Axpo Energy Reports

Solar energy

Introduction

A secure, affordable and sustainable electricity supply is fundamental to the functioning of Swiss society and the economy. Today, Switzerland benefits from very good conditions for a reliable supply thanks to hydropower, nuclear power, new renewable energies and its central location in the European power grid.

In the coming decades, this comfortable situation will come under pressure if no suitable countermeasures are put in place. The electrification of mobility and heating, and population growth are likely to increase electricity demand significantly. In addition, data centres, cloud services and generative AI require increasing energy. At the same time, the planned phase-out of nuclear power means that a substantial part of domestic electricity production will be lost in the long term.

The winter half-year in particular are becoming more and more important. Switzerland already consumes more electricity in winter than it produces. In the darker months of the year, there is more demand for heat and people generally spend longer indoors, which increases the power consumption of electronic devices and lighting. In addition, hydropower produces more electricity in the summer half-year due to the seasonal runoff profile with a high proportion of run-of-river water. The current expansion of renewable energies in Switzerland and neighbouring countries is also based to a large extent on solar energy, which produces mainly in the summer half-year. The seasonal difference between the summer surplus and the winter deficit is increasing, making it increasingly difficult to secure winter supplies.

In addition to close cooperation with neighbouring countries and the EU, securing the supply of electricity in the future also requires secure, affordable and sustainable domestic electricity production to be developed. As part of Axpo Energy Reports, we look at four technologies that can substantially increase domestic electricity generation in winter: wind energy, new nuclear power plants, solar energy and gas-fired power plants.

The report specifically shows which regulatory and social framework conditions are needed to expand solar energy. The report is not to be understood as a position paper and does not assess whether solar energy should be expanded. It merely describes the conditions that must be met in order for solar energy to make a substantial contribution to winter electricity generation by 2050.

This report deals with the expansion of solar energy in Switzerland by 2050.

Disclaimer: This report was originally drafted in German and has been carefully reviewed by experts, particularly with regard to terminology and content accuracy. The translations are intended to make the report more accessible to a nationwide and international audience and have been produced with the utmost care. In the event of any questions regarding interpretation, the original German version is considered authoritative.

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List of abbreviations

ARE	Federal Office for Spatial Development
SFOE	Swiss Federal Office of Energy
ESTI	Federal Inspectorate for Heavy Current Installations
ElecA	Federal Act on Weak and Heavy Current Electrical Installations SR 734.0
REO	Ordinance on the Promotion of Electricity Production from Renewable Energy Sources SR 730.03
EnA	Energy Act SR 730.0
PV	Photovoltaics
kWp	Kilowatt peak
LEG	Local electricity community
SPA	Federal Act on Spatial Planning SR 700
TRL	Technology readiness level
ZEV	Private consumption community

01

Summary

Photovoltaics have been extensively expanded in Switzerland for a number of years. At the end of 2025, around 9.7 GW of installed PV capacity was in operation, which covered around 14 percent of national electricity consumption in 2025. The installation takes place almost exclusively on rooftops and façades. Ground-mounted, agricultural and alpine PV plants have played only a minor role so far. PV production is strongly seasonal. Around three quarters of annual electricity generation occurs in the summer half-year with around only 25 to 30 percent occurring in the winter half-year.

The SFOE estimates that the long-term usable photovoltaic potential in Switzerland is around 100 TWh per year and therefore significantly exceeds the 2050 expansion targets set by the Energy Act (45 TWh). The majority of this potential is on rooftops and facades (around 75 TWh), while the rest is distributed between agricultural PV (14 TWh), alpine PV (6 TWh) and infrastructure PV (4 TWh). Alpine and facade PV plants and, depending on their orientation and location, other types of plant typically have a higher proportion of winter generation. As with the SFOE, we do not identify any potential for ground-mounted PV because it is not clear how the relevant areas should be defined. This depends heavily, for example, on the extent to which agricultural land is included. However, the potential for ground-mounted PV is very high.

The strong expansion of decentralised PV plants is posing new challenges for distribution grids as they have historically been designed for a one-sided flow of electricity and a strong increase in local production can lead to grid bottlenecks. Potential solutions for integration include feed-in limits, flexibility measures that benefit the grid (e.g. battery storage and controllable demand) and targeted grid expansion, whereby feed-in limits often cause only minimal losses in production. From 2026, new regulatory framework conditions with dynamic and locally differentiated grid tariffs will enable flexibility that benefits the grid to be activated in a more targeted manner. Analyses carried out with ETH Zurich show that demand-driven grid expansion alone incurs costs of CHF 40–50 million per year and that these costs can rise to as much as CHF 230 million annually in the event of significant PV expansion and limited flexibility.

Social acceptance varies greatly depending on the investment type. Photovoltaics on rooftops, facades and existing infrastructure enjoys a very high level of approval in Switzerland and has the highest acceptance values of all electricity generation technologies. This is also reflected in the strong expansion of these power plants in recent years.

The legal framework conditions for PV also vary greatly depending on the type of plant. rooftops and façade plants are generally subject only to notification as they already comply with zoning regulations and have no significant impact on the environment or land use. This enables rapid and largely conflict-free implementation. On the other hand, ground-mounted, agricultural and alpine PVs are subject to more complex spatial planning requirements and complex approval procedures. These represent a major hurdle for expansion. The Acceleration Decree, which was passed by the Swiss Parliament during the autumn session of 2025 and will come into force in stages from April 2026[1], provides for the consolidation of the current authorisation process for larger PV plants of national interest into a cantonal planning approval procedure. This simplification and simultaneous limitation of the number of possibilities for appeals should shorten the duration of approval. However, from a structural planning perspective, the basic prerequisite is the definition of suitable areas, i.e. areas that the cantons proactively designate for the construction of large-scale PV plants. At the end of 2025, the cantons had not yet identified any suitable areas. In the meantime, however, initial technical principles have been drawn up to assist the cantons in examining and defining suitable areas. In particular, areas with little or no conservation value – as identified in studies by the ARE, among others – can serve

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[1] DETEC, 2026, Secure electricity supply

