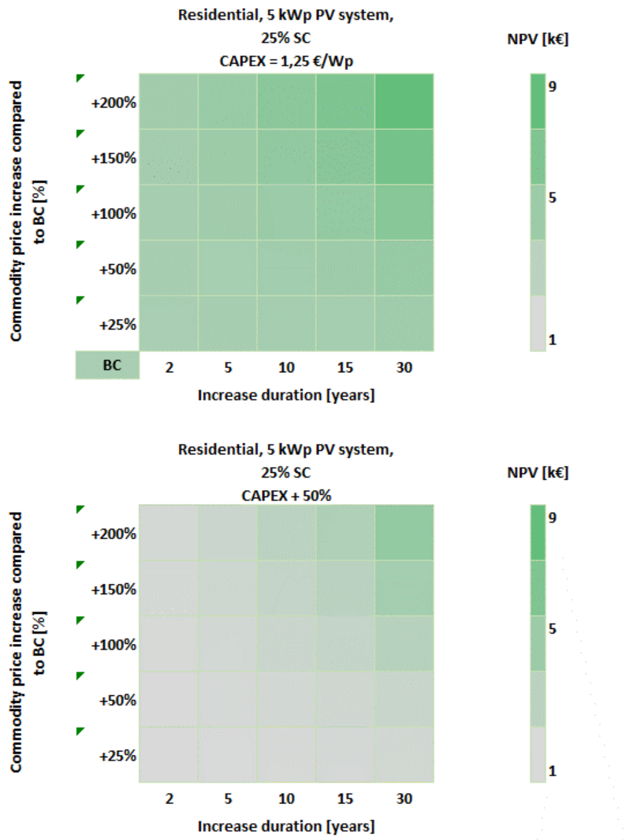


Figure 7-11 - Sensitivity of residential PV profitability to different commodity prices amplitudes and durations under different CAPEX increases with assumed self-consumption rate of 25%

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

With an assumed self-consumption rate of 25% for a residential PV system, a 25% CAPEX increase is compensated by a 100% commodity price increase during 18 years, a 150% increase for 10 years of a 200% increase for 7 years.

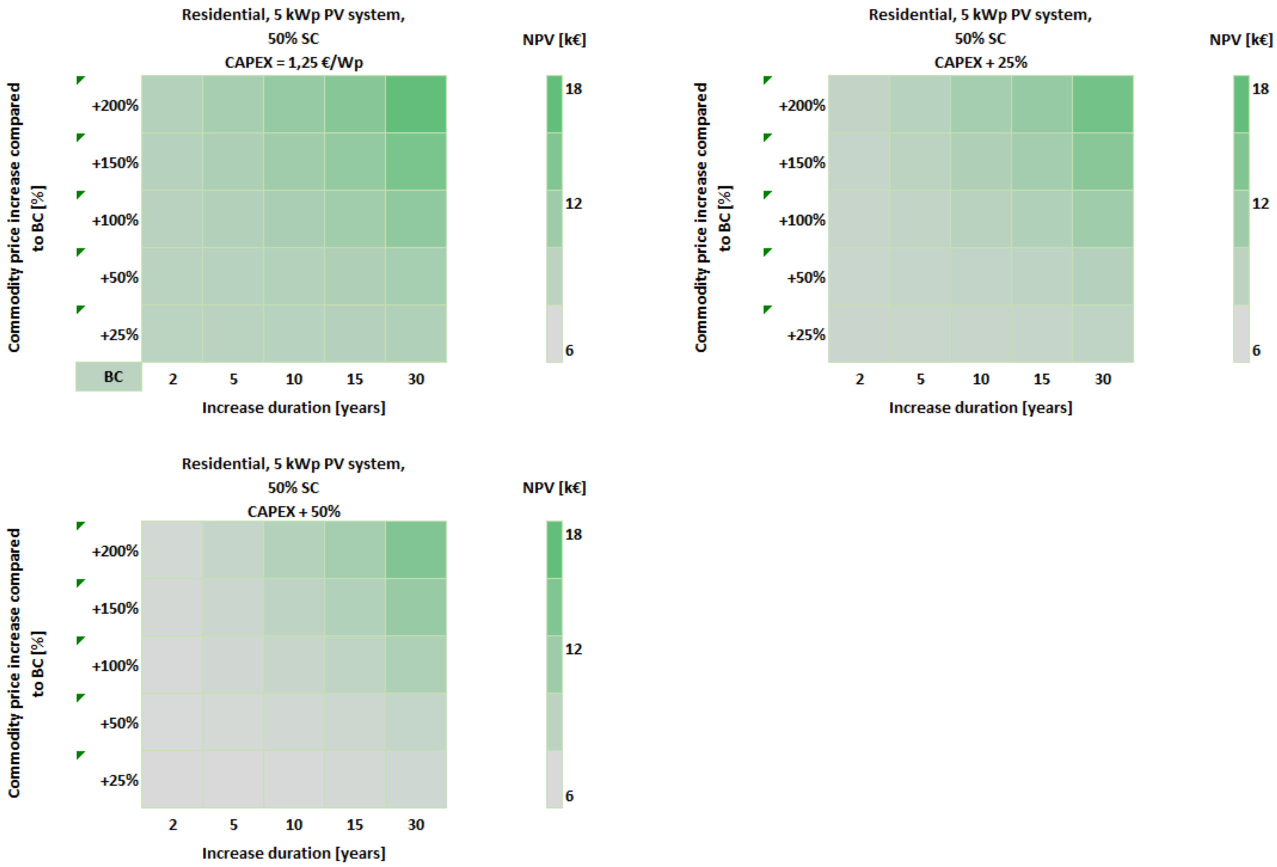


Figure 7-12 - Sensitivity of residential PV profitability to different commodity prices amplitudes and durations under different CAPEX increases with assumed self-consumption rate of 50%

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

With an assumed self-consumption rate of 50% for a residential PV system, a 25% CAPEX increase is compensated by a 100% commodity price increase during 8 years, a 150% increase for 5 years of a 200% increase for 3 years.

7.3 Impacts on centralised PV profitability

Here we study how higher PV penetration rates may impact the profitability of centralised PV installations under different boundary conditions.

The direct impact of higher PV penetration which is considered here is the impact of higher PV penetration rates on electricity market prices which can in turn impact PV profitability. In the case of centralised PV, direct exposure to electricity market hourly prices is considered.

Indirect impacts of higher PV penetration as well as different boundary conditions have also been tested. In particular, centralised PV profitability has been assessed under the following different boundary conditions:

- **Irradiation conditions**: yearly average irradiation ranging from 900 kWh/m².a to 2100 kWh/m².a (See Table 7-1)
- **PV system orientation:** West, East and South
- **Business models**: considered business models are merchant PV and fixed-price PPA. These two business models reflect two opposites in terms of risk. In order to take into account intermediate situations which could for example correspond to other variations/designs of PPAs such as cap-and-floor PPAs, various hybrid combinations of fixed-price PPA and merchant-based PV are tested.
    - Typically, fixed-price PPA will be found at a price that is lower than the average yearly wholesale price so that there is an interest for the power purchaser. In the following results, we consider that under the PPA business model, electricity is valued as at a fixed value of 50 €/MWh.
    - Under the merchant PV business model, electricity is valued at a selling price which corresponds to the weighted average between hourly wholesale prices and hourly PV production.

Studied boundary conditions cover a wide range of options. In the case of results concerning projects initiated in 2025 or 2030, this allows to explore different plausible boundary conditions, thus avoiding the necessity to make too restrictive assumptions on the evolution of these boundary conditions.

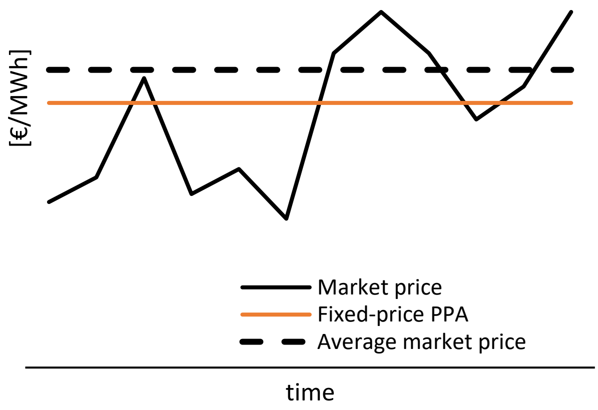
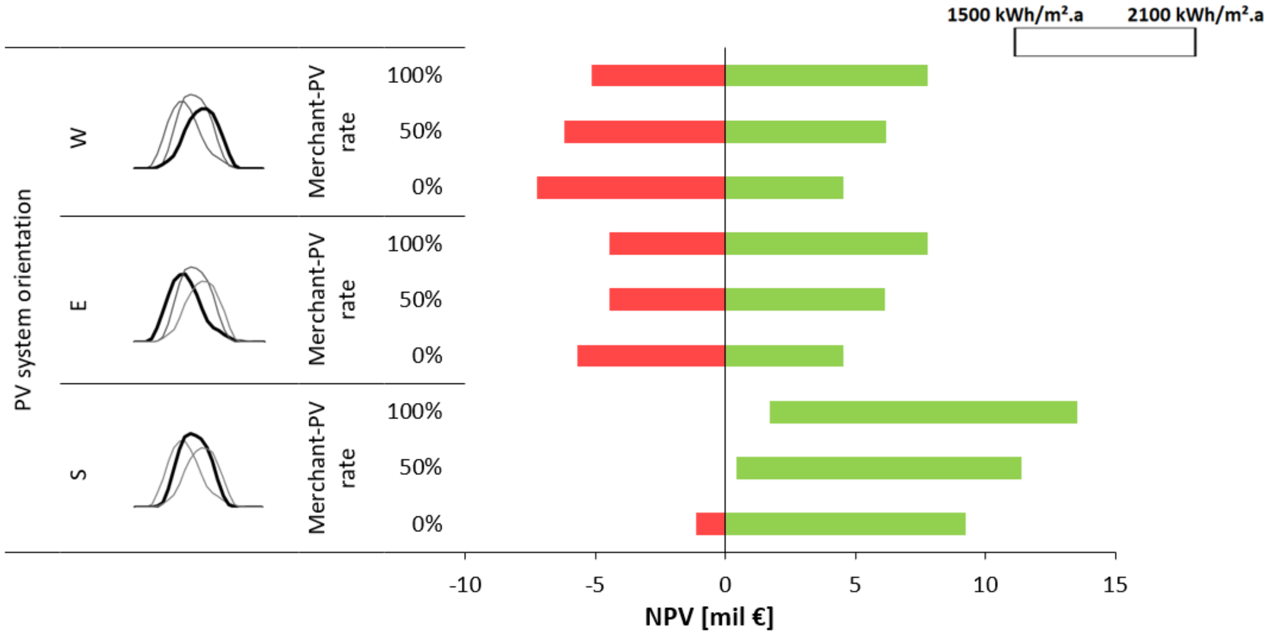


Figure 7-13 - Illustration of differences between market prices, fixed-price PPAs and average market price

7.3.1 Results

- **Base case – projects starting in 2022 – BaU, high adaptation scenario**

First, results for the base case (i.e., PV projects starting in 2022 under a BaU, high adaptation scenario) are presented.



It appears that under a fixed-price PPA + merchant PV business model and under considered assumptions, only the highest irradiations yield positive NPVs for all three orientations.

Looking specifically at the impact of different orientations on the NPV results, it appears that the negative impact of the east and west orientations (lower annual production compared to the south-oriented PV system) outweighs the potential positive impact which is to be exposed to the prices earlier in the morning and later in the afternoon which are on average higher.

Looking specifically at the impact of different business models on the NPV results, it appears that under considered assumptions, the merchant-PV business model is more attractive than the fixed-price PPA. It should be noted that these results are most certainly not applicable to currently observed market trends, as in this Task we base the base case on price trends prior to the exceptional and multifactorial (Covid, and invasion in Ukraine) turmoil/volatility. Trends which are currently witnessed on electricity markets will be explored as part of the sensitivity analysis.

- **BaU results for projects starting in different years**

The impact of assumptions taken for decreasing PV system prices is more important than decreasing selling prices under the BaU scenario

- **Results for different scenarios for projects starting in 2025**

The best NPV results in the ZE_2050 High scenario are 50 000 to 150 000 € higher compared to the best NPV results in the ZE_2050 Low scenarios thanks to a reduced number of hours with negative prices.

In the ZE_2040 scenario, the merit order effect is more important, thus making the attractiveness of merchant PV over the 50 €/MWh PPA fixed price less straightforward.

7.3.2 Sensitivity analysis

7.3.2.1 Sensitivity to electricity market prices

Here, coupled sensitivity analysis are conducted. The impact of electricity market prices variations has been already studied through the different scenarios and time horizon. However, here we look more specifically at some possible trends, covering a larger range of possibilities and how they would impact PV profitability. As far as CAPEX variations are concerned, both rising and decreasing CAPEX are studied. Indeed, while the growing PV penetration rates and thus, PV market allow to move forward on the learning curve for its different components and to reach lower costs, as witnessed in the recent months, the single premise that PV components will carry on getting cheaper has been challenged. Under increasing PV penetration rates from PV market rapid growth, the supply-demand balance can be altered leading to rising prices.

- **Rising selling prices and rising CAPEX reflecting currently observed disruptions.**

In the last months, electricity market prices have reached record highs. This trend is a result of a combination and succession of different extraordinary situations: electricity demand surge due to economic activity recovery in all regions of the world as well as the current geopolitical context of war in Ukraine. It can be expected that this conjunctural situation will only impact profitability on the short-term, however it is worth conducting a sensitivity analysis of PV profitability for ground mounted systems to different price increase amplitudes and price increase durations. In addition, the impact of rising selling prices is investigated under different CAPEX increases to reflect the current trends of rising raw materials and logistics costs largely leading together to higher PV system costs.

Figure 7-14 - Sensitivity analysis of PV profitability to different selling price increases and increase durations for different CAPEX increases.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with PPA price = 50 €/MWh and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, higher selling prices improve significantly the competitiveness of PV projects. When the CAPEX increases from 0,6 €/Wp to 0,7 €/Wp, the initial NPV can be achieved again with approximately a 200% selling price increase during 2 years or a 100% increase during 5 years under considered conditions.

- **Rising selling prices under different PPA prices.**

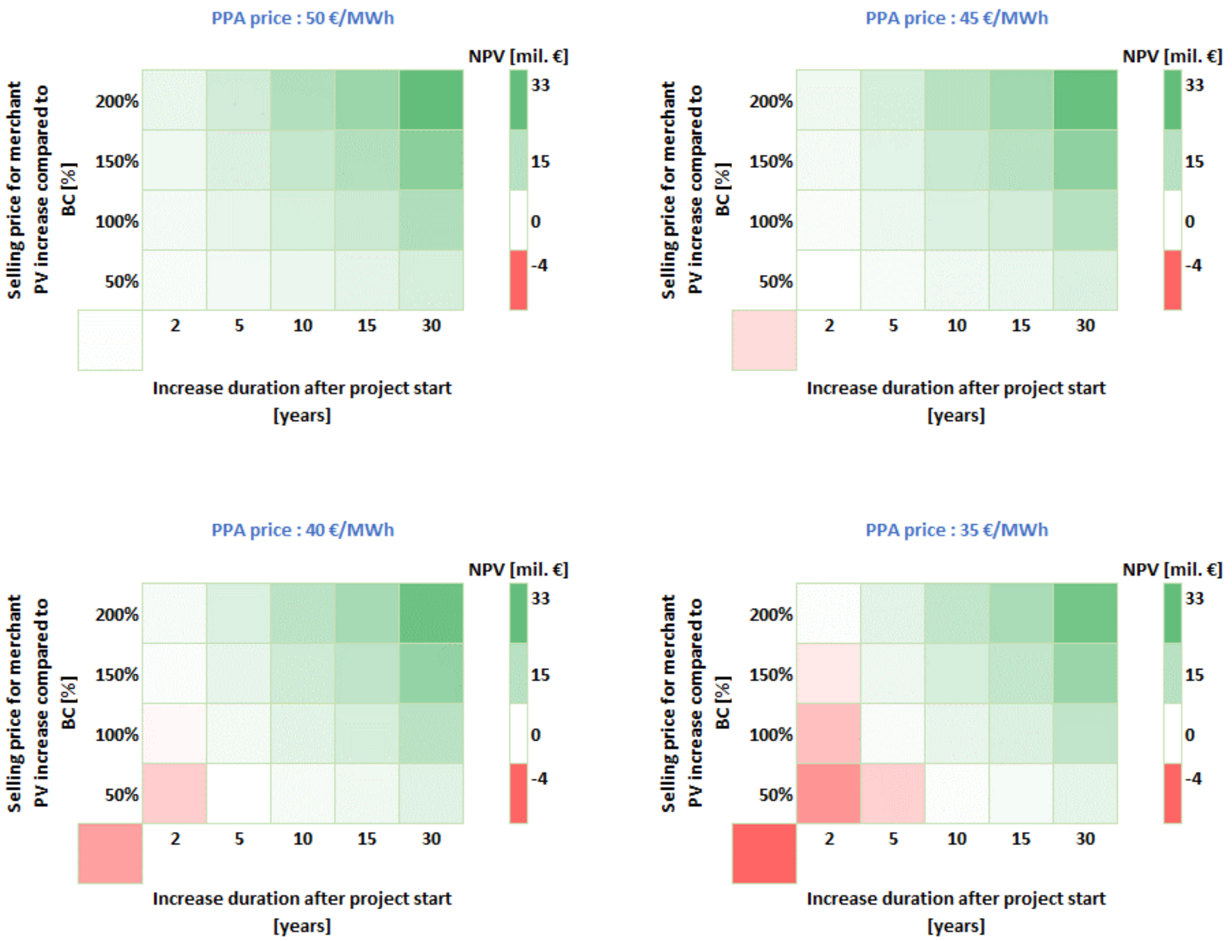


Figure 7-15 - Sensitivity analysis of PV profitability to different selling price increases under different PPA prices.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with CAPEX = 0,6 €/Wp and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, higher selling prices improve significantly the competitiveness of PV projects. When the PPA price decreases from 50 €/MWh to 45 €/MWh, the initial NPV can be achieved again with approximately a 50% selling price increase during 2 years under considered conditions. When the PPA price decreases from 50 €/MWh to 40 €/MWh, the initial NPV can be achieved again with approximately a 50% selling price increase during 5 years or 150% selling price increase during 2 years under considered conditions.

- **Decreasing selling prices reflecting cannibalisation effect and decreasing CAPEX**

Here, a sensitivity analysis of PV profitability for ground mounted systems to different price decrease amplitudes and price decrease durations is conducted. In addition, the impact of decreasing selling prices is investigated under different CAPEX decreases to reflect the learning curve effect which can still be expected for different PV system components in the aftermath of current supply chain turmoil and price hikes.