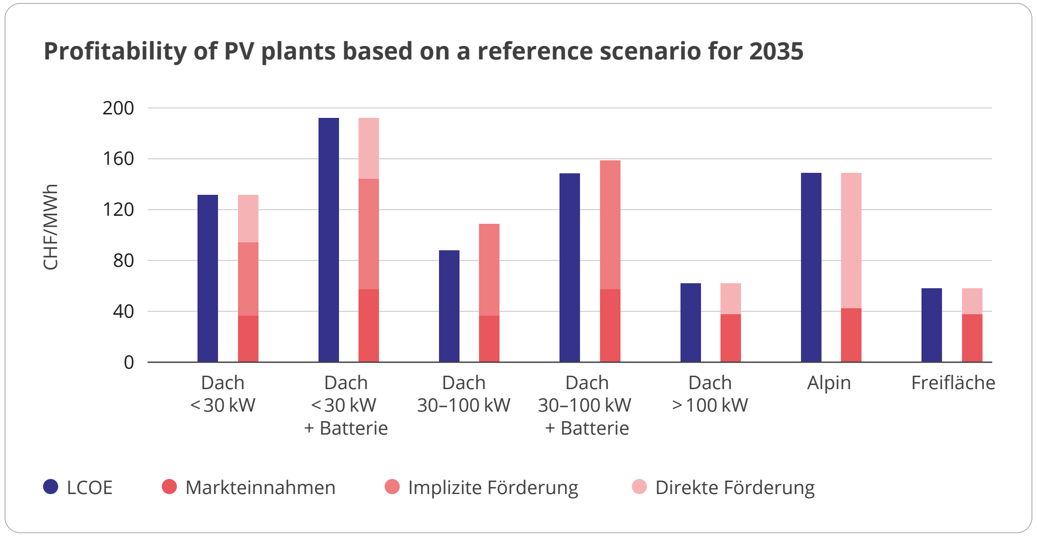

Figure 1: Profitability of PV plants in 2035 less fair value and implicit subsidy for own use.

as an important starting point in this regard. In order to enable the expansion of ground-mounted PV, it is now essential that the cantons comprehensively examine these spaces and identify suitable areas. In addition, communes can also go ahead in their use planning and provide special zones for smaller plants, e.g. on pre-contaminated areas. These are often easier to implement, economically attractive and well accepted.

Like any other generation technology, both rooftop and ground-mounted PV cannot be operated economically without financial support. Financial support for solar power in Switzerland is now comprehensive and represents a key driver for its further expansion. Various subsidy schemes are available depending on the size and type of the plant, as well as the potential for own use. Investment grants, which cover part of the investments, are available for both small- and large-scale plants. Larger plants can also choose between an investment grant and a sliding-scale market premium. At present, however, the investment grant is the most commonly used option. Investments without own use can receive subsidies of up to 60 percent of the investments, while investments with own use receive lower subsidies of up to 30 percent. PV plants of less than 150 kW also benefit from a statutory minimum remuneration for the feed-in. In addition, there are various specific bonuses, such as a tilt angle bonus for steep installations, a parking bonus for covered parking spaces and a winter electricity bonus for installations with particularly high winter production. The winter electricity bonus is intended to specifically promote installations that make an above-average contribution to electricity production during the winter half-year. Both alpine facilities and facilities in the Swiss Mittelland region with a suitable orientation can benefit from this (provided they are not covered by the 'Solarexpress' scheme, i.e. Article 71a of the Energy Act). In addition to this direct subsidy, PV plants with own use are also implicitly subsidised as they do not have to pay grid fees for electricity they use themselves and can therefore reduce their contribution to grid costs. The resulting shortfall must be borne by the other end customers via higher grid charges. This results in a redistribution of grid costs that does not reflect the principle of 'the polluter pays'.

Taking into account current financial support, many PV plants are economical, but the differences between the types of plants are significant (see Figure 1). The levelised cost of electricity for PV plants consist of modules, assembly, planning, inverters, substructure, cabling and transport. The modules themselves now account for only a small proportion of the costs, whereas installation and the supporting structures in particular can make up a large part of the costs. The costs vary considerably depending on the plant type and location. Economies of scale play a key role.

Small-scale rooftop plants benefit only to a limited extent from economies of scale and lower module costs as the proportion of fixed costs for planning, installation and management is comparatively high. As a result, their levelised cost of electricity is significantly higher than that of other types of plant and is, as a rule, two to three times higher than that of ground-mounted plants. On the one hand, large rooftop plants are increasingly able to achieve economies of scale. As the size of the plant increases, the specific costs fall, so their levelised cost of electricity gradually approaches that of ground-mounted plants. Ground-mounted plants generally have the lowest levelised cost of electricity. On the other hand, alpine PV plants have the highest levelised cost of electricity.

Implicit subsidies in the form of reduced grid cost contributions is crucial to the economic viability of rooftop PV as it covers 45–83 percent of the generation costs depending on the type of plant. Without this support, many smaller plants would not be profitable. Over the next 30 years, market revenues from rooftop and ground-mounted PV will cover an average of around 39 CHF/MWh, i.e. 30–65 percent of production costs, while alpine PV can cover only around 26 percent of costs on the market despite slightly higher revenues of around 42 CHF/MWh.

If a plant is expanded to include a battery storage system, this increases revenue through higher own use and more timely marketing. However, due to production costs that are 50–80 percent higher, this does not always result in improved cost-effectiveness.

Accordingly, the demand for subsidies varies greatly between the plant types. The subsidy for rooftop PV consists of direct and implicit subsidies. For 2035, there will be a funding requirement of around 95 CHF/MWh for rooftop PV below 30 kW and around 20 CHF/MWh for ground-mounted PV, while larger rooftop plant have no additional funding requirements. At around 107 CHF/MWh, alpine PV remains by far the most dependent on subsidies.

Rooftop PV plants in Switzerland account for a high proportion of domestic value creation in the total costs. Over the entire life cycle, around 84 percent of the total costs remain in Switzerland as planning, financing, construction, installation and operation take place predominantly in Switzerland, while only around 16 percent of the expenses – mainly for modules and inverters – go abroad. Value creation varies over time as a large proportion is generated during the construction phase, followed by a smaller but long-term contribution to domestic value creation during operation, meaning that 75 percent of the total costs over the entire lifespan are channelled into domestic value creation. Investments in rooftop PV plants also make a substantial contribution to employment, creating around 650 full-time jobs per terawatt-hour generated over the plant's lifetime. The integration of battery storage changes this picture in that the proportion of costs incurred abroad rises due to higher manufacturing costs, while at the same time the absolute domestic value creation of the overall system continues to increase.

Both rooftop PV and ground-mounted PV produce very low greenhouse gas emissions and negligible amounts of radioactive waste. The relevant environmental impacts of rooftop PV arise predominantly indirectly in the upstream stages of the life cycle. Ground-mounted PV requires a large amount of domestic land and generates a comparatively high volume of hazardous waste from manufacturing processes due to the high demand for copper in transformation, cabling and substructures.

02

Technology

Rooftop solar PV is undergoing significant expansion in Switzerland, yet contributes only marginally to domestic electricity generation during the winter months. While roofs offer considerable potential, other surfaces present opportunities as well. Grid integration remains a challenge as rooftop PV capacity grows substantially.

In brief

- As of 2025, PV plants with a total capacity of around 9.7 GW are installed in Switzerland. Electricity produced from PV covered around 14 percent of Switzerland's electricity consumption in 2025. Almost 99 percent of plants are installed on rooftops. Other plant types, such as ground-mounted PV or alpine PV, remain rare.
- The usable potential of solar energy in Switzerland is substantial; the SFOE estimates the potential on rooftops to be 55 TWh per year by 2050, and as much as 99 TWh including other areas. Experience with ground-mounted installations in Switzerland remains limited, meaning their full potential is not yet known.
- PV production is highly seasonal: only about 25 percent of the solar power is generated in the winter half-year. However, thanks to their location and orientation, alpine PV, façade PV and plants above the fog line in general can reach a winter electricity share of up to 50 percent.
- The decentralised expansion of PV production poses challenges in terms of grid integration. Grid expansion and flexibility measures can reduce the impact. Depending on this and the future PV expansion, annual expansion costs could increase significantly. In scenarios with high PV expansion and only moderate use of these measures, the annual costs for distribution grid expansion rise to up to CHF 180 million.

2.1
Technological development

Photovoltaics (PV) refers to the direct conversion of solar energy into electricity. In recent decades, extensive subsidies, technological innovations, optimised manufacturing processes and economies of scale have transformed what was once a niche technology into a globally expanded form of energy generation. The cost of PV modules has fallen over the past 50 years from over CHF 100 000 per kW to well below CHF 1000 per kW. Another reason for the fall in costs was the increase in efficiency, depending on the technology used.[2, 3, 4] Today, monocrystalline PV cells dominate the global market, with an efficiency of between 20 percent and 25 percent[5, 6]. This means that standard modules such as those used in Switzerland have an output of around 200 W/m². However, these figures are already close to the physically possible efficiency limit for a single cell, which is around 33 percent[7]. Having said this, performance improvements beyond this are possible through further developments such as tandem cells or concentration of radiation.

This cost reduction, combined with increased efficiency, was driven by a global push to expand PV. In 2024, PV plants accounted for 7 percent (2100 TWh) of global electricity generation, and this figure is set to rise.[6]

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[2] IRENA, 2023, Renewable power generation costs in 2023

[3] Nemet, 2009, Interim monitoring of cost dynamics for publicly supported energy technologies

[4] NREL Photovoltaic Research, 2025, Best Research-Cell Efficiency

[5] IEA, 2025, Global Energy Review

[6] IEA International Energy Agency, 2024, Trends in Photovoltaic Applications

[7] Shockley-Queisser limit of the maximum achievable efficiency without concentration of irradiation or stratification of the cells.

2.2
Current buildout

At the end of 2025, installed PV capacity in Switzerland was around 9.7 GW. This generated slightly more than 8 TWh of electricity in the year, which was around 14 percent of national electricity consumption[8].

The expansion of photovoltaics received a strong boost from 2009 with the introduction of cost-covering feed-in remuneration (KEV), which guaranteed a long-term fixed remuneration for fed-in solar power. As a result, the expansion increased rapidly at first, but came to a standstill due to capped funding and years of waiting lists. In order to secure the financing of the subsidy, the grid surcharge was gradually increased in subsequent years and now stands at 2.3 centimes/kWh. In addition, the federal government introduced the one-off remuneration (EIV) in 2014, which was a one-off investment grant that gradually replaced the KEV and made it easier to access support.

There was a significant growth spurt from 2020 onwards, due in part to falling costs and improved framework conditions. A new record was set in 2024 with an expansion of around 1.8 GW[9]. The expansion was carried out almost entirely on the rooftops of existing and new buildings. By 2025, approximately 99 percent of the plants will be installed on the rooftops of industrial and commercial buildings, as well as on residential and agricultural buildings, or on building facades. Ground-mounted, agricultural and alpine PV together make up only a small part of the portfolio[10, 11].

However, electricity production from PV plants in Switzerland is highly seasonal (see Figure 4). The largest share comes from the sunny summer half-year, which accounts for around 75 percent of production. The share of electricity generated during the winter

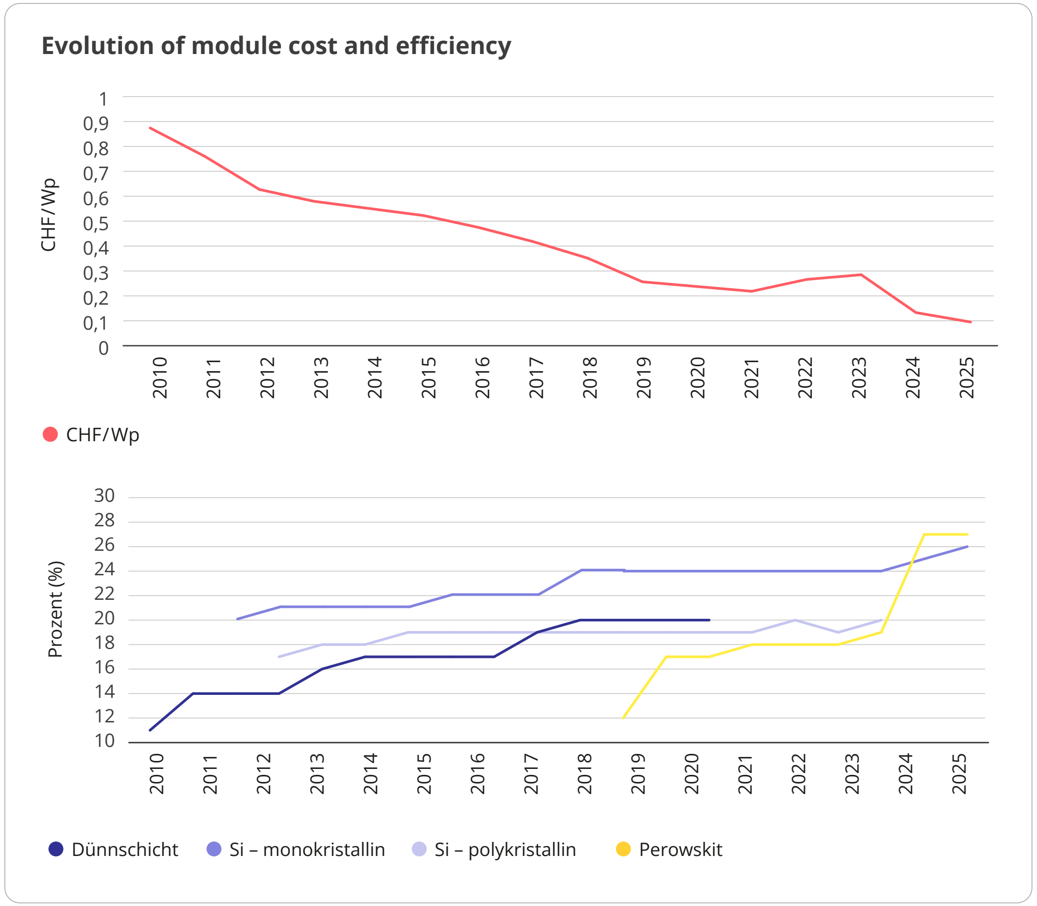
Evolution of module cost and efficiency

Figure 2: Historical progression of the costs of commercially available PV modules[12] in CHF (2025) per watt (top) and maximum efficiencies[13] in percent (bottom).