Figure 7-16 - Sensitivity analysis of PV profitability to different selling price decrease under different CAPEX.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with PPA = 50 €/MWh and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, lower selling prices deteriorate significantly the competitiveness of PV projects, all the more so as selling price start declining soon after project start.

When the CAPEX decreases from 0,6 €/Wp to 0,55 €/Wp, the initial NPV can be achieved again even with approximately a -10% selling price decrease starting 7 years after project start or a -15% selling price decrease starting 12 years after project start under considered conditions.

- **Occurrence of negative prices**

In previously presented results, negative prices are included in the modelling and differ based on the time-horizon (and associated PV penetration rate) and the scenario.

However, these negative prices are only modelled in terms of European average, yet important differences exist from one country to another, even currently, in terms of the occurrence of negative prices as illustrated in Figure 7-17.[30] Thus, this sensitivity analysis aims at covering a broader range of situations.

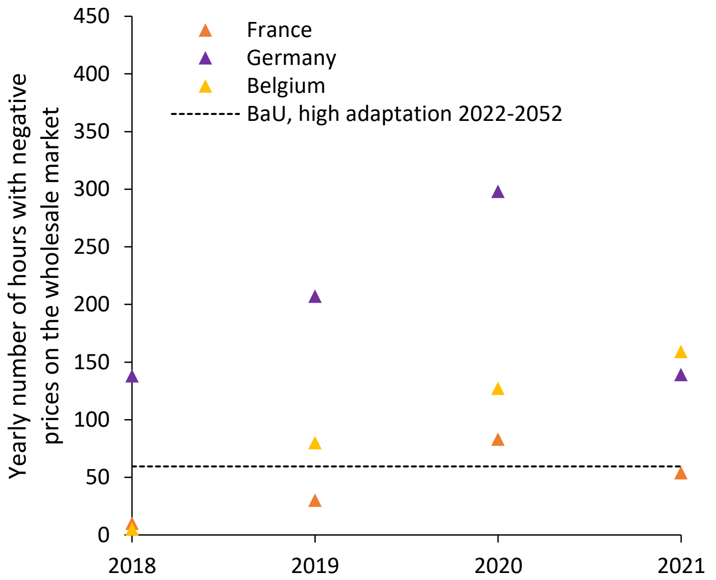


Figure 7-17 - Yearly number of hours with negative prices on the wholesale market in different EU countries and in the BaU 2022-2052, high adaptation simulated prices.

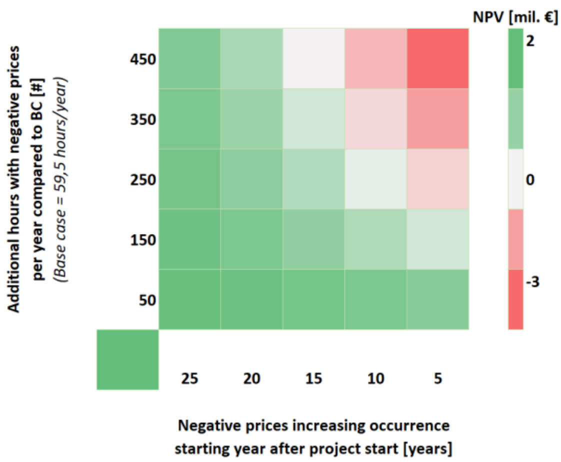


Figure 7-18 - Sensitivity analysis of PV profitability to different negative prices hours occurrence increase.

Notes:

- *Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 100% merchant PV business model and under the BaU, high adaptation scenario for a project starting in 2022.*
- *Additional hours with negative prices refer to hours across the 8760 hours of the year. Thus, additional assumption is made on the share of these negative price hours that take place during PV production hours. For N hours with negative prices per year, it is assumed that 30%*N full load hours equivalent of PV are taking place during negative prices episodes. Negative price is assumed to be -25€/MWh on average and full load hours are assumed to amount to 1000 hours.*

- For the considered case, the higher occurrence of negative prices starts to jeopardize PV profitability starting with 450 additional hours of negative prices per year after 15 years of project, or 250 additional hours of negative prices per year after 10 years. Overall, most additional negative hours under considered assumptions take place during the night or during hours when PV production is non-existent or low. Therefore, the overall impact on PV profitability is low.

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- **Self-consumption**: self-consumption rates ranging from 0% to 100% are studied. The increasing penetration of heat pumps and electric vehicles, makes it even more challenging to define a unique typical self-consumption rate per electricity consumer category (residential, commercial, …). Therefore, presenting the results for a wide range of self-consumption rates allows to depict the impact on PV profitability in different cases.
- **Irradiation conditions**: yearly average irradiation ranging from 900 kWh/m².a to 2100 kWh/m².a

Table 7-1 – Exact locations and average yearly irradiations associated with the five studied irradiation conditions

e.g., all references to the average yearly irradiation of 1200 kWh/m².a correspond to a system in Stockholm, Sweden with an average yearly irradiation of 1223 kWh/m².a

Country	City	Exact average yearly irradiation used in calculations [kWh/m².a]	Rounded average yearly irradiation used in legends and chart axis [kWh/m².a]
Norway	Tromsø	904	900
Sweden	Stockholm	1223	1,200
Austria	Vienna	1476	1,500
Italy	Pisa	1817	1,800
Spain	Madrid	2101	2,100

- **Business models**: considered business models are: 1) a 20-year fixed feed-in tariff, 2) a one-shot investment aid and 3) unsubsidized distributed PV.

Table 7-2 - Overview of business models considered for distributed PV

PV System consumer category	Business model 1: **Feed-in tariff**	Business model 2: **Investment aid**	Business model 3: **Unsubsidized**
Residential	**Years 1 to 30**: Self-consumption: allowed **Years 1 to 20**: feed-in tariff (0,08 €/kWh) **Years 21 to 30**: excess electricity is valued at wholesale market price (contract signed with a utility)	**Year 0**: one-shot investment aid received (275 €/kWp) **Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)	**Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)
Small commercial	**Years 1 to 30**: Self-consumption: allowed **Years 1 to 20**: feed-in tariff (0,075 €/kWh) **Years 21 to 30**: excess electricity is valued at wholesale market price (contract signed with a utility)	**Year 0**: one-shot investment aid received (215 €/kWp) **Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)	**Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)
Large commercial	**Years 1 to 30**: Self-consumption: allowed **Years 1 to 20**: feed-in tariff (0,07 €/kWh) **Years 21 to 30**: excess electricity is valued at wholesale market	**Year 0**: one-shot investment aid received (181 €/kWp) **Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)	**Years 1 to 30**: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)

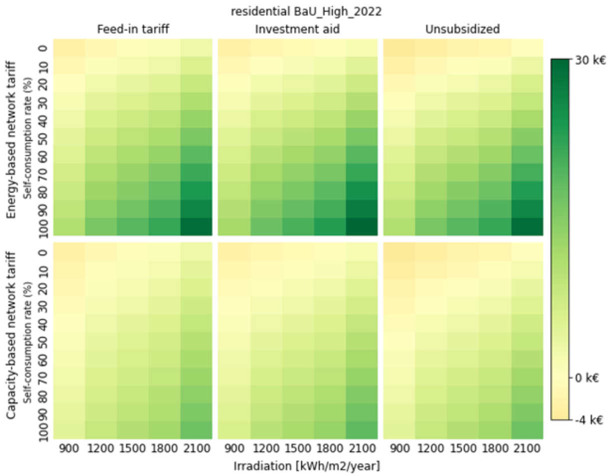
	price (contract signed with a utility)		
Small & Large industrial	<u>**Years 1 to 30**</u>: Self-consumption: allowed <u>**Years 1 to 20**</u>: feed-in tariff (0,065 €/kWh) <u>**Years 21 to 30**</u>: excess electricity is valued at wholesale market price (contract signed with a utility)	<u>**Year 0**</u>: one-shot investment aid received (173 €/kWp) <u>**Years 1 to 30**</u>: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)	<u>**Years 1 to 30**</u>: Self-consumption: allowed & excess electricity is valued at wholesale market price (contract signed with a utility)

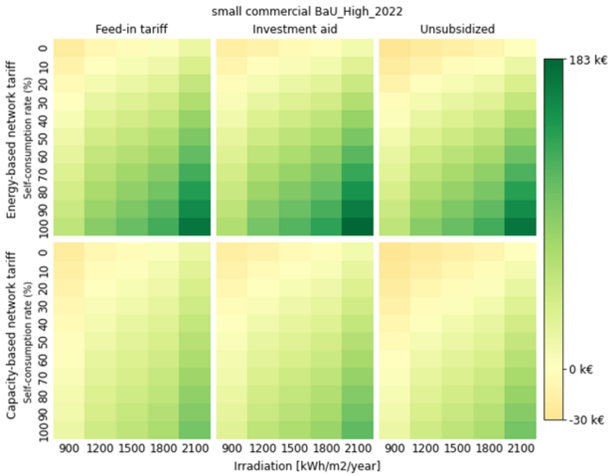
Studied boundary conditions cover a wide range of options. In the case of results concerning projects initiated in 2025 or 2030, this allows to explore different plausible boundary conditions, thus avoiding the necessity to make too restrictive assumptions on the evolution of these boundary conditions.

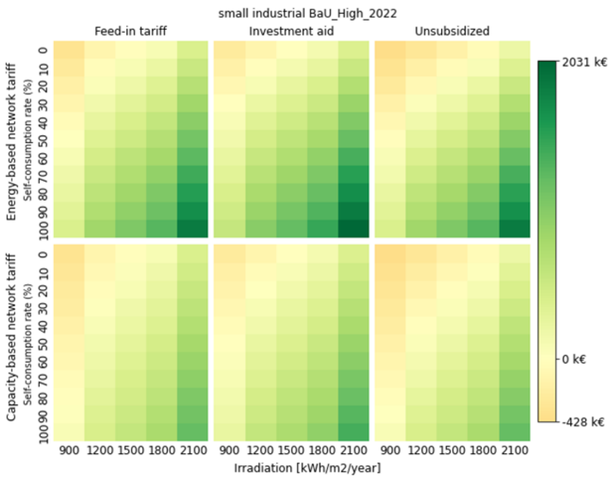
7.3.3 Results

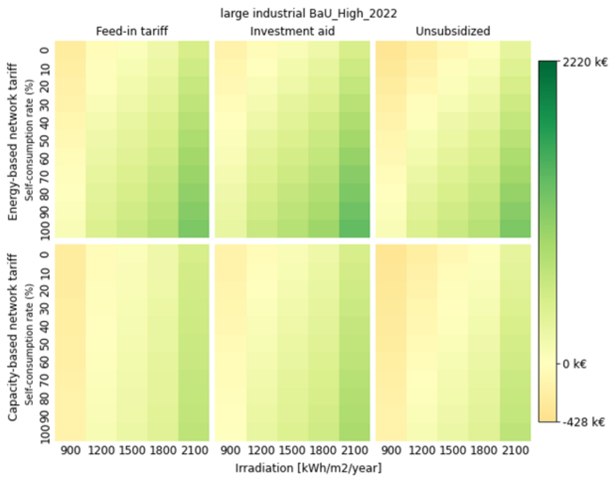
Plotted results provide the NPV of the PV project over with an assumed 30-year lifetime.

Base case – projects starting in 2022 – BaU, high adaptation scenario









Under energy-based network tariffs, PV systems with high self-consumption rates are a no brainer from an economic point of view even with retail electricity prices at their early 2020 level and even under an unsubsidized business model. Indeed, under this business models, self-consumption rates above 40% for the locations with the poorest irradiation conditions (900 kWh/m².a) and above 10% for the locations with the best irradiation conditions (2100 kWh/m².a) are sufficient to achieve break-even under energy-based network tariffs.

Under capacity-based network tariffs, due to the reduced economies on the electricity bill potential, higher self-consumption rates are required to reach the same level of competitiveness. However, in the case of electricity consumers with an important electricity consumption compared to the average in their consumer category (e.g., residential consumer which have electrified their mobility and heating/cooling needs with the purchase of an electric vehicle and a heat pump), it is also worth looking at the total electricity bill rather than only at savings on this later. Indeed, for PV owners with flexibilities (i.e., heat pumps and/or electric vehicles), while the energy-based network tariffs allow to reach better NPV results, it also increases the annual bill for network tariffs for the remaining electricity needs (after self-consumption). However, it appears that the positive impact on the NPV outweighs the negative impact on the annual bill for network tariffs under the considered assumptions. This is illustrated in Figure 7-9.

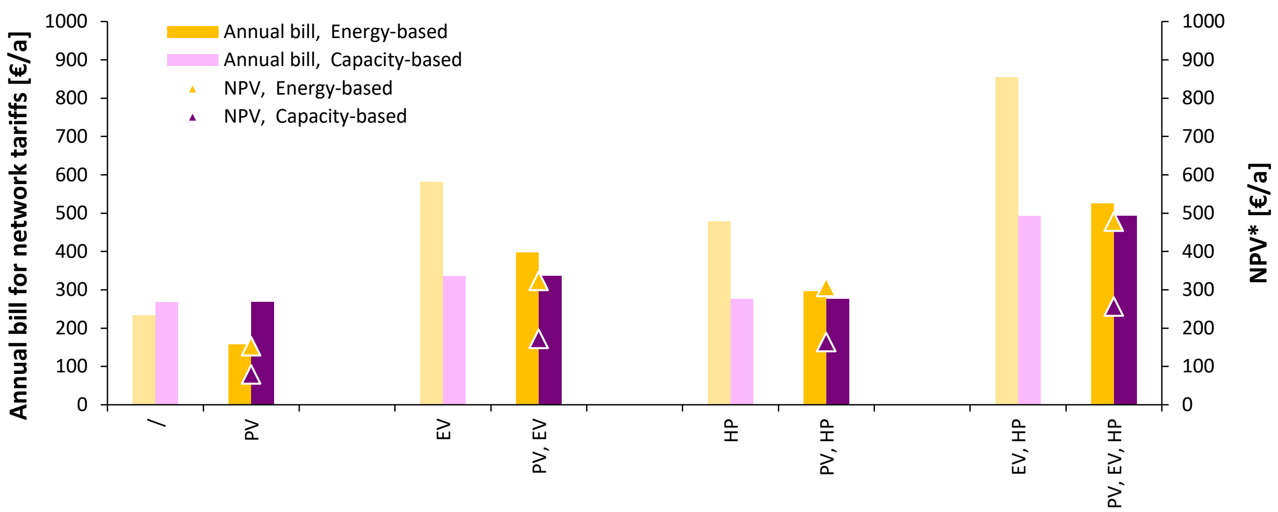


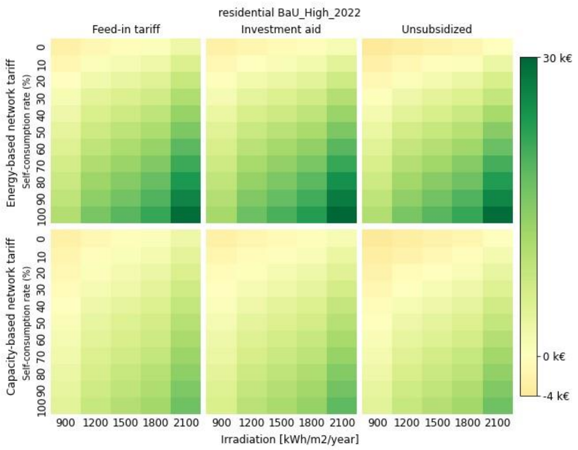
Figure 7-9 – Comparison of annual bill for network tariffs and annual NPV under different network tariff designs and for different types of residential consumers

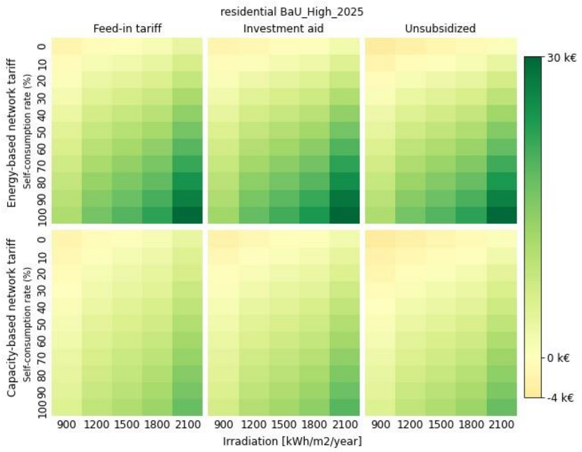
Notes:

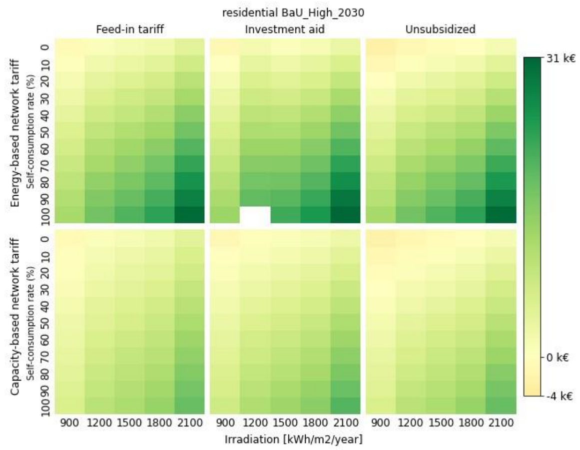
- **NPV calculated for 30 years and then converted into annual value*
- *When a PV system is considered, calculations have been conducted for a 5 kWp PV system, benefitting from a feed-in tariff and exposed to a 1500 kWh/m².a yearly average irradiation.*
- *Assumptions in terms of annual electricity consumption, annual subscribed power can be found in Table 4-1,*
- *Assumptions related to self-consumption and self-sufficiency rates can be found in Table 4-3,*
- *Assumptions concerning considered capacity-based and energy based tariffs can be found in Table 5-1 (capacity-based tariffs and energy-based tariffs are assumed constant for all consumer categories considered here)*

There is no impact coming from choosing the low or high adaptation scenario as for distributed PV there is no exposure to hourly market prices. Thus, only the results for the high scenario are presented. On the following heatmaps, the assumptions on decreasing CAPEX for the different PV systems outweigh the impact of declining average electricity prices (Merit Order Effect - MoE). Under capacity-based network tariffs, profitability is lower as such tariffs reduced the savings potential on the electricity bill. The higher the self-consumption rate, the lower the dependence to the selected business model and in particular the feed-in tariff compared to the unsubsidized business model. The remaining heatmaps are presented in Appendix (APPENDIXES).