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[8] Swiss Federal Office of Energy SFOE, 2025, Electricity statistics
[9] Swissolar, 2025, Solarmonitor
[10] Swiss Federal Office of Energy, 2025, Electricity statistics
[11] Swissolar, 2025, Solarmonitor
[12] pvXchange, 2025
[13] NREL Photovoltaic Research, 2025, Best Research-Cell Efficiency

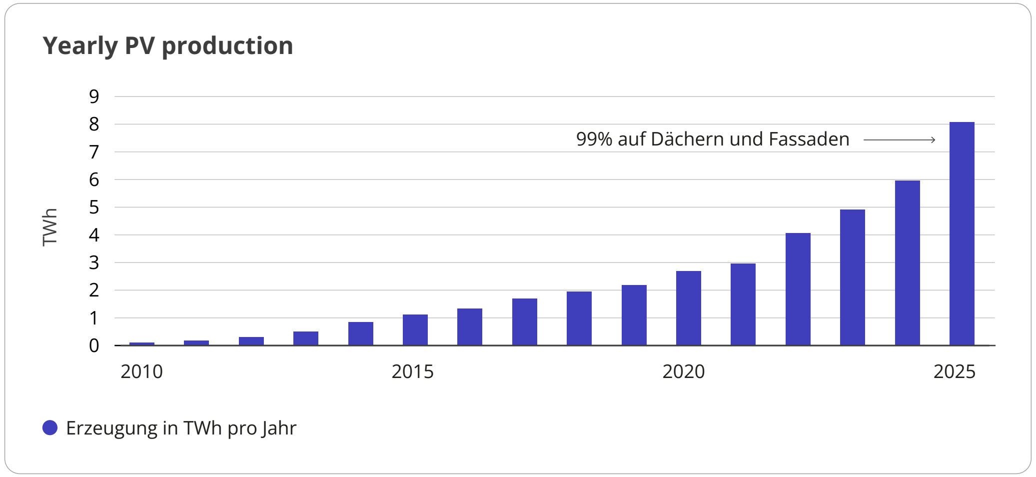

Figure 3: Annual electricity production from photovoltaic plants in Switzerland. In 2025, around 99 percent of production comes from plants on the rooftops of industrial and commercial buildings as well as residential and agricultural buildings, or on façades.

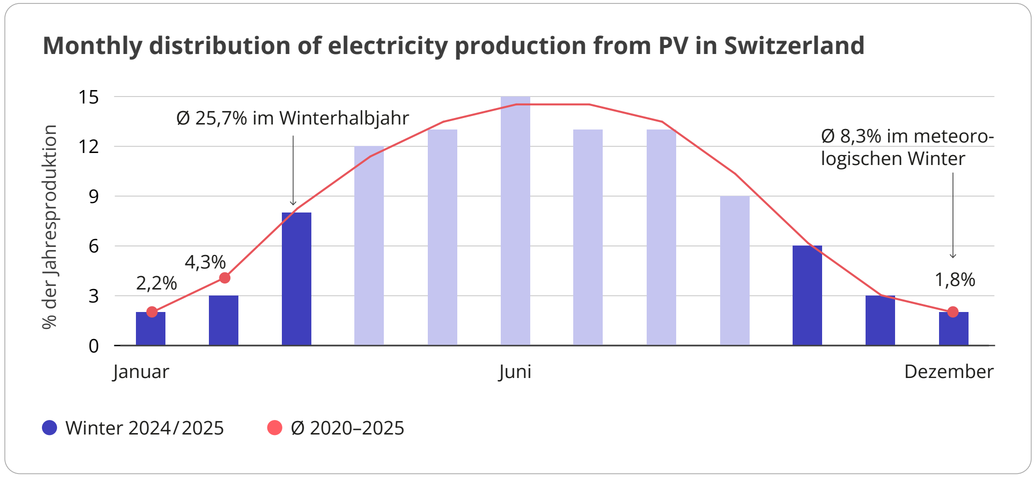

Figure 4: Monthly distribution of electricity production from PV in Switzerland as a percentage of the annual production volume of PV. On average, around 25.7 percent of production falls in the winter half-year between October and March.

half-year has averaged 25.7 percent in recent years[14]. In the winter half-year of 2024/25, Swiss PV plants generated 1.8 TWh, thereby covering around 6 percent of electricity demand during this period. However, approximately half of this was generated in October and March, whilst in December, for example, the figure was only 5 percent.

The construction of PV plants in the alpine region is seen as an important option for increasing the share of winter electricity. At higher altitudes, solar power plants benefit from increased irradiance due to snow reflection, less fog and higher module efficiency due to lower temperatures. Overall, this means significantly more winter electricity is available. The Solarexpress scheme launched in 2022 enabled the federal government to support the expansion of such alpine PV plants up to a total annual electricity generation cap of 2 TWh. For plants with a high proportion of winter electricity, planning and approval procedures outside the building zone were simplified and a one-off remuneration of up to 60 percent of the investment was introduced. For a project to benefit from the subsidy, the planning application had to be made available for public consultation by the end of 2025. Despite varying levels of implementation efficiency across the cantons and ongoing debates regarding landscape and nature conservation, several large-scale pro-

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[14] Swiss Federal Office of Energy SFOE, 2025, Electricity statistics

jects were initiated, such as Grengiols-Solar in Valais. By the end of 2025, however, only four plants with a planned annual output of around 0.07 TWh were in partial operation, while 25 plants had been approved or were subject to public consultation. If all approved and publicly consulted plants were to be built, this would amount to approximately 0.66 TWh per year[15]. The expansion target of 2 TWh originally envisaged by the Solarexpress will therefore be clearly missed, even if all current projects are fully realised. The main reason for this is the very high construction and development costs in alpine terrain, which leads to insufficient economic viability despite high subsidies and increased winter electricity production.

Plants in subalpine locations could represent a more cost-effective alternative to alpine PV for increasing the share of winter electricity generated by PV. They would benefit from some of the advantages of alpine PV plants, such as significantly fewer foggy days than in lowland areas, while challenges such as snow loads and access are likely to be easier to resolve than at alpine sites. This could lead to significantly lower construction costs.

2.3

Usable potential

The Swiss Federal Office of Energy (SFOE) estimates the long-term usable potential of PV in Switzerland at around 100 TWh per year.[16] The potential determined clearly exceeds the EnA target of 45 TWh of renewable electricity generation by 2050.[17] The theoretical long-term potential defined by the SFOE relates mainly to rooftop and façade installations (74 TWh) and, to a lesser extent, to agricultural PV (14 TWh), alpine PV (6 TWh) and infrastructure PV (4 TWh).

The usable potential on rooftops is typically divided into different size classes: plants of < 30 kW (29 TWh), 30–100 kW (13 TWh) and > 100 kW (12 TWh). As large rooftop areas for plants of > 100 kW are already heavily developed, available space in this segment is becoming increasingly scarce. This phenomenon is well known in practice and follows an economic logic because larger plants are cheaper than smaller ones, so they offer the highest returns and, therefore, better profitability (see Section 5). Consequently, these areas were prioritised for development. As a result, the remaining development potential is increasingly shifting towards small and medium-sized roof areas, which, while less cost-effective, are available in significantly greater numbers.

For agricultural PV, the definition used by the Federal Office for Spatial Development (ARE) is applied here, which covers only PV plants that lead to an improvement in agricultural productivity[18]. Although it has not yet been conclusively established on which agricultural land a guaranteed increase in productivity can be achieved, this is most likely to apply to permanent crops. Accordingly, the potential identified by the Swiss Federal Office of Energy (SFOE) relates exclusively to permanent crop areas. Initial trials, for example with berries, fruit and vines, show that targeted shading can stabilise or increase production, although this depends heavily on the crop, location and plant design.[19]

Both we and the SFOE do not identify any potential for ground-mounted PV. An assessment of the potential depends in particular on the extent to which agricultural land should be included. In July 2025, the ARE published a methodological framework designed to help the cantons identify suitable areas for ground-mounted PV[20]. This marks the federal

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[15] Swiss Federal Office of Energy SFOE, 2026, Alpine solar power plants

[16] Swiss Federal Office of Energy SFOE, 2024, Photovoltaic funding policy and usage strategy of photovoltaic potential

[17] Prognos, 2021, Energy Perspectives 2050+, Technical Report

[18] The background to this lies in the requirements of the Federal Act on Spatial Planning (SPA), as described in Section 4.3.4, according to which solar power plants located within agricultural land are considered site-specific provided that, in addition to generating electricity, they do not impair agricultural interests and either bring benefits to agricultural production or serve agricultural experimental and research purposes.

[19] Markstaler, M., 2023, Agricultural photovoltaics for specialist crops

[20] Federal Office for Spatial Development ARE, 2025, Freestanding photovoltaic plants

government's first step towards assessing the potential for ground-mounted PV. Among other things, the report states that, from the federal government's perspective, around 6 percent of the country's land area (240 000 ha) comprises areas worthy of consideration and should therefore be investigated by the cantons (including agricultural and alpine land[21]). However, the potential of these areas for electricity generation is not defined as this would require further assessment of the sites – for example, regarding electrical infrastructure – additional cantonal interests, and a comprehensive weighing of interests, particularly in the case of agricultural land. The theoretically possible production that could be achieved through ground-mounted PV on these areas can, however, be roughly estimated at 222–485 TWh using the assumptions of the ARE and SFOE[22].

Table 1 provides an overview of the potential and its share of electricity generation during the winter half-year for various types of PV, though without specifying the potential for ground-mounted PV. Compared with the current expansion (Section 2.2), it can be assumed that the share of electricity generation during the winter half-year will increase as the potential is increasingly exploited.

Potential of PV in Switzerland

Technology	Potential	Of which in the winter half-year[23]	In percent
Rooftop PV	55 TWh	14.9 TWh	27%
< 30 kW	29 TWh		
30–100 kW	13 TWh		
> 100 kW	12 TWh		
Façade PV	20 TWh	7 TWh	35%
Infrastructure PV	4 TWh	1.1–1.4 TWh	27–35%
Alpine PV	6 TWh	2.4–3 TWh	40–50%
Agriculture PV	14 TWh	3.8 TWh	27%
Ground-mounted PV	*222–485 TWh*	–	–
Total	**99 TWh**	**29.2–30.1 TWh**	**~30 percent**

Table 1: Potential and share of electricity generation in the winter half-year for different PV types

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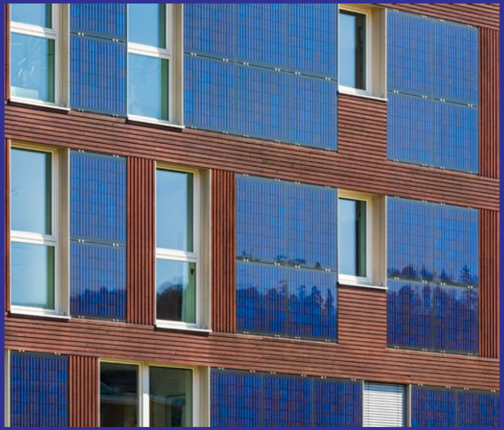
[21] These areas also include alpine regions. These areas, or a subset thereof, are explicitly identified by the SFOE as having a potential of 6 TWh. It is possible that the areas in the alpine region taken into account by the ARE have a higher potential than the 6 TWh identified by the SFOE. Parts of the agricultural PV potential could also overlap with the estimated ground-mounted PV potential. Installations on crop rotation areas (FFF) and ILNM (Federal Inventory of Landscapes and Natural Monuments of National Importance) are not taken into account. Including them would increase the area under consideration to 483 000 ha. The partial overlaps between the various ground-mounted categories make it difficult to determine the potential precisely.

[22] 0.25–0.87 GWh of winter electricity production per hectare (ARE), combined with 27–43 percent of production in the winter half-year (SFOE)

[23] The proportion of winter electricity is subject to many influencing factors such as location, slope and orientation, and should be regarded as an average value across the different types of installations.



Rooftop PV plants make use of existing space, are usually easy to install and can be easily integrated into existing infrastructure. They do not require any additional land use and usually allow a significant proportion of the electricity generated to be utilised through direct own use. The SFOE estimates the potential at 55 TWh per year, 27 percent of which is generated during the winter half-year (it is assumed that the winter share can be increased from the current level of 25.8 percent by optimising orientation, for example).

Facade PV plants are similar in use to rooftop lants, except that they are mounted vertically on building facades. The steep angle of inclination means that the annual output per installed kWp is lower, but the proportion generated during the winter half-year is often significantly higher than with rooftop PV plants. Rooftop and façade plants can be easily combined. The SFOE estimates the potential at 20 TWh, 35 percent of which is generated during the winter half-year.

Infrastructure PV plants are installed on existing structures in a similar way to rooftop or façade plants. They are installed, for example, on noise barriers, above car parks or along railway lines and motorways. As these areas are used for multiple purposes, no new land is required, and there is often little or no conflict of use. Infrastructure PV plants are generally not intended for use in combination with own use. The SFOE estimates the potential at 4 TWh, 27–35 percent of which is generated during the winter half-year.

Alpine PV plants are ground-mounted plants in alpine regions above 1500 metres. These benefit from less fog, additional sunlight due to snow reflection, and colder (= more efficient) modules. However, the installation and maintenance of such plants is more challenging due to the alpine location, and the impact on sensitive ecosystems as well as changes to the landscape are often viewed critically. The SFOE estimates the potential at 6 TWh, 40–50 percent of which is generated during the winter half-year.

Agricultural PV plants are designed in such a way that the agricultural use of the land is preserved. However, they are significantly more complex to plan than conventional ground-mounted PV plants. In this report, we use the term agricultural PV for plants that enhance agricultural production, which is possible with permanent crops. The SFOE estimates the PV potential on permanent crop land at around 14 TWh per year, approximately 27 percent of which is generated during the winter half-year.