- **<u>Evolution of residential PV profitability through the years under the BaU</u>**

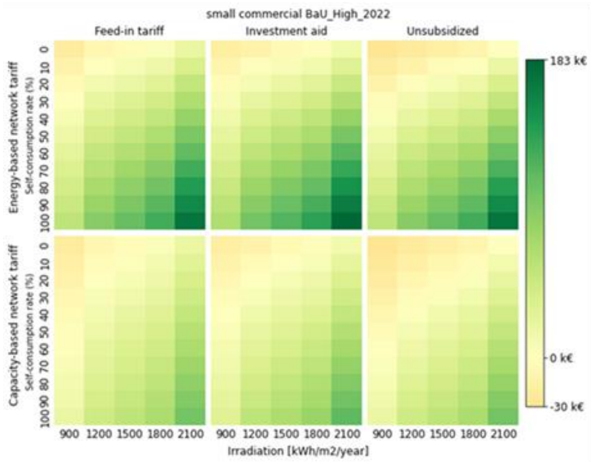




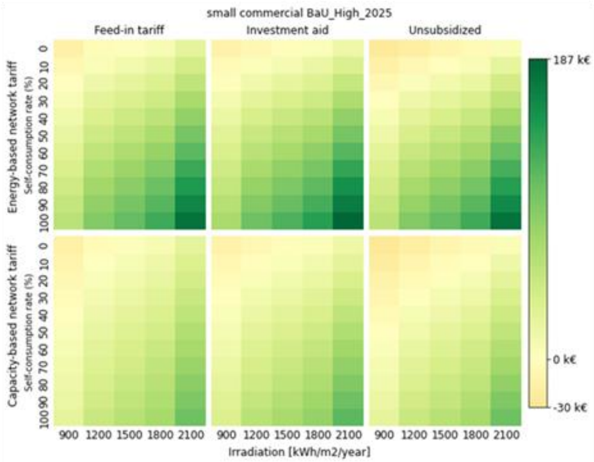


- **Evolution of small commercial PV profitability through the years under the BaU**

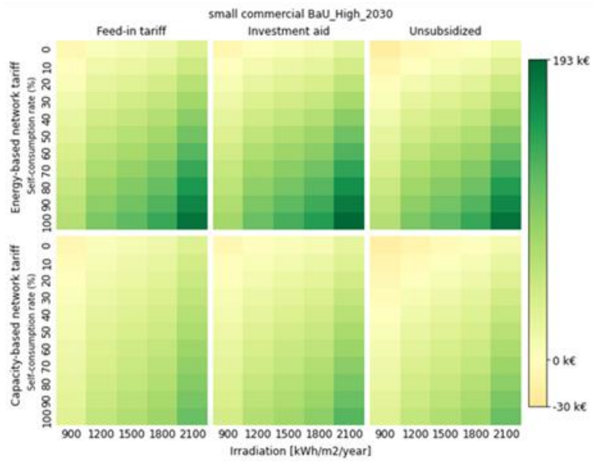
2022



2025

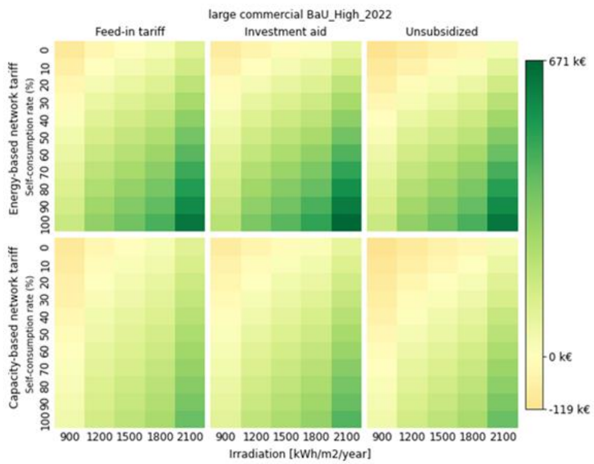


2030

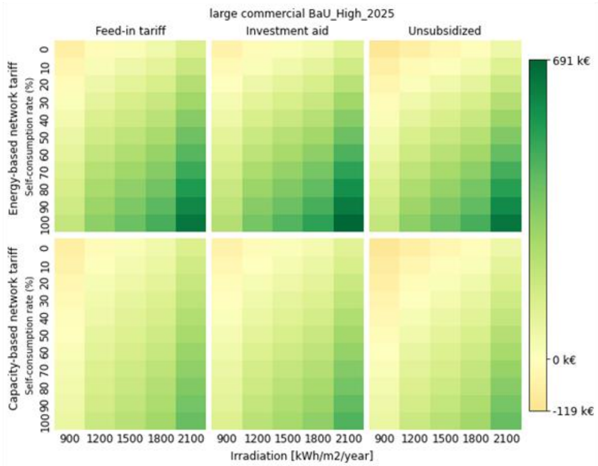


- **Evolution of large commercial PV profitability through the years under the BaU**

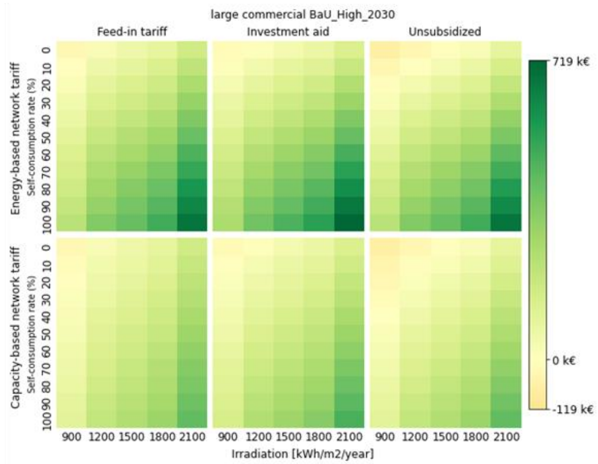
2022



2025

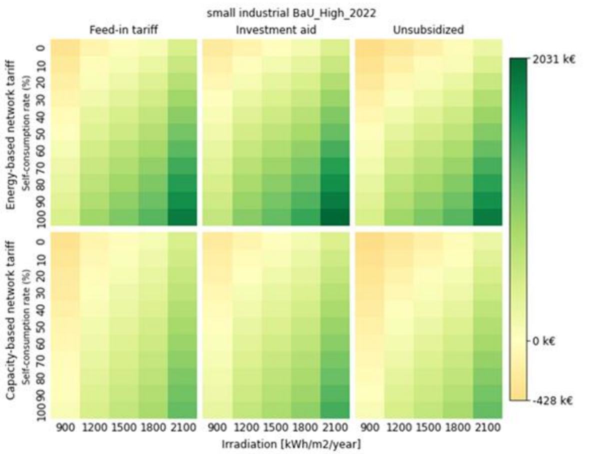


2030

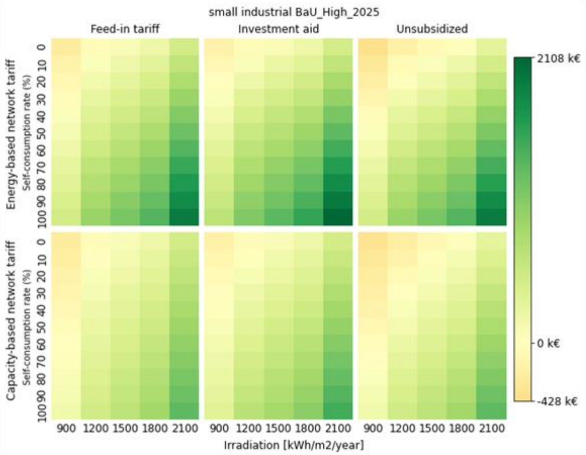


- **Evolution of small industrial PV profitability through the years under the BaU**

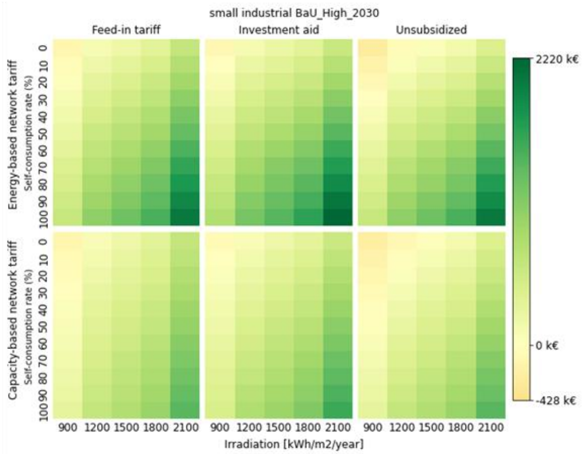
2022



2025

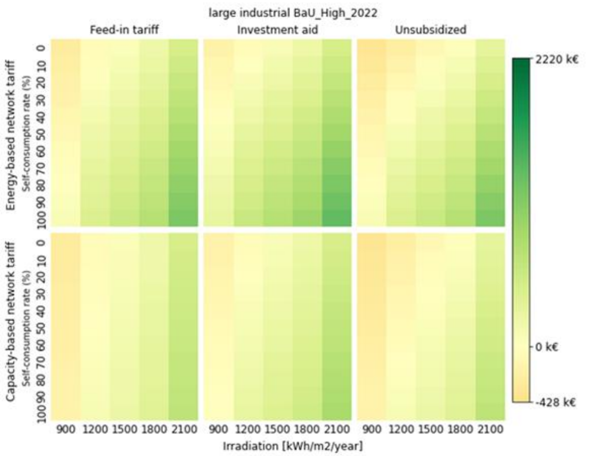


2030

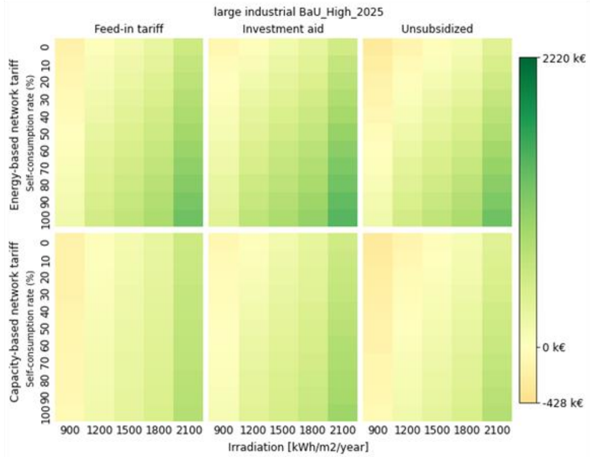


- **Evolution of large industrial PV profitability through the years under the BaU**

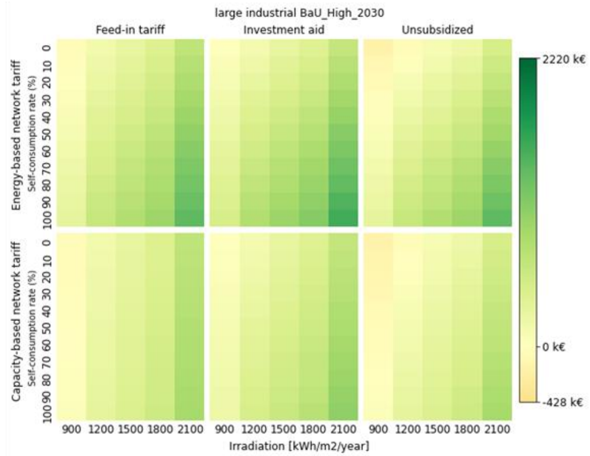
2022



2025



2030



7.3.4 Sensitivity analysis

7.3.4.1 Sensitivity to higher commodity prices

In the last months, electricity market prices have reached record highs thus impacting the commodity component of retail electricity prices. This trend is a result of a combination and succession of different extraordinary situations: electricity demand surge due to economic activity recovery in all regions of the world as well as the current geopolitical context of war in Ukraine. It can be expected that this conjunctural situation will only impact profitability on the short-term, however it is worth conducting a sensitivity analysis of PV profitability for distributed PV systems to different commodity price increase amplitudes and price increase durations.

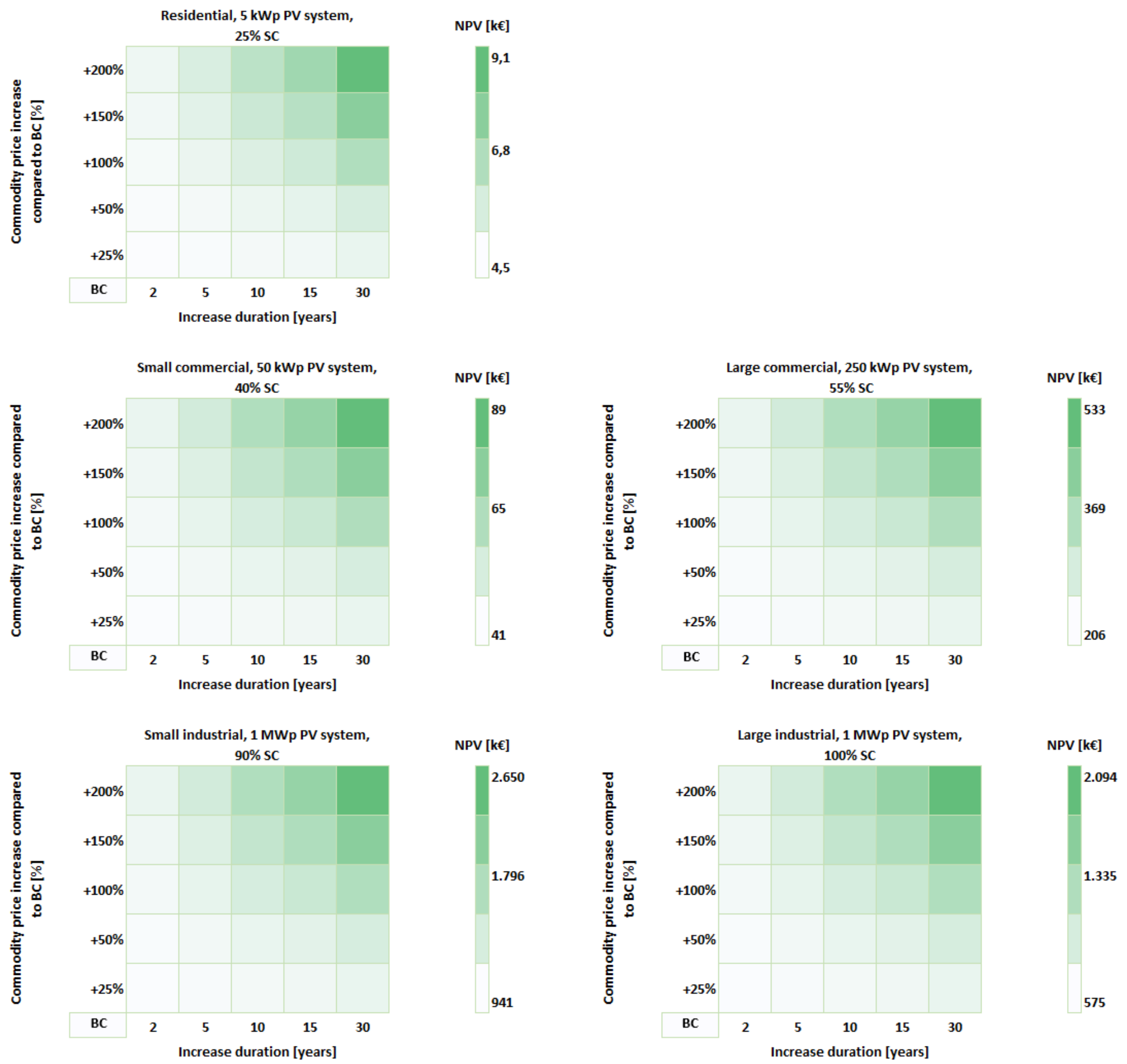


Figure 7-10 - Sensitivity of different distributed PV profitability to different commodity prices amplitudes and durations

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

Unsurprisingly, rising commodity prices benefit greatly to the competitiveness of distributed PV systems. In addition, the higher the self-consumption rates, the more savings on the electricity bill can be increased.

In addition, for residential PV systems, the impact of rising commodity prices is investigated under different CAPEX increases to reflect the current trends of rising raw materials and logistics costs largely leading together to higher PV system costs and to assess to what extent, rising commodity prices have compensated to negative impact of higher PV system prices.

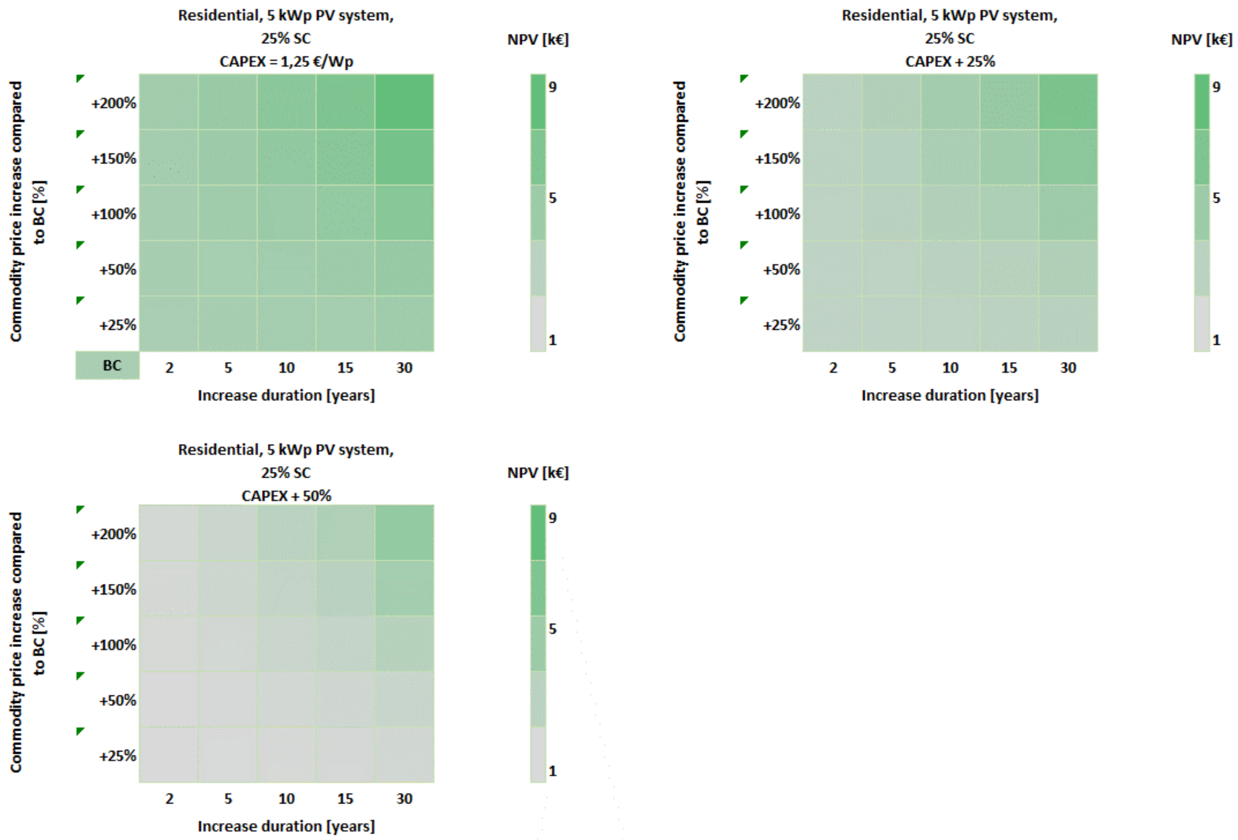


Figure 7-11 - Sensitivity of residential PV profitability to different commodity prices amplitudes and durations under different CAPEX increases with assumed self-consumption rate of 25%

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

With an assumed self-consumption rate of 25% for a residential PV system, a 25% CAPEX increase is compensated by a 100% commodity price increase during 18 years, a 150% increase for 10 years of a 200% increase for 7 years.

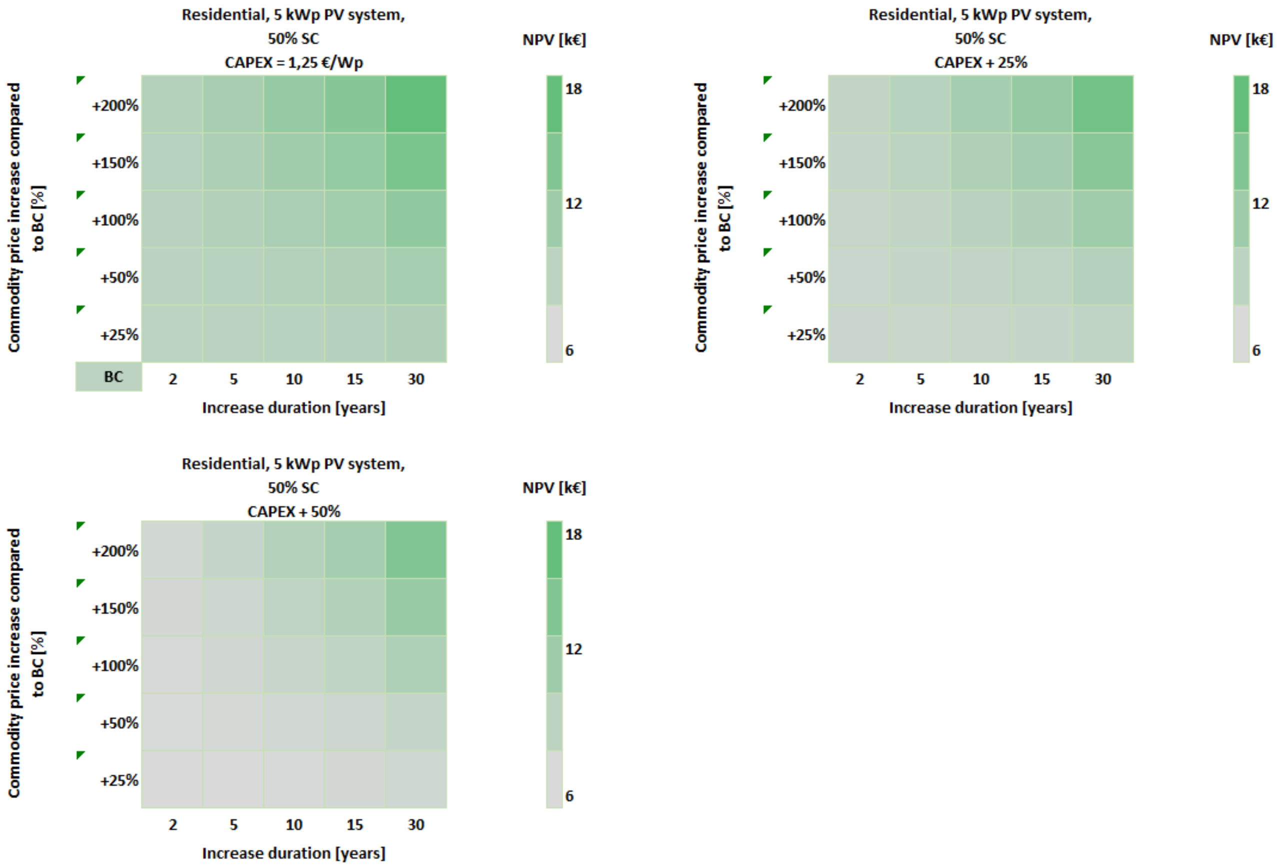


Figure 7-12 - Sensitivity of residential PV profitability to different commodity prices amplitudes and durations under different CAPEX increases with assumed self-consumption rate of 50%

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented rooftop system, under a feed-in tariff support scheme and under the BaU, high adaptation scenario for a project starting in 2022.

With an assumed self-consumption rate of 50% for a residential PV system, a 25% CAPEX increase is compensated by a 100% commodity price increase during 8 years, a 150% increase for 5 years of a 200% increase for 3 years.

7.4 Impacts on centralised PV profitability

Here we study how higher PV penetration rates may impact the profitability of centralised PV installations under different boundary conditions.

The direct impact of higher PV penetration which is considered here is the impact of higher PV penetration rates on electricity market prices which can in turn impact PV profitability. In the case of centralised PV, direct exposure to electricity market hourly prices is considered.

Indirect impacts of higher PV penetration as well as different boundary conditions have also been tested. In particular, centralised PV profitability has been assessed under the following different boundary conditions:

- **Irradiation conditions**: yearly average irradiation ranging from 900 kWh/m².a to 2100 kWh/m².a (See Table 7-1)
- **PV system orientation:** West, East and South
- **Business models**: considered business models are merchant PV and fixed-price PPA. These two business models reflect two opposites in terms of risk. In order to take into account intermediate situations which could for example correspond to other variations/designs of PPAs such as cap-and-floor PPAs, various hybrid combinations of fixed-price PPA and merchant-based PV are tested.
    - Typically, fixed-price PPA will be found at a price that is lower than the average yearly wholesale price so that there is an interest for the power purchaser. In the following results, we consider that under the PPA business model, electricity is valued as at a fixed value of 50 €/MWh.
    - Under the merchant PV business model, electricity is valued at a selling price which corresponds to the weighted average between hourly wholesale prices and hourly PV production.

Studied boundary conditions cover a wide range of options. In the case of results concerning projects initiated in 2025 or 2030, this allows to explore different plausible boundary conditions, thus avoiding the necessity to make too restrictive assumptions on the evolution of these boundary conditions.

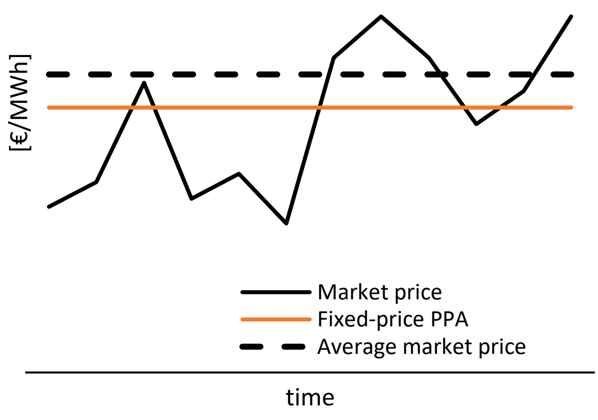
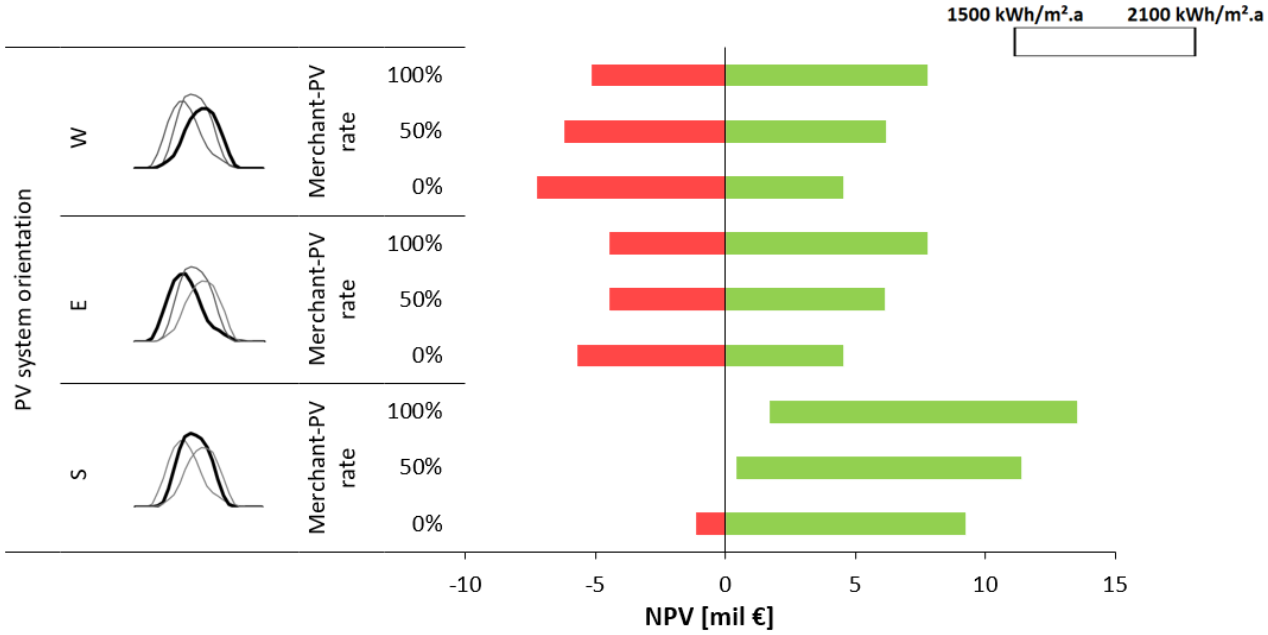


Figure 7-13 - Illustration of differences between market prices, fixed-price PPAs and average market price

7.4.1 Results

- **Base case – projects starting in 2022 – BaU, high adaptation scenario**

First, results for the base case (i.e., PV projects starting in 2022 under a BaU, high adaptation scenario) are presented.

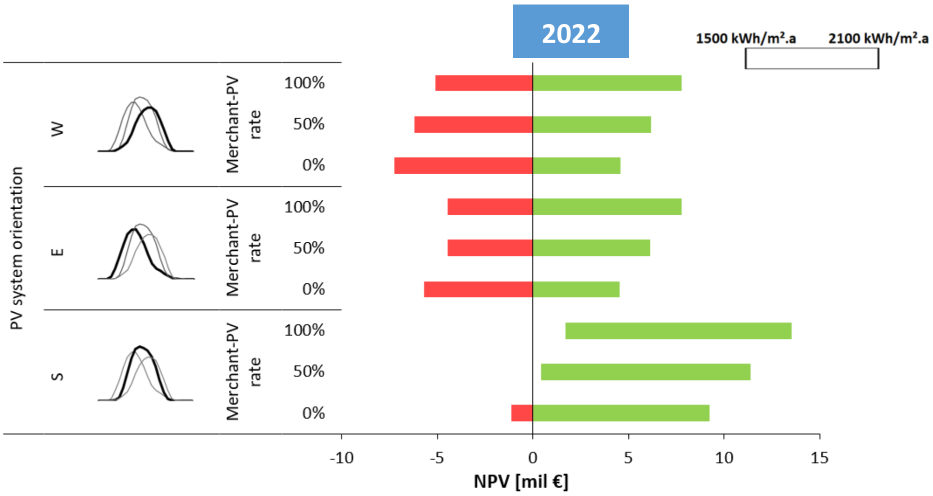


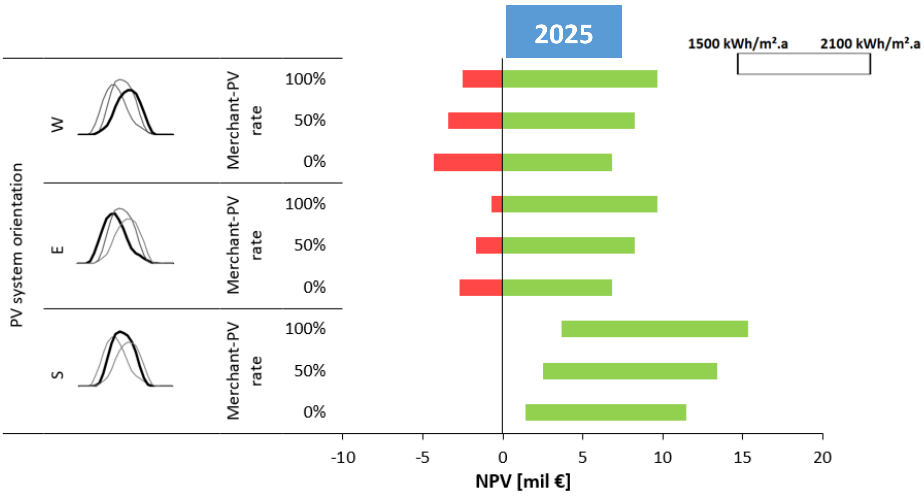
It appears that under a fixed-price PPA + merchant PV business model and under considered assumptions, only the highest irradiations yield positive NPVs for all three orientations.

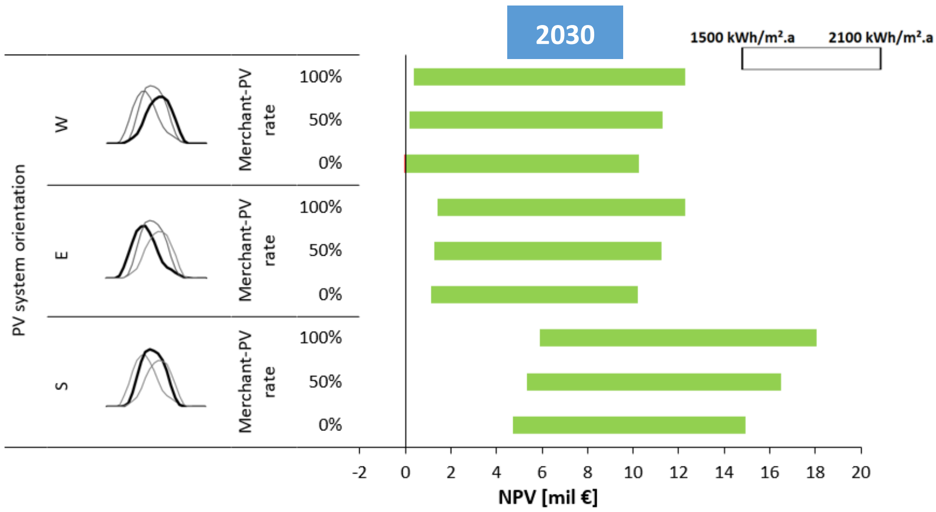
Looking specifically at the impact of different orientations on the NPV results, it appears that the negative impact of the east and west orientations (lower annual production compared to the south-oriented PV system) outweighs the potential positive impact which is to be exposed to the prices earlier in the morning and later in the afternoon which are on average higher.

Looking specifically at the impact of different business models on the NPV results, it appears that under considered assumptions, the merchant-PV business model is more attractive than the fixed-price PPA. It should be noted that these results are most certainly not applicable to currently observed market trends, as in this Task we base the base case on price trends prior to the exceptional and multifactorial (Covid, and invasion in Ukraine) turmoil/volatility. Trends which are currently witnessed on electricity markets will be explored as part of the sensitivity analysis.

- **BaU results for projects starting in different years**

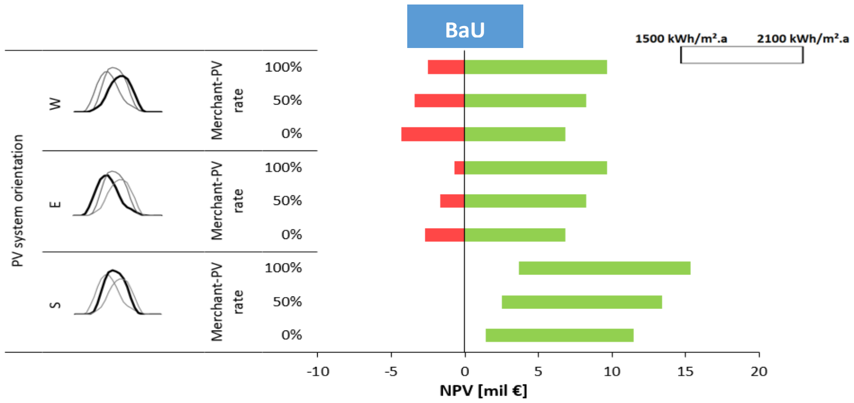


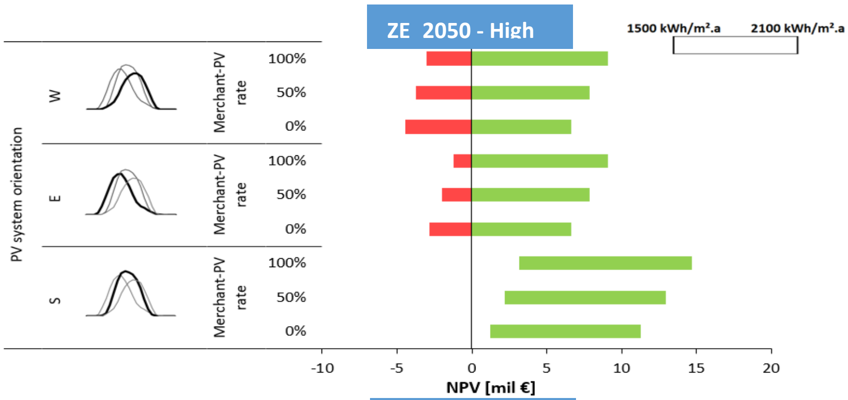


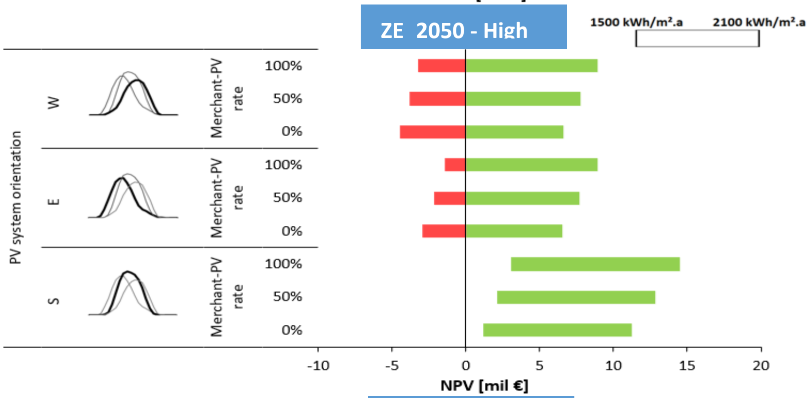


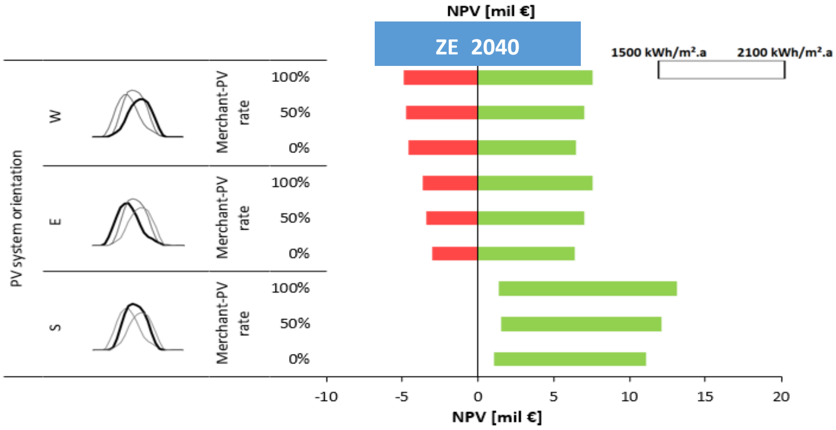
The impact of assumptions taken for decreasing PV system prices is more important than decreasing selling prices under the BaU scenario

- **Results for different scenarios for projects starting in 2025**









The best NPV results in the ZE_2050 High scenario are 50 000 to 150 000 € higher compared to the best NPV results in the ZE_2050 Low scenarios thanks to a reduced number of hours with negative prices.