Ground-mounted PV plants are plants on open land outside the alpine region, such as on meadows, fallow land, gravel pits, landfill sites and former industrial or military sites. These plants allow for simple alignment, optimised module layout and economies of scale, which can help to reduce costs. As described above, it is not yet fully clear to what extent agricultural land (excluding permanent crops or crop rotation areas) can be included, so the usable potential cannot currently be reliably quantified.

Innovations in PV modules

Category	Perovskite-silicon tandem modules	Thin-film perovskite cells
Technology	Multilayer module structures with both silicon as well as perovskite cells	Perovskite solar cells as semiconductors
Technology readiness level*	7 to 8	7 to 8
Potential	• Up to 20 percent higher current yield per m² than crystalline silicon modules • Higher output in diffuse light, which could slightly increase winter production (not quantified)	• Expected production cost reduction of 30 percent • Can be used on flexible and lightweight substrates, enabling new applications
Challenges	• Uncertainty regarding shelf life and stability of the technology • Production costs currently higher than for crystalline silicon modules	• Rapid degradation due to moisture and UV radiation • Production costs currently higher than for crystalline silicon modules
Opportunities for large-scale deployment	High	High
Impact on the energy system	Insignificant	Insignificant

Table 2: Potential and challenges of innovations in PV cells and modules

*TRL: Technology readiness level, scale from 1 conceptual to 9 implemented

2.4
Innovation

Today's PV plants almost exclusively use crystalline silicon modules. While no disruptive breakthroughs are expected, innovations in cell materials and module designs could increase efficiency, expand solar potential and reduce costs. In particular, tandem modules made of silicon perovskite and thin-film perovskite cells are expected to become leading technologies in the next ten years.

In addition to innovations in the field of PV cells, there are also approaches to using solar energy in a different way or at other locations. In Switzerland, floating PV plants are being tested in alpine regions, promising similar benefits to those of alpine PV. However, suitable space is scarce and early demonstration plants present significant technical challenges. Floating PV plants could also be installed on lakes such as quarry lakes in the Swiss Mittelland region, as has proven a successful application in France. Alternatives such as concentrated PV have no significant potential in Switzerland due to insufficient solar radiation levels and are also less competitive internationally than conventional PV technologies.

2.5
Battery storage for PV plants

Batteries make it possible to store electricity over a certain period of time, typically for seconds up to a maximum of a few days. They are already technologically advanced and have found their way into the electricity system thanks in part to a sharp decline in costs in recent years. They can take on a wide range of tasks in this field as they stabilise grids, shift supply to demand and are increasingly being used as storage units in private households or businesses in combination with PV plants. However, they are not suitable for seasonal storage, i.e. shifting

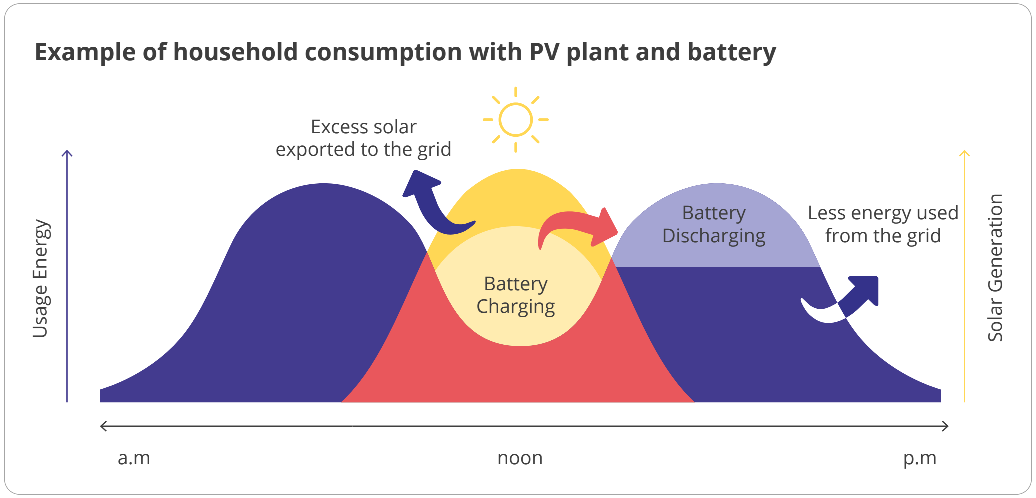

Example of household consumption with PV plant and battery

Figure 5: Example of progression of electricity demand and PV production of a household with home storage. A considerable part of the electricity produced during the sunny hours can be shifted to later hours, which increases the share of own use.

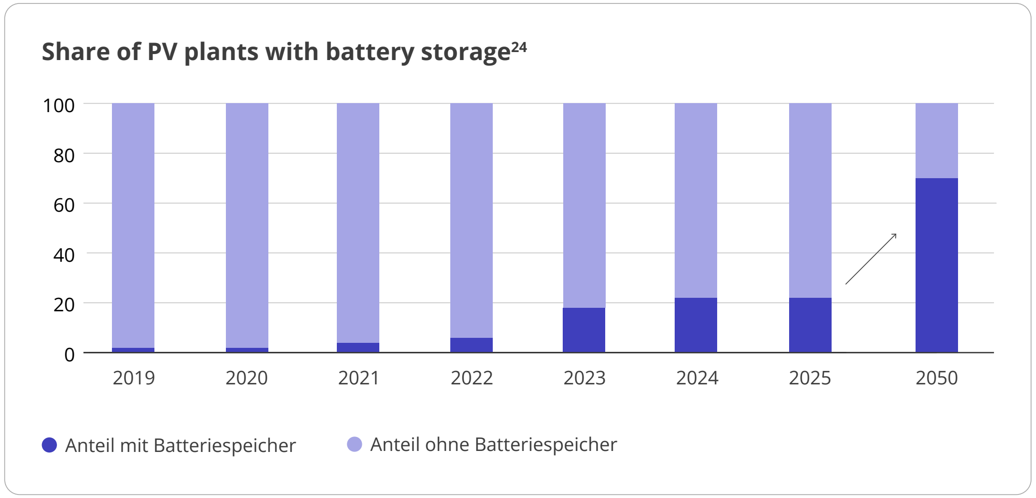

Share of PV plants with battery storage[24]

Figure 6: Historical development of installed PV plants equipped with battery storage. The SFOE is aiming to reach around 70 percent by 2050.

electricity from summer to winter. This report focuses on storage in combination with PV plants.

A battery storage system makes it possible to consume more of the electricity generated by the PV plant yourself, rather than feeding it into the grid. As soon as the sun shines strongly, the PV plant often produces more electricity than the household needs at that very moment. Without a battery, this surplus would be fed into the grid. A home storage system can absorb this energy and store it for later use – for example, for the evening when the PV plant is no longer supplying electricity. This means the solar power generated during the day can be used at a later time, and the own use of a PV plant can be optimised.