In the ZE_2040 scenario, the merit order effect is more important, thus making the attractiveness of merchant PV over the 50 €/MWh PPA fixed price less straightforward.

7.4.2 Sensitivity analysis

7.4.2.1 Sensitivity to electricity market prices

Here, coupled sensitivity analysis are conducted. The impact of electricity market prices variations has been already studied through the different scenarios and time horizon. However, here we look more specifically at some possible trends, covering a larger range of possibilities and how they would impact PV profitability. As far as CAPEX variations are concerned, both rising and decreasing CAPEX are studied. Indeed, while the growing PV penetration rates and thus, PV market allow to move forward on the learning curve for its different components and to reach lower costs, as witnessed in the recent months, the single premise that PV components will carry on getting cheaper has been challenged. Under increasing PV penetration rates from PV market rapid growth, the supply-demand balance can be altered leading to rising prices.

- **Rising selling prices and rising CAPEX reflecting currently observed disruptions.**

In the last months, electricity market prices have reached record highs. This trend is a result of a combination and succession of different extraordinary situations: electricity demand surge due to economic activity recovery in all regions of the world as well as the current geopolitical context of war in Ukraine. It can be expected that this conjunctural situation will only impact profitability on the short-term, however it is worth conducting a sensitivity analysis of PV profitability for ground mounted systems to different price increase amplitudes and price increase durations. In addition, the impact of rising selling prices is investigated under different CAPEX increases to reflect the current trends of rising raw materials and logistics costs largely leading together to higher PV system costs.

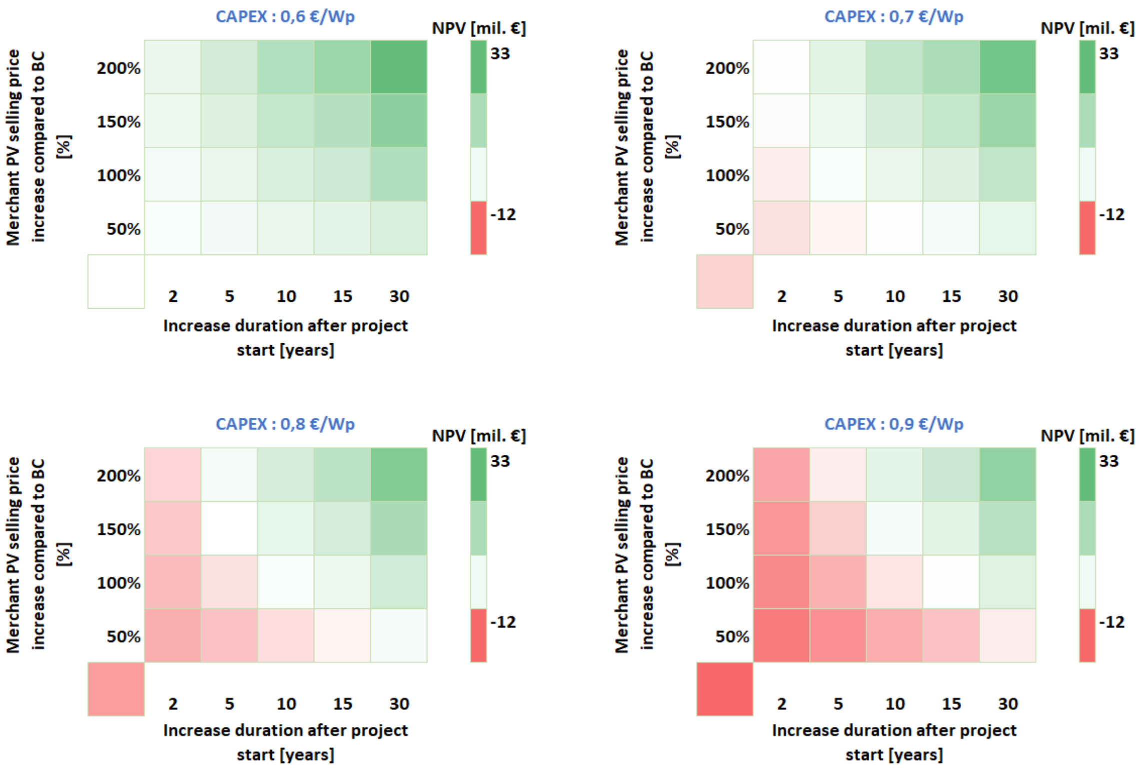


Figure 7-14 - Sensitivity analysis of PV profitability to different selling price increases and increase durations for different CAPEX increases.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with PPA price = 50 €/MWh and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, higher selling prices improve significantly the competitiveness of PV projects. When the CAPEX increases from 0,6 €/Wp to 0,7 €/Wp, the initial NPV can be achieved again with approximately a 200% selling price increase during 2 years or a 100% increase during 5 years under considered conditions.

- **Rising selling prices under different PPA prices.**

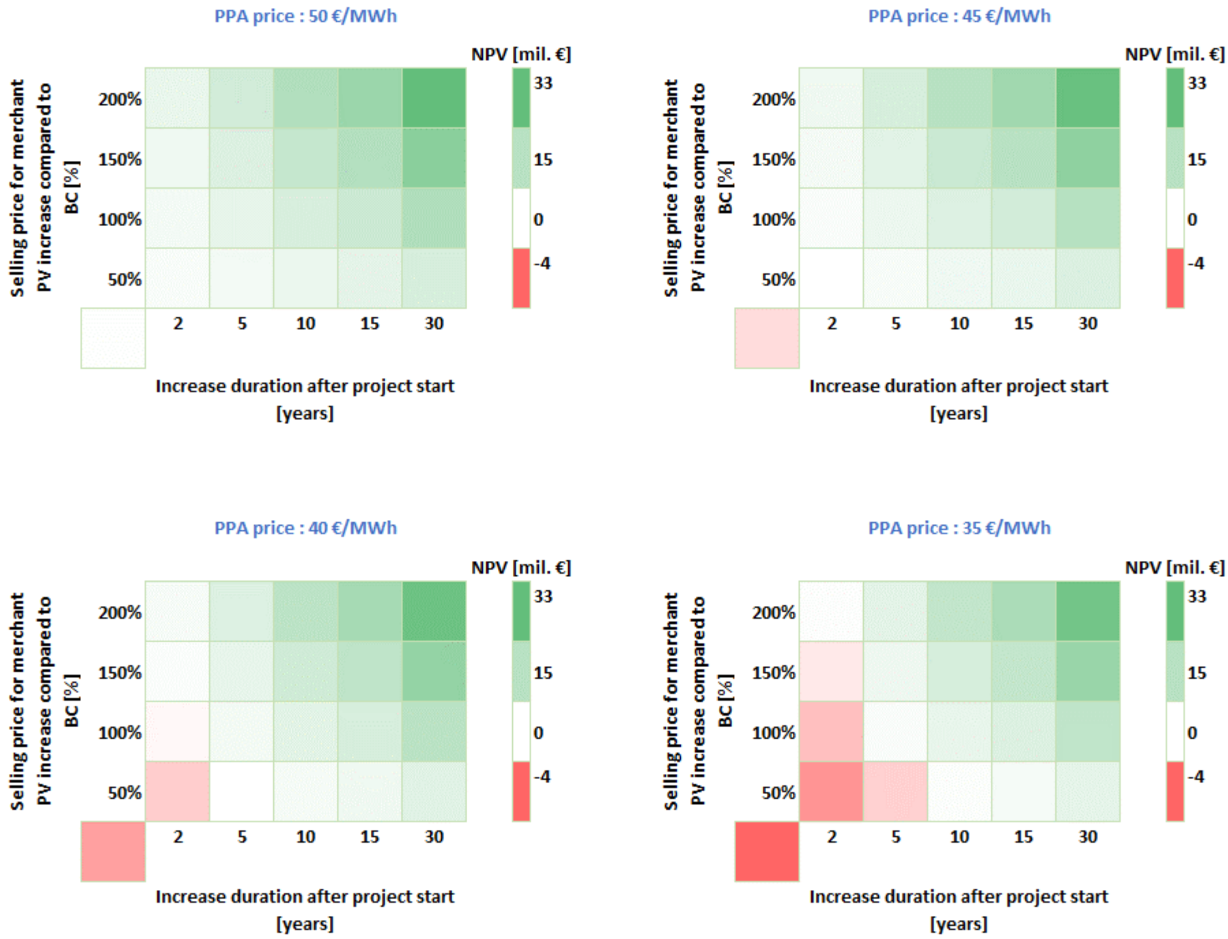


Figure 7-15 - Sensitivity analysis of PV profitability to different selling price increases under different PPA prices.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with CAPEX = 0,6 €/Wp and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, higher selling prices improve significantly the competitiveness of PV projects. When the PPA price decreases from 50 €/MWh to 45 €/MWh, the initial NPV can be achieved again with approximately a 50% selling price increase during 2 years under considered conditions. When the PPA price decreases from 50 €/MWh to 40 €/MWh, the initial NPV can be achieved again with approximately a 50% selling price increase during 5 years or 150% selling price increase during 2 years under considered conditions.

- <u>**Decreasing selling prices reflecting cannibalisation effect and decreasing CAPEX**</u>

Here, a sensitivity analysis of PV profitability for ground mounted systems to different price decrease amplitudes and price decrease durations is conducted. In addition, the impact of decreasing selling prices is investigated under different CAPEX decreases to reflect the learning curve effect which can still be expected for different PV system components in the aftermath of current supply chain turmoil and price hikes.

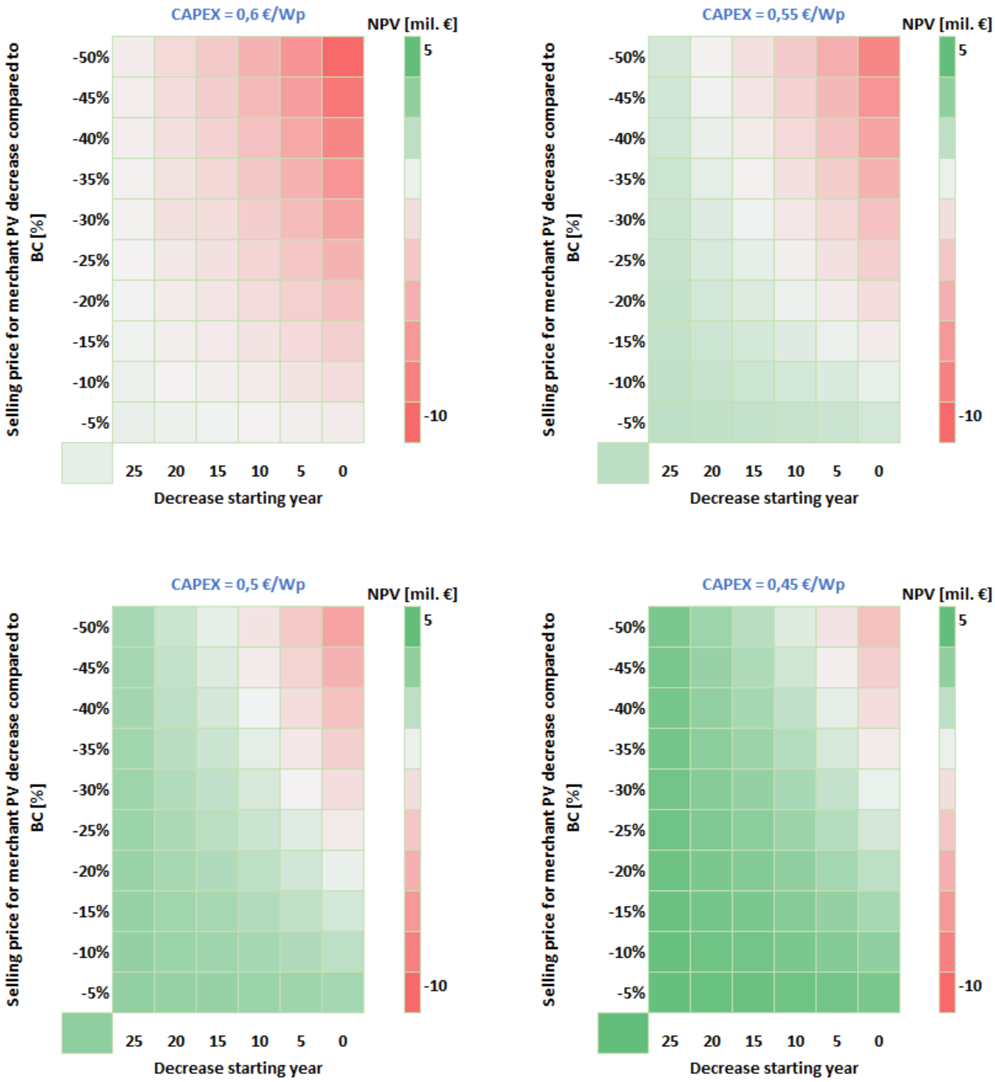


Figure 7-16 - Sensitivity analysis of PV profitability to different selling price decrease under different CAPEX.

Notes: Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 50% PPA / 50% merchant PV business model with PPA = 50 €/MWh and under the BaU, high adaptation scenario for a project starting in 2022.

As observed in the heatmap on the top left, lower selling prices deteriorate significantly the competitiveness of PV projects, all the more so as selling price start declining soon after project start.

When the CAPEX decreases from 0,6 €/Wp to 0,55 €/Wp, the initial NPV can be achieved again even with approximately a -10% selling price decrease starting 7 years after project start or a -15% selling price decrease starting 12 years after project start under considered conditions.

- **Occurrence of negative prices**

In previously presented results, negative prices are included in the modelling and differ based on the time-horizon (and associated PV penetration rate) and the scenario.

However, these negative prices are only modelled in terms of European average, yet important differences exist from one country to another, even currently, in terms of the occurrence of negative prices as illustrated in Figure 7-17.[30] Thus, this sensitivity analysis aims at covering a broader range of situations.

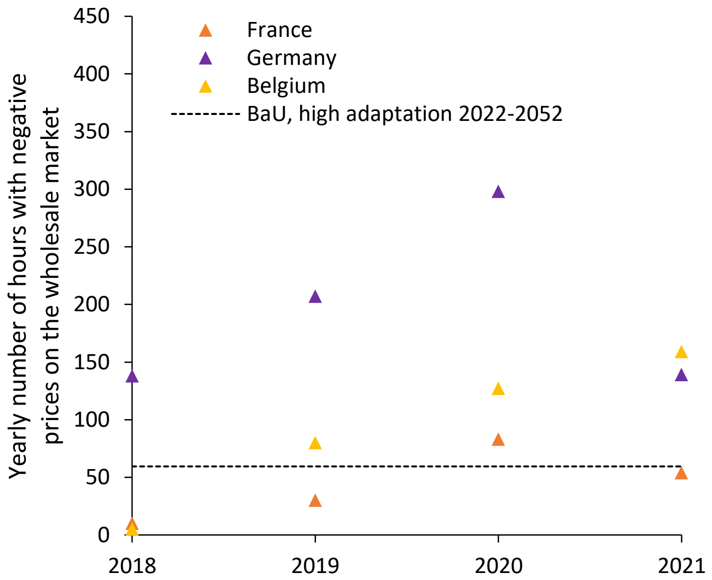


Figure 7-17 - Yearly number of hours with negative prices on the wholesale market in different EU countries and in the BaU 2022-2052, high adaptation simulated prices.

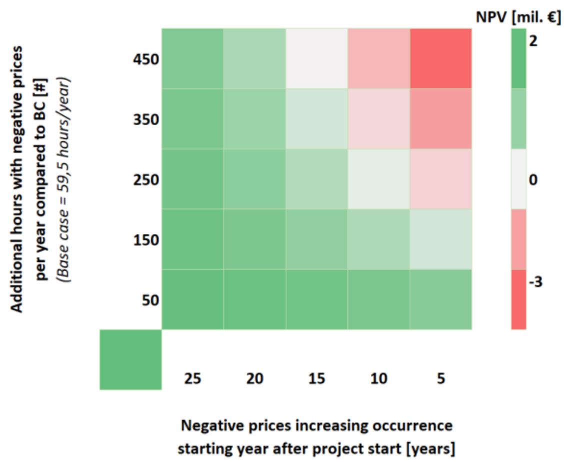


Figure 7-18 - Sensitivity analysis of PV profitability to different negative prices hours occurrence increase.

Notes:

- *Sensitivity analysis is conducted for an average yearly irradiation of 1500 kWh/m².a, a south-oriented ground-mounted system, under a 100% merchant PV business model and under the BaU, high adaptation scenario for a project starting in 2022.*
- *Additional hours with negative prices refer to hours across the 8760 hours of the year. Thus, additional assumption is made on the share of these negative price hours that take place during PV production hours. For N hours with negative prices per year, it is assumed that 30%*N full load hours equivalent of PV are taking place during negative prices episodes. Negative price is assumed to be -25€/MWh on average and full load hours are assumed to amount to 1000 hours.*

For the considered case, the higher occurrence of negative prices starts to jeopardize PV profitability starting with 450 additional hours of negative prices per year after 15 years of project, or 250 additional hours of negative prices per year after 10 years. Overall, most additional negative hours under considered assumptions take place during the night or during hours when PV production is non-existent or low. Therefore, the overall impact on PV profitability is low.

8 REFERENCES

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9 APPENDIXES

9.1 Impact of higher PV penetration rates on grid financing

No appendixes for this section.

9.2 Impact of higher PV penetration rates on distributed PV profitability

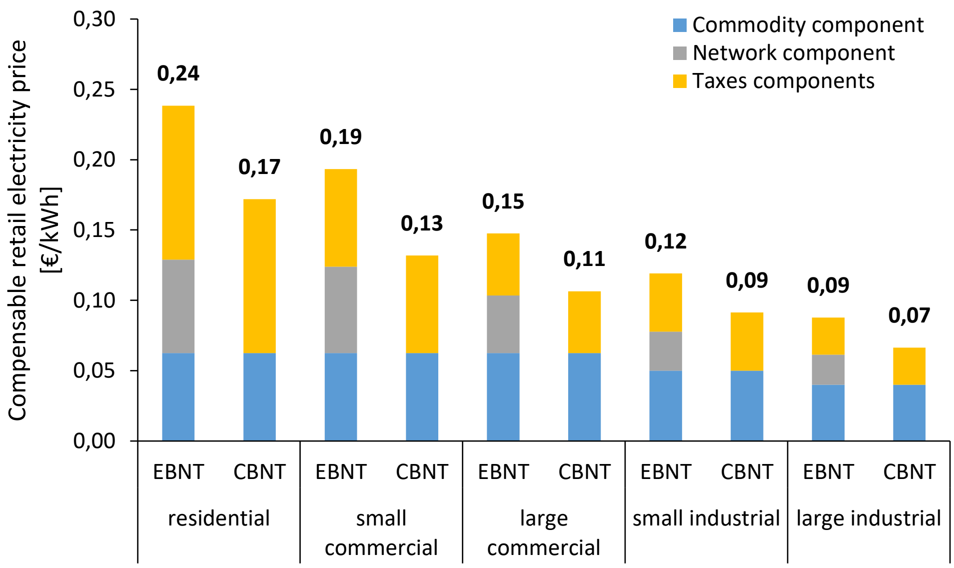
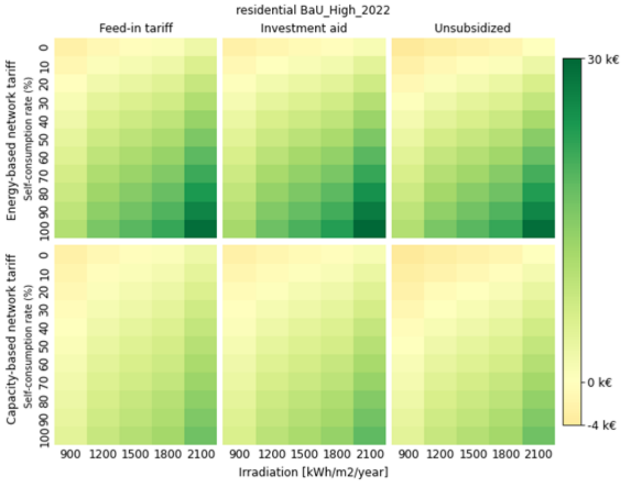


Figure 9-1 - Considered compensable retail electricity prices per type of consumers (Elaboration by Becquerel Institute based on collected electricity prices structures in partner countries) *(EBNT: energy-based network tariff, CBNT: capacity-based network tariff)*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Investment aid
Unsubsidized
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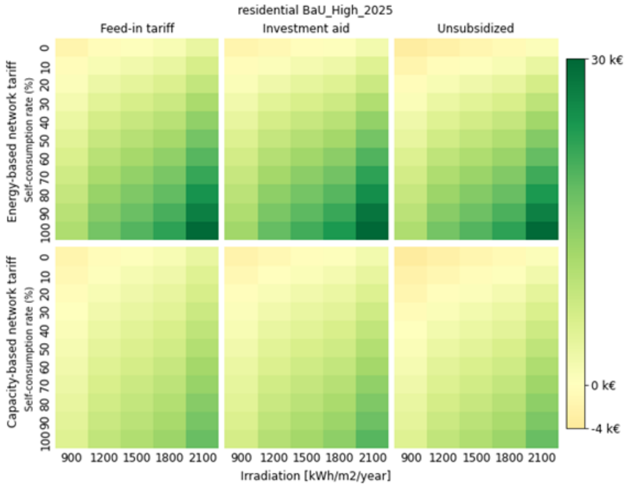
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
30 k€
0 k€
-4 k€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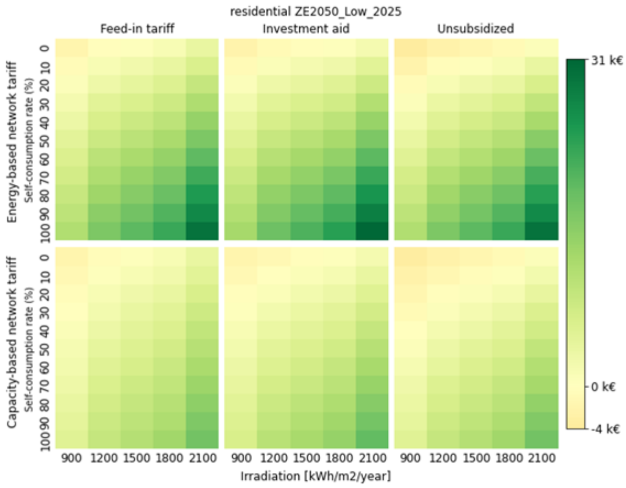
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
30 k€
0 k€
-4 k€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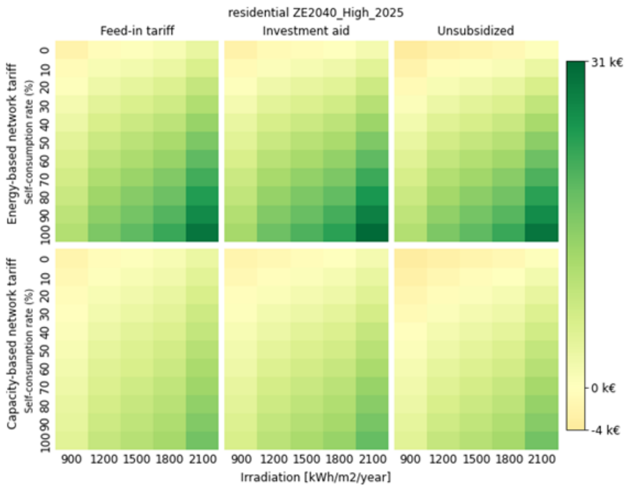
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
31 k€
0 k€
-4 k€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Investment aid
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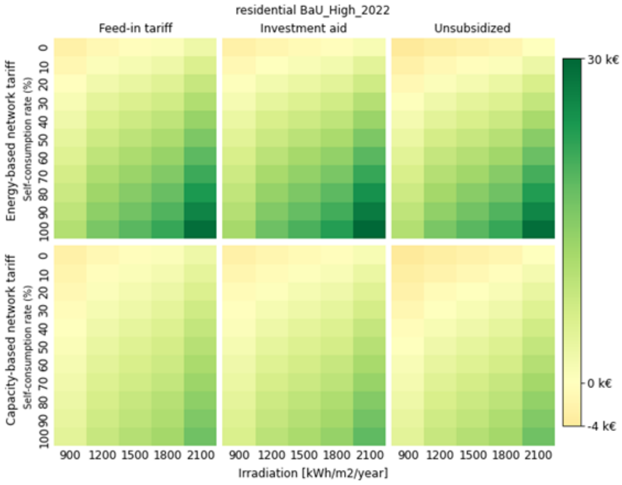
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
31 k€
0 k€
-4 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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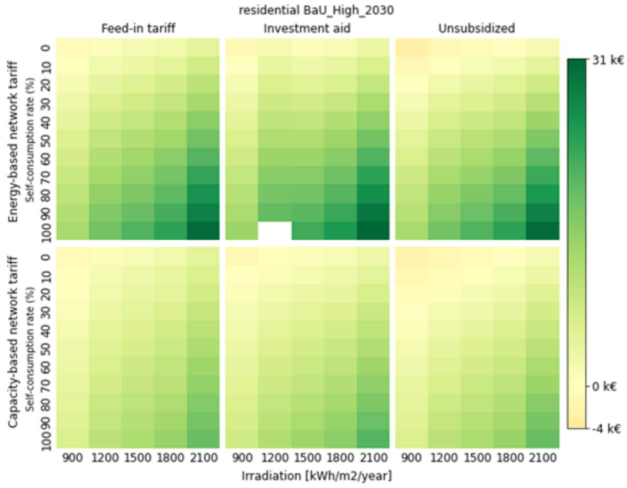
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
30 k€
0 k€
-4 k€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Capacity-based network tariff
Self-consumption rate (%)
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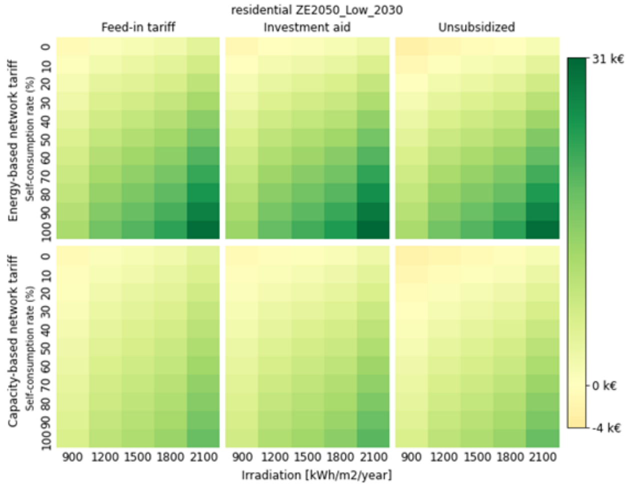
Irradiation [kWh/m2/year]
31 k€
0 k€
-4 k€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Investment aid
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Capacity-based network tariff
Self-consumption rate (%)
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900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
31 k€
0 k€
-4 k€


residential ZE2040_High_2030
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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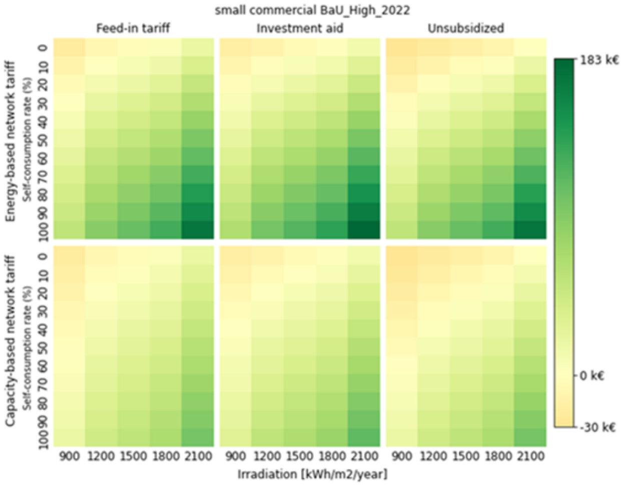
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
31 k€
0 k€
-4 k€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Capacity-based network tariff
Self-consumption rate (%)
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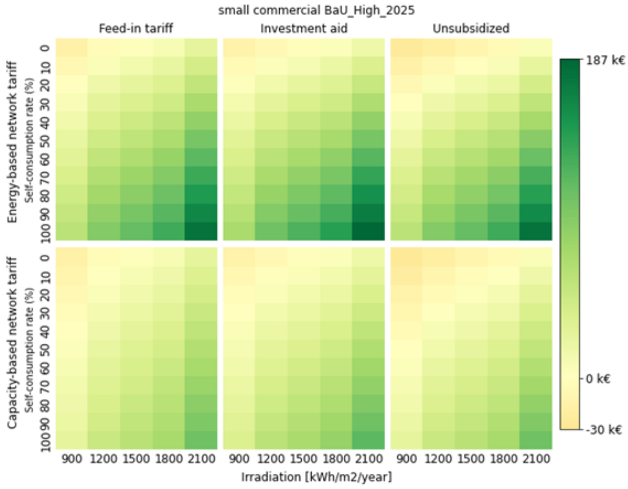
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
183 k€
0 k€
-30 k€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Irradiation [kWh/m2/year]
187 k€
0 k€
-30 k€


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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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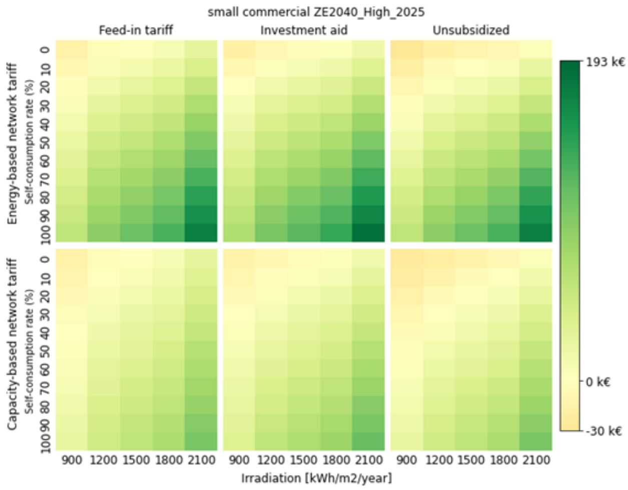
Irradiation [kWh/m2/year]
193 k€
0 k€
-30 k€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Capacity-based network tariff
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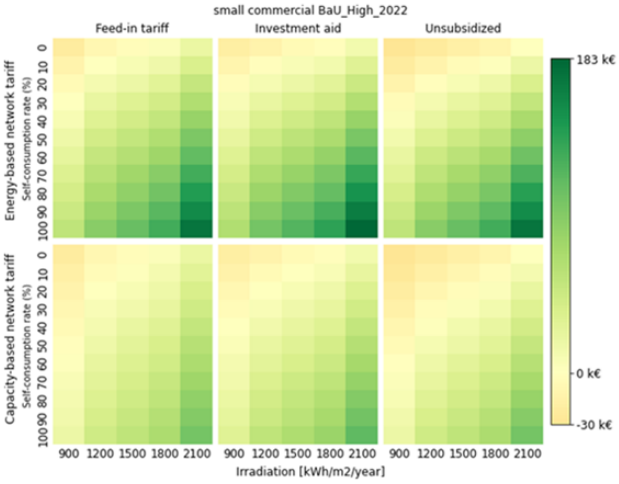
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
193 k€
0 k€
-30 k€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Investment aid
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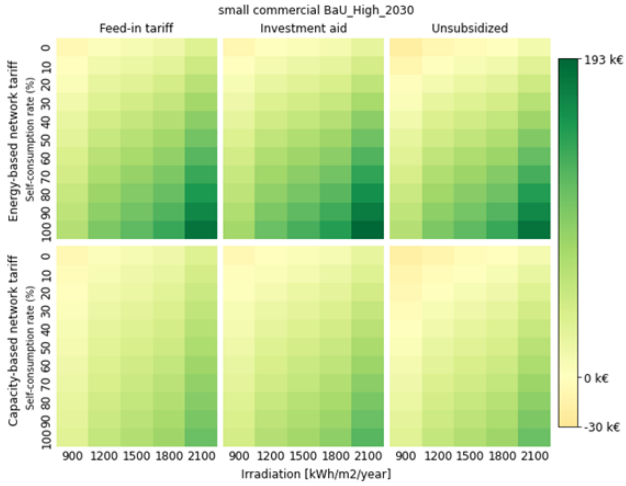
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
183 k€
0 k€
-30 k€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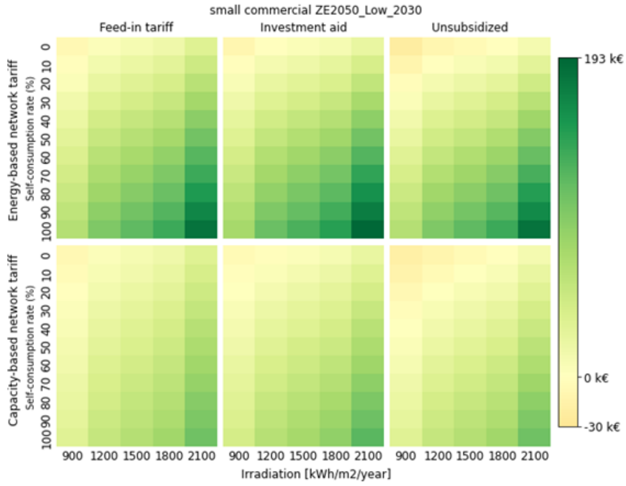
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
193 k€
0 k€
-30 k€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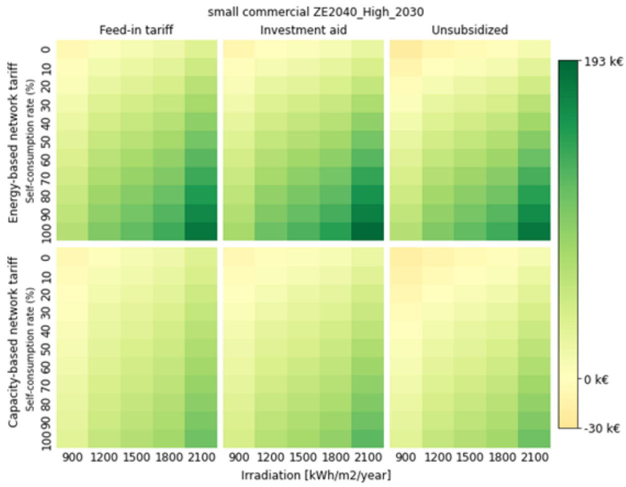
Self-consumption rate (%)
Irradiation [kWh/m2/year]
193 k€
0 k€
-30 k€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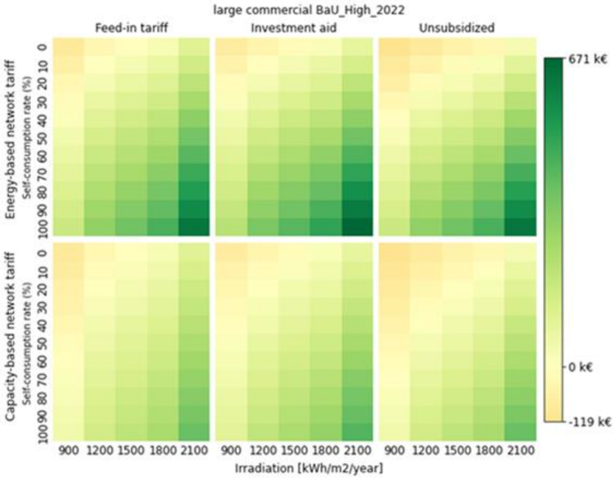
Capacity-based network tariff
Self-consumption rate (%)
Irradiation [kWh/m2/year]
193 k€
0 k€
-30 k€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Capacity-based network tariff
Self-consumption rate (%)
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Irradiation [kWh/m2/year]
671 k€
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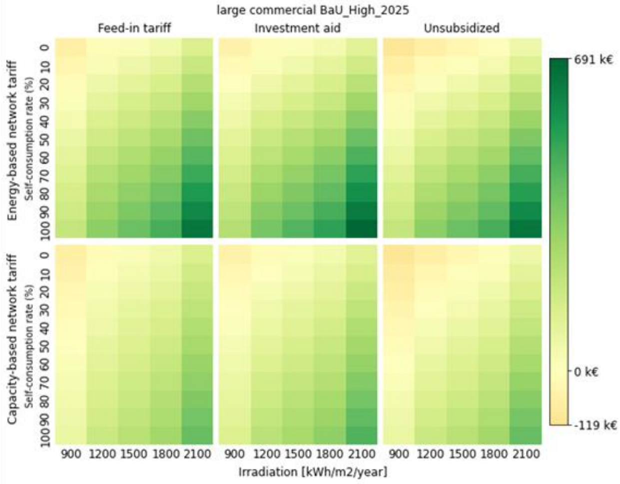
-119 k€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Capacity-based network tariff
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Irradiation [kWh/m2/year]
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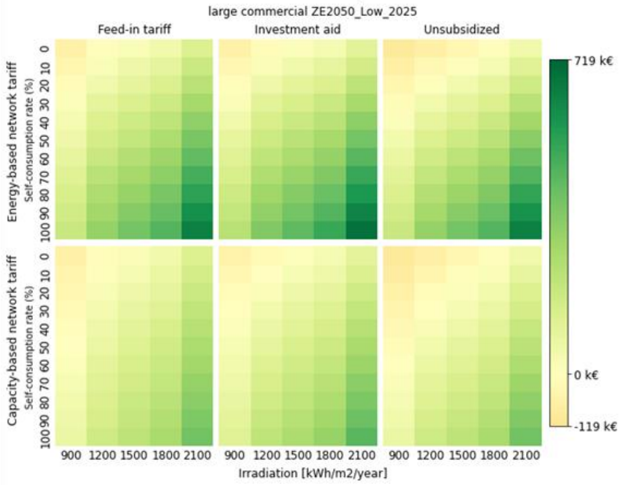
-119 k€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Irradiation [kWh/m2/year]
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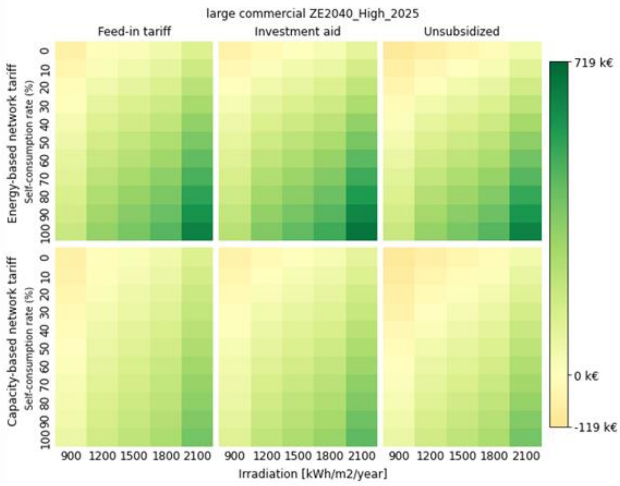
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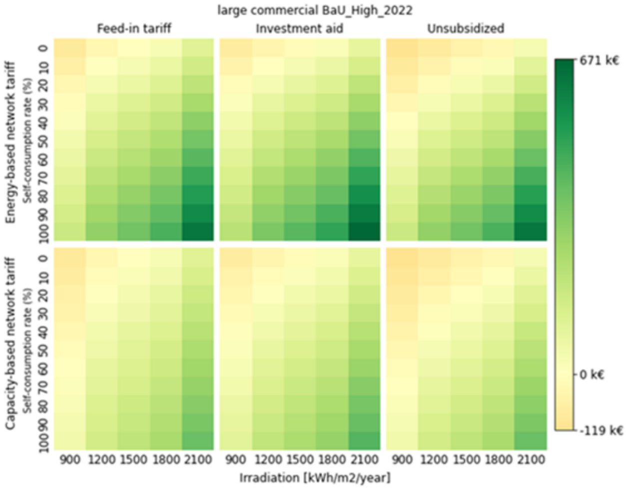
719 k€
0 k€
-119 k€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Capacity-based network tariff
Self-consumption rate (%)
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671 k€
0 k€
-119 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]