In recent years, the proportion of PV plants that are installed or retrofitted with batteries has risen steadily.[25] By the end of 2025, the proportion of PV plants with battery storage stood at around 25 percent[26]. In its Energy Perspectives 2050+, the SFOE assumes that

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[24] SFOE, 2024, 2022 and 2020, solar energy statistics
[25] Swissolar, 2026, Battery storage
[26] The data for 2025 is not yet available, but the proportion can be estimated.

around 70 percent of PV plants in Switzerland will be equipped with battery storage by 2050.

For a battery storage system, the efficiency indicates how much energy can be reused after a full charge and discharge cycle, once conversion losses have been deducted.[27] Current battery storage systems achieve values between 70 and 90 percent (round-trip).

There are currently no national subsidy schemes for battery storage in Switzerland.[28] Support measures were in place in some cantons, but these have been discontinued since 2025.[29] However, a significant change will be implemented from 2026 when the grid usage fee will be refunded for electricity that is first stored temporarily in the battery and later fed back into the grid.[30]

2.6
Grid integration

The large expansion of many decentralised PV plants, especially on rooftops, is placing new demands on the grid infrastructure. Historically, the grids were designed for a predominantly one-sided flow of electricity: from large, central generators via the transmission and distribution grid to end customers. With decentralised feed-in, this flow is reversed depending on the situation. If local PV generation exceeds consumption, the surplus electricity is fed into the distribution network. This is then supplied to other consumers or, in the event of sustained overproduction, transferred to higher-level grid tiers.

Until now, the distribution grid was designed primarily according to the demand for electricity and the peak load to be served. As long as the PV feed-in capacity remains below the local grid capacity, integration is not critical. However, if the cumulative feed-in exceeds the local absorption capacity, measures are required. Three key measures are explained in more detail below: feed-in limits, flexibility measures (e.g. battery storage, controllable demand) and targeted grid expansion.

Feed-in limit: The feed-in capacity of PV plants can be specifically limited in order to protect the grid from overloading and ensure stability. In this process, the inverter is controlled in such a way that power can be fed into the grid only up to a defined level. From the perspective of the PV plant operator, the energy remains available for own use. This is efficient because power peaks contribute little to annual generation but place a disproportionate strain on the grid. For example, if the feed-in capacity is limited to 70 percent, only around 3 percent of the annual production is lost, whereas if the feed-in capacity is limited to 50 percent, just under 20 percent is lost.[31] In the case of a PV plant with an east-west orientation and own use, the decline in annual production is reduced to just 6 percent despite halving the feed-in capacity, and it is even more pronounced at 70 percent. The loss of production also occurs predominantly during periods of very high solar power production, when electricity market prices are typically particularly low – that is the value of unused electricity is typically low.

The Electricity Supply Act[32] already allows distribution network operators to limit solar power plants at the grid connection point. However, according to the ordinance, this limit must not exceed 3 percent of the energy generated annually, which corresponds to a nominal power limit of around 70 percent.

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[27] Neoom, 2026, Efficiency of the battery system
[28] An exception to this is the reduced grid cost contribution for own use, which can be increased through the use of battery storage systems (see Section 4.2)
[29] Swissolar, 2025, Battery storage with photovoltaics 2025. Some communes, such as Meilen in the canton of Zurich, still offer subsidy schemes for battery storage systems.
[30] Art. 14a(4) Electricity Supply Act, cf. Swissolar, 2025, Battery storage with photovoltaics 2025
[31] Bucher, 2025, Incentives for system-friendly network connection of photovoltaic plants, implementation proposal to relieve the burden on distribution networks
[32] Art. 17c Electricity Supply Act

The use of this so-called guaranteed consumption for load curtailment is restricted solely to purposes that benefit the grid and is not designed to reduce long-term electricity overproduction. However, the distribution network operator or other stakeholders could – in addition to the guaranteed consumption – also access the flexibility of PV plants (particularly in the form of load curtailment) on a contractual basis.

Flexibility measures: Flexibility measures, such as battery storage, and controllable demand, such as heat pumps and electric vehicles, are gaining in importance with the increasing expansion of distributed power generation. If they are used in a ways that benefit the grid, electricity consumption, generation and storage can be postponed or controlled in a targeted manner to reduce load peaks in the distribution grid. This can help to limit the impact on the grid infrastructure, especially with high PV feed-in. A key factor in behaviour that benefits the grid is that flexibility is activated specifically during the hours

Background: **Composition of electricity tariffs and dynamic components**

Generally speaking, the electricity tariff in Switzerland consists of three components: the energy tariff (procurement and distribution), the grid usage tariff and charges and fees (e.g. grid surcharge and cantonal charges). The subsidies for renewable energies (7 percent of the costs) are financed by the grid surcharge, which currently stands at 2.3 cents/kWh. Dynamic energy tariffs apply exclusively to the energy component and dynamic grid usage tariffs apply exclusively to the grid component, while charges continue to be predominantly fixed at a given time.

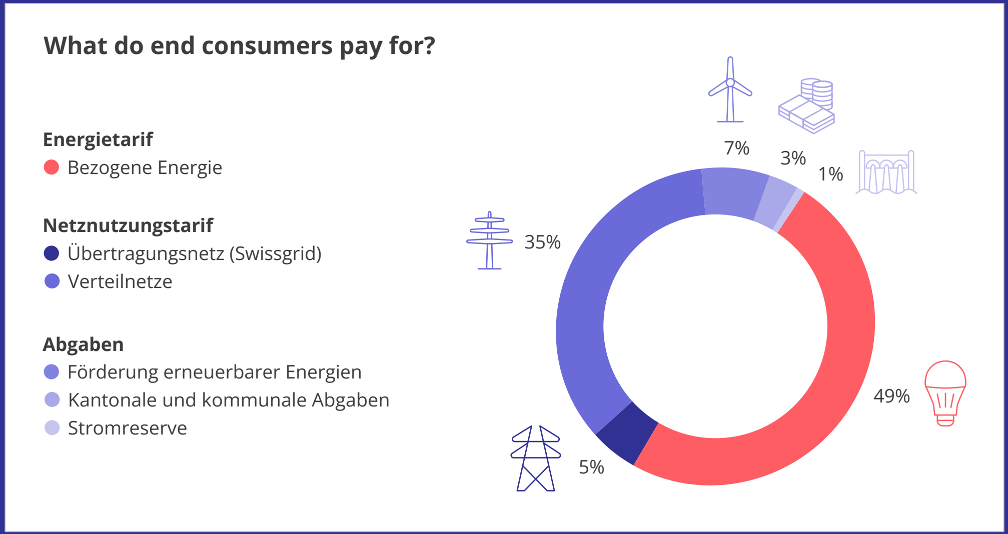

Figure 7: Source: Swissgrid, 2026, The electricity price in focus

Dynamic energy tariffs send short-term price signals from the electricity market directly to end customers and are therefore fundamentally different from traditional fixed or high/low tariffs. While there is already a clear regulatory framework for dynamic grid tariffs, there is currently no such framework for energy tariffs. Nevertheless, the first electricity supply companies (e.g. EKZ) have begun to offer dynamic energy tariffs for basic supply customers as well. Dynamic energy products are already largely established for large-scale consumers with a free choice of suppliers and are available in a variety of versions.