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Feed-in tariff
Investment aid
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Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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0 k€
-119 k€
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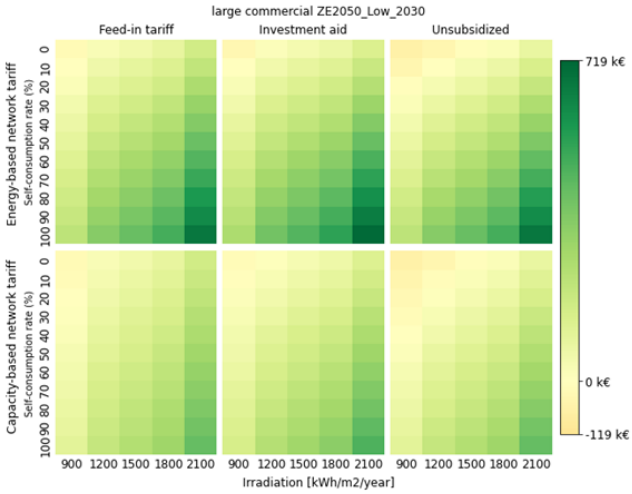
Irradiation [kWh/m2/year]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0 k€
-119 k€
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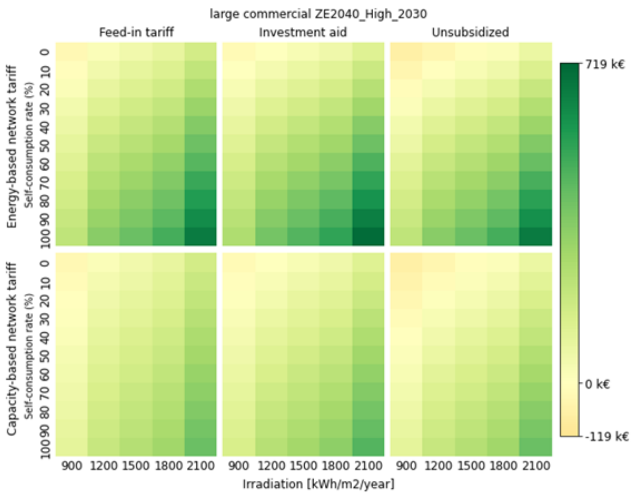
Irradiation [kWh/m2/year]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Investment aid
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Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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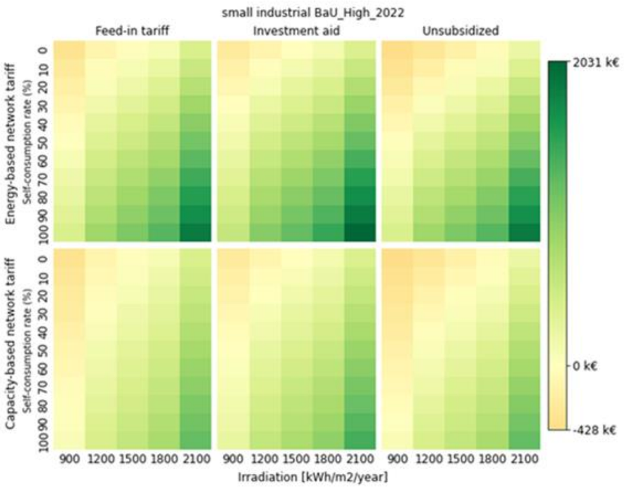
719 k€
0 k€
-119 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]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Capacity-based network tariff
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Irradiation [kWh/m2/year]
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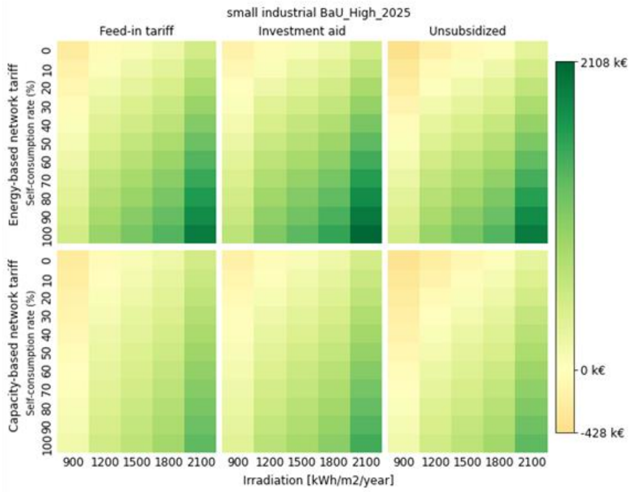
0 k€
-428 k€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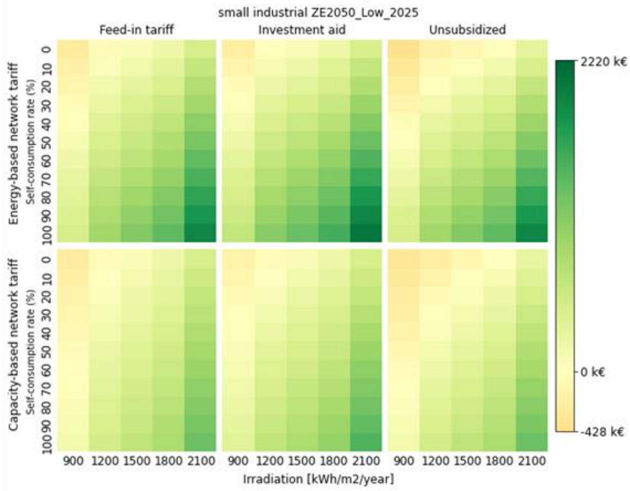
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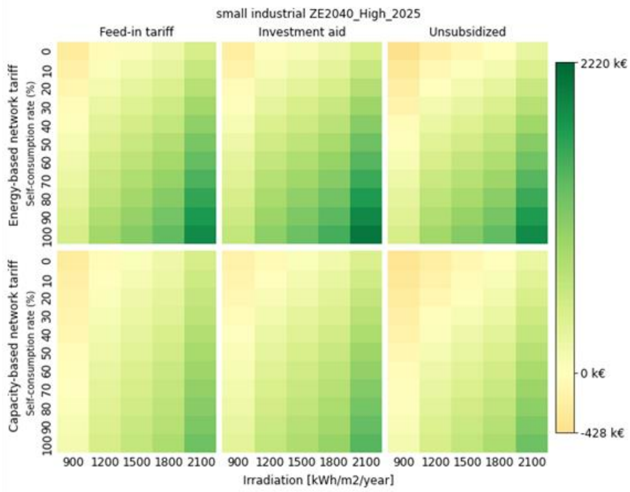
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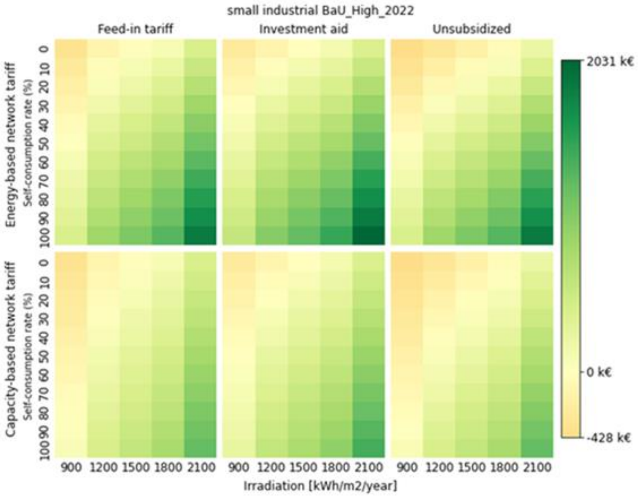
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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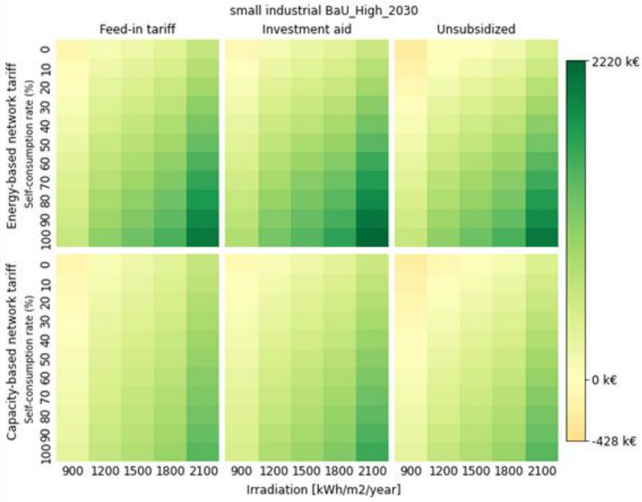
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2031 k€
0 k€
-428 k€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Capacity-based network tariff
Self-consumption rate (%)
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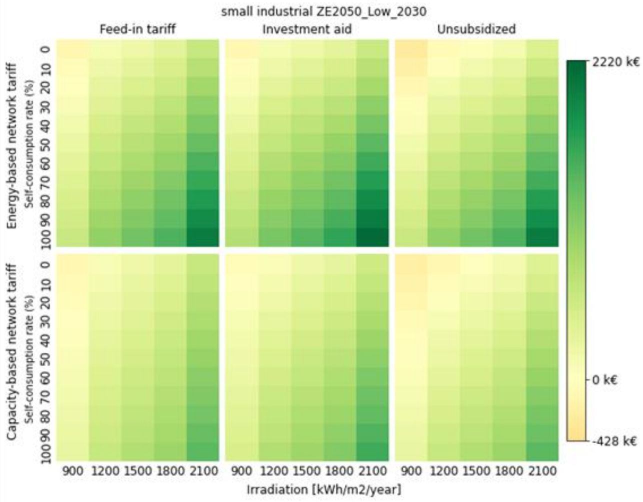
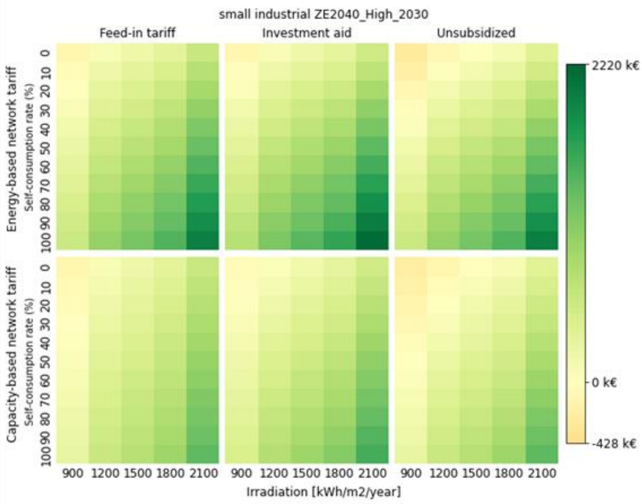
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€


small industrial ZE2050_Low_2030
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
0 10 20 30 40 50 60 70 80 90 100
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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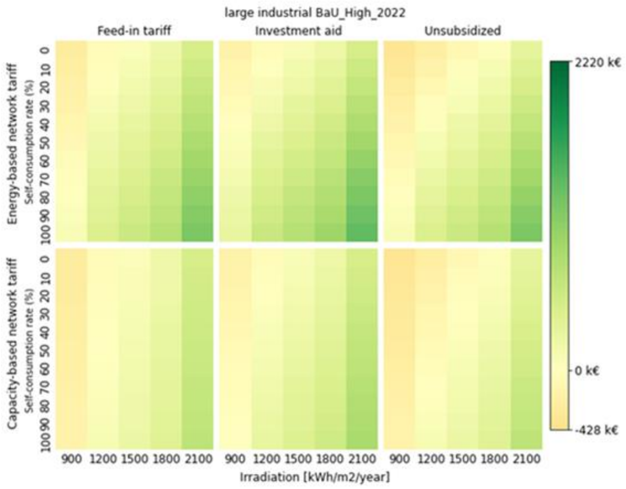
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€


large industrial BaU_High_2022
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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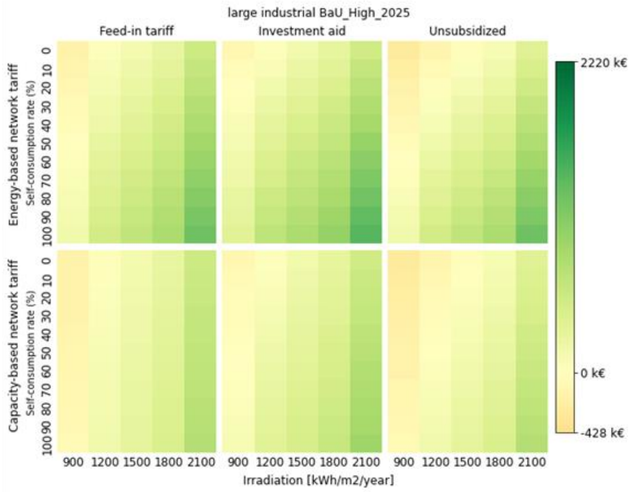
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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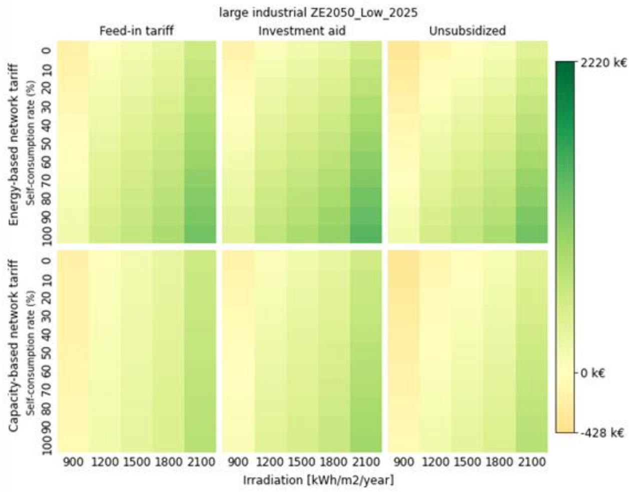
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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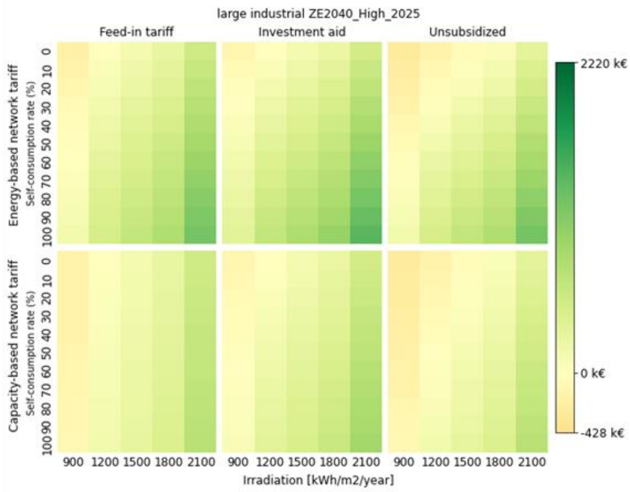
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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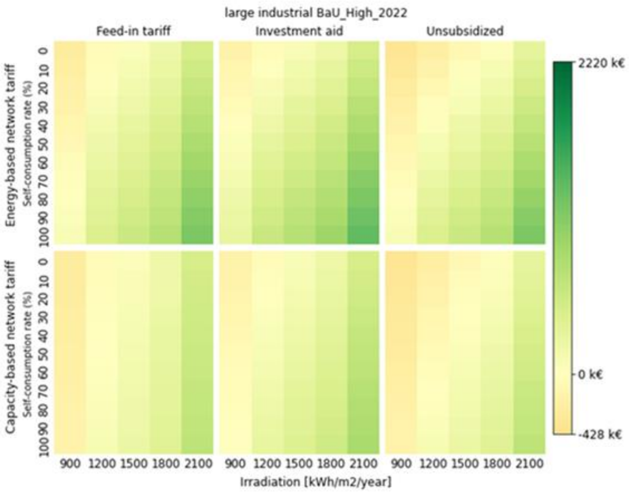
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]
2220 k€
0 k€
-428 k€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Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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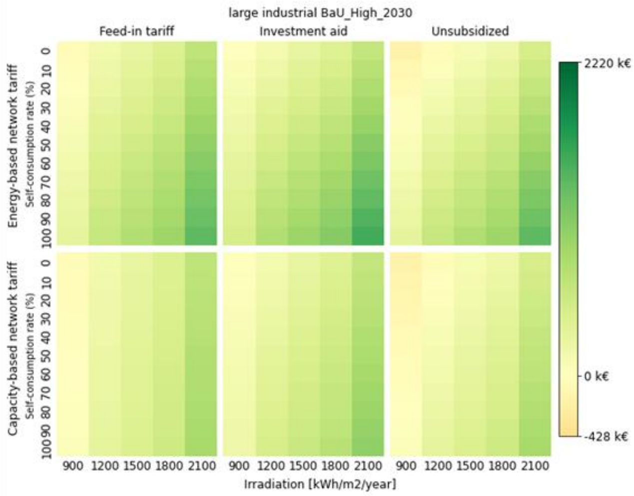
2220 k€
0 k€
-428 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]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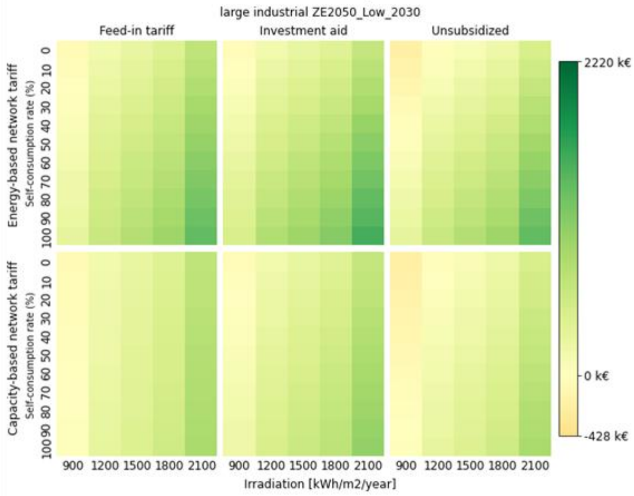
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
0 10 20 30 40 50 60 70 80 90 100
2220 k€
0 k€
-428 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]


large industrial ZE2050_Low_2030
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
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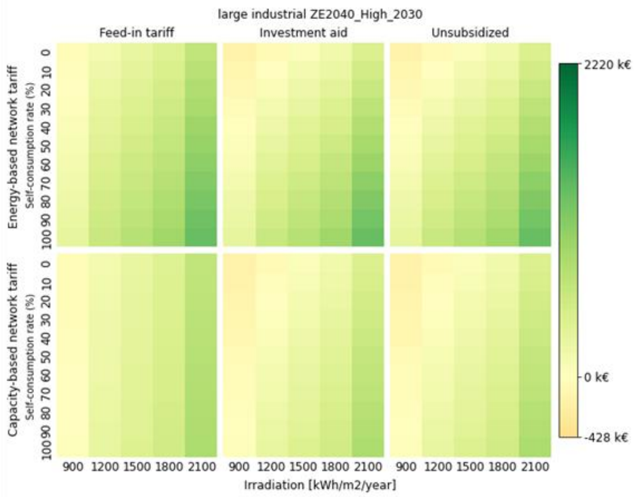
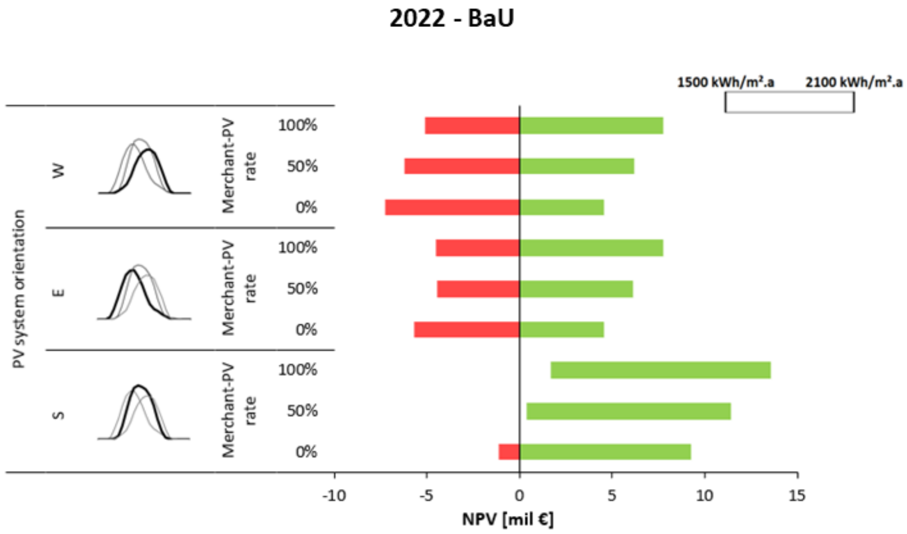
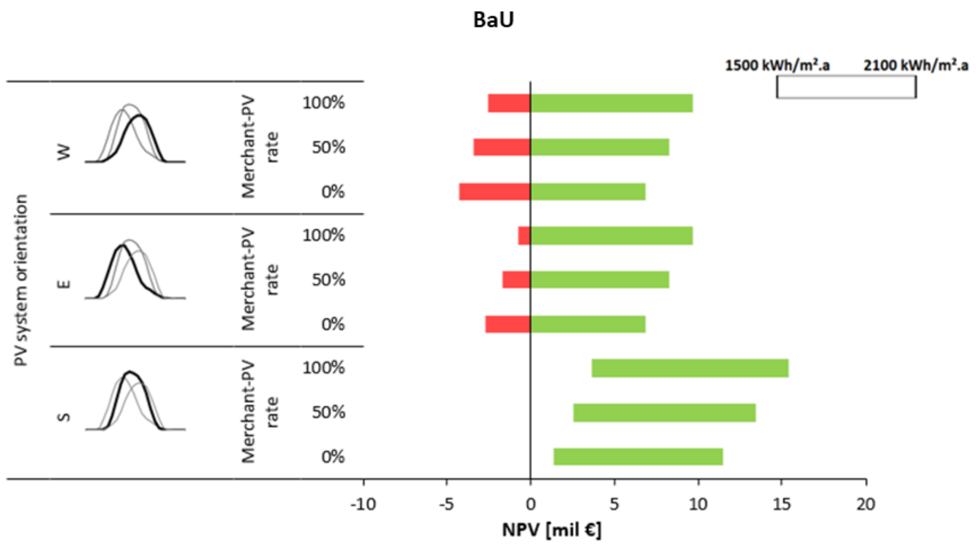
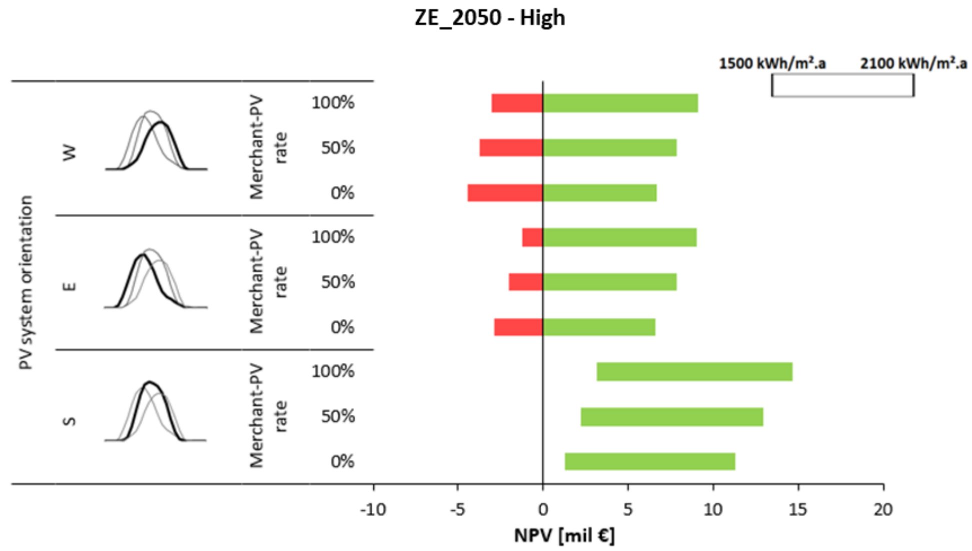
2220 k€
0 k€
-428 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]


large industrial ZE2040_High_2030
Feed-in tariff
Investment aid
Unsubsidized
Energy-based network tariff
Capacity-based network tariff
Self-consumption rate (%)
0 10 20 30 40 50 60 70 80 90 100
2220 k€
0 k€
-428 k€
900 1200 1500 1800 2100
Irradiation [kWh/m2/year]

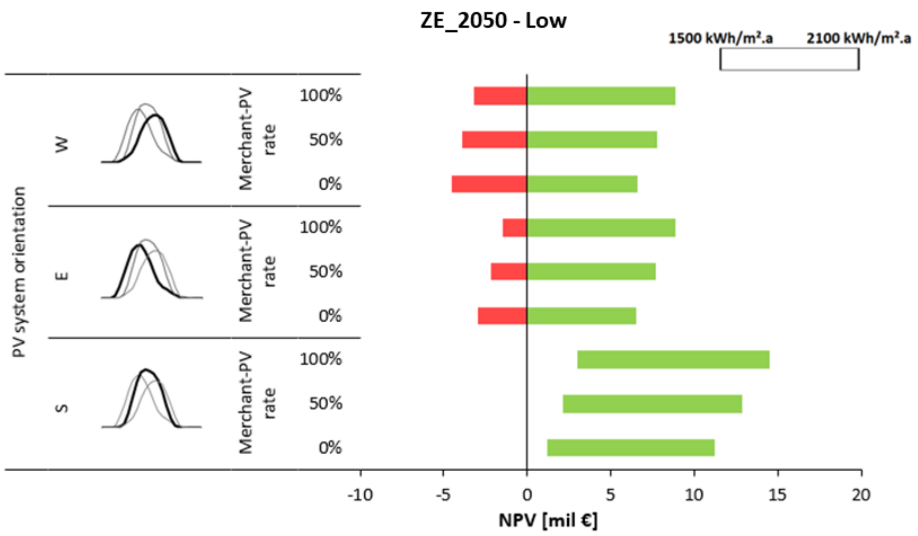
9.3 Impact of higher PV penetration rates on centralised PV profitability

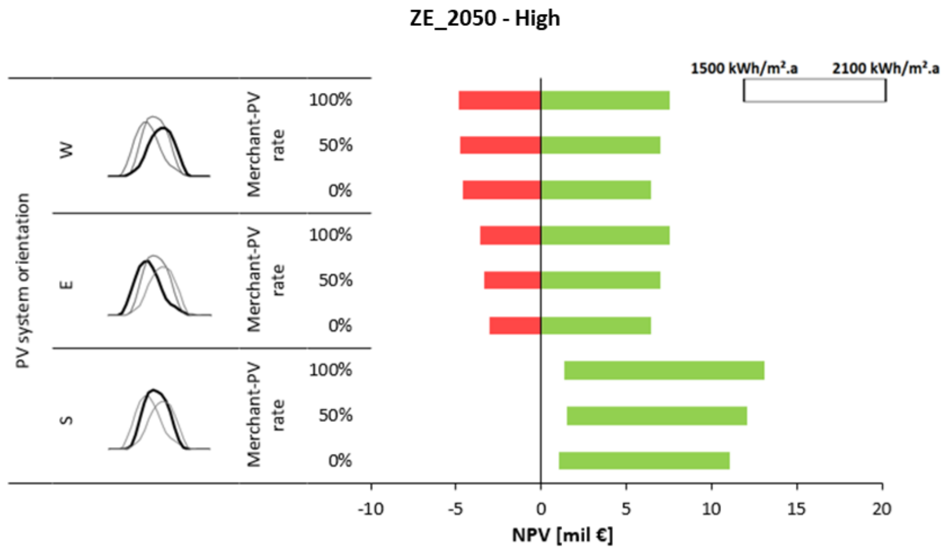


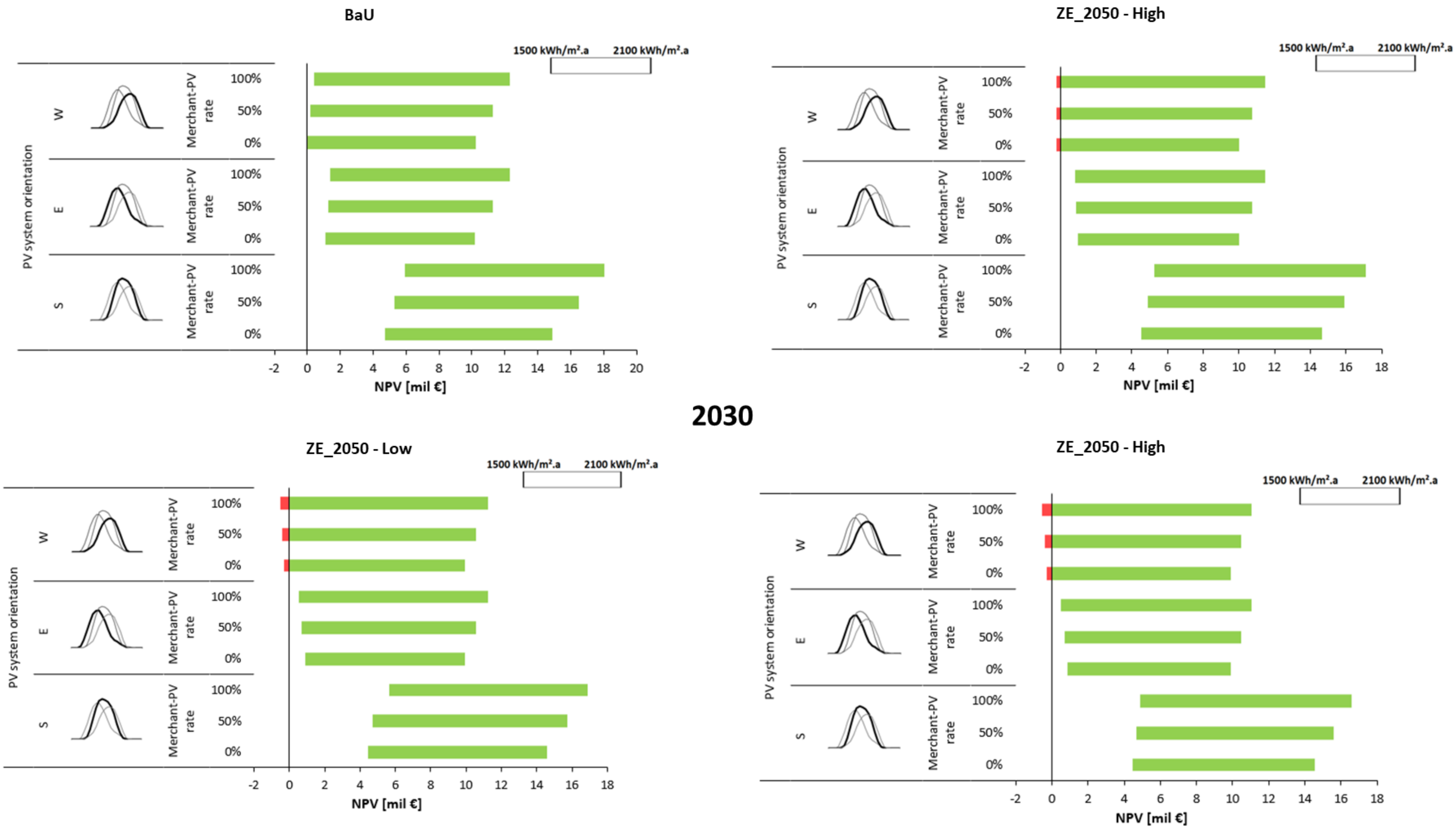

BaU
1500 kWh/m².a
2100 kWh/m².a
PV system orientation
W
E
S
Merchant-PV rate
100%
50%
0%
-10
-5
0
5
10
15
20
NPV [mil €]


ZE_2050 - High
1500 kWh/m².a
2100 kWh/m².a
PV system orientation
W
E
S
Merchant-PV rate
100%
50%
0%
-10
-5
0
5
10
15
20
NPV [mil €]

2025


ZE_2050 - Low
1500 kWh/m².a
2100 kWh/m².a
PV system orientation
W
E
S
Merchant-PV rate
100%
50%
0%
-10
-5
0
5
10
15
20
NPV [mil €]


ZE_2050 - High
1500 kWh/m².a
2100 kWh/m².a
PV system orientation
W
E
S
Merchant-PV rate
100%
50%
0%
-10
-5
0
5
10
15
20
NPV [mil €]


BaU
ZE_2050 - High
2030
ZE_2050 - Low
ZE_2050 - High
1500 kWh/m².a
2100 kWh/m².a
PV system orientation
W
E
S
Merchant-PV rate
100%
50%
0%
NPV [mil €]