The key benefit of dynamic energy tariffs is that end customers with flexible consumers – such as heat pumps, electric vehicles or battery storage – can shift their electricity consumption to times when prices are low and thus reduce their energy costs. At the same time, there is systemic added value, as electricity procurement becomes cheaper for electricity utilities and thus for the whole of Switzerland. In addition – more than a mere side effect – the load on the distribution grid can be reduced, particularly during peak periods[33].

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[33] Eiche, A., Hirth L., Mühlenpfordt, J., 2024, Added value of decentralized flexibility

and at the points in the grid where critical bottlenecks arise from the grid's perspective. This requires suitable control mechanisms and incentives that are based on the actual state of the grid.

The regulatory changes coming into force from 2026 will create a regulatory framework for more incentives that benefit the grid. Based on the Federal Act on the Supply of Electricity (StromVG, Omnibus Bill) and the revised Electricity Supply Ordinance (StromVV), dynamic and locally differentiated grid tariffs will be made possible. For the first time, these explicitly allow distribution network operators to structure grid usage fees according to time and location, thereby sending targeted price signals to activate flexibility that benefits the grid. The first distribution network operators, including CKW[34], introduced dynamic grid tariffs in 2026. However, it remains to be seen exactly how dynamic and local grid tariffs should be structured to effectively and reliably harness flexibility for the benefit of the grid. This will become clear only through practical implementation and the accompanying learning processes.

Grid expansion: The expansion of the distribution grid is another key measure. However, it is complex to implement this because cables and transformers have to be reinforced and transformers adapted or expanded, which requires significant investment, time and specialised personnel. In addition, many of these measures are subject to lengthy approval and planning procedures (including multiple levels of appeal). It may also be necessary to follow the authorisation procedures and expropriation proceedings in certain circumstances. There are also uncertainties regarding planning. For example, it is not clear how widespread PV, heat pumps and electric mobility will become among end customers, and when and in what form will they be used.

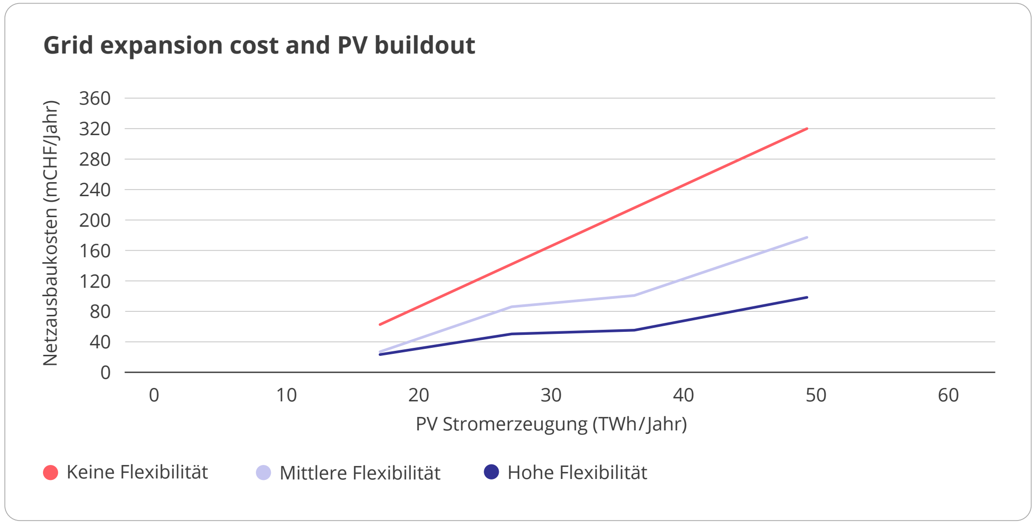

Figure 8: Additional grid expansion costs depending on PV power generation and available flexibility. Modernisation of the existing grid is not taken into account here.

Historically, the expansion of the distribution grid was primarily driven by growth in electricity demand. In future, too, increasing electrification – particularly through heat pumps and electric mobility – is likely to necessitate demand-driven grid expansion. The increased roll-out of decentralised PV plants may also trigger further PV-driven grid expansion, particularly in grid sections with high simultaneous feed-in and limited capacity. Integrating electricity generation from PV plants into the electricity grid may therefore incur additional grid costs beyond the expansion already required to meet demand.

ETH Zurich collaborated on a comprehensive analysis of the expansion of the distribution grid for this project (see box below). The results show that growing electricity demand (e.g. from heat pumps and e-mobility) in par-

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[34] CKW, 2026, Electricity products

ticular requires a largely demand-driven grid expansion of around CHF 40 to 50 million per year[35] at grid levels 4–7, across Switzerland as a whole. Depending on future PV expansion and the extent to which flexibility measures such as feed-in limits, flexible load control and battery storage are utilised, annual expansion costs could rise significantly. In scenarios with high PV expansion (around 50 GW by 2050) and only moderate use of these measures, the annual costs for distribution grid expansion rise to up to CHF 230 million. The calculated expansion costs are in addition to the costs that network operators incur annually for routine investments to address wear and tear, as well as for regular maintenance and replacement measures.

Methodological note

Explanation of ETH grid study

	Feed-in limit	Demand flexibility		Battery storage
		Electromobility	Heat pumps	
No flexibility	100% at the building connection box	No flexibility	No flexibility	No batteries
Moderate flexibility	70% at the building connection box	Reduction of charging sessions for private charging (home + work) in the evening by 20%	No flexibility	0.8 kWBESS/kWpPV for new plants C rate (kWh/kW): 2
High flexibility	50% at the building connection box	Reduction of charging sessions for private charging (home + work) in the evening by 50%	Group-by-group deactivation of HP between 6 p.m. to 10 p.m. (compensation afterwards)	1 kWBESS/kWpPV for new plants C rate (kWh/kW): 1.5

Table 3: Included measure in “medium flexibility” and “high flexibility”

The Research Center for Energy Networks FEN at ETH Zurich was commissioned to quantify the necessary expansion of the distribution grid under various development scenarios for the electricity system in Switzerland. FEN worked with EBP to regionalise scenarios and create time series for end users. The focus here was on the effects of various expansion scenarios for rooftop PV. Specifically, the total costs (CAPEX+OPEX) of network expansion were to be quantified. The integration measures mentioned above were taken into account: Feed-in limits, battery storage and controllable demand. The study examined the necessary grid expansion on the CKW grid, which comprises 20 high-voltage medium-voltage substations and downstream grids (NE4–7), supplies over 70 communes with more than 57 000 grid connection points (building connection box), and handles an annual load of around 1 TWh. The national impact was determined by extrapolation to the whole of Switzerland. The calculation encompasses the following steps:

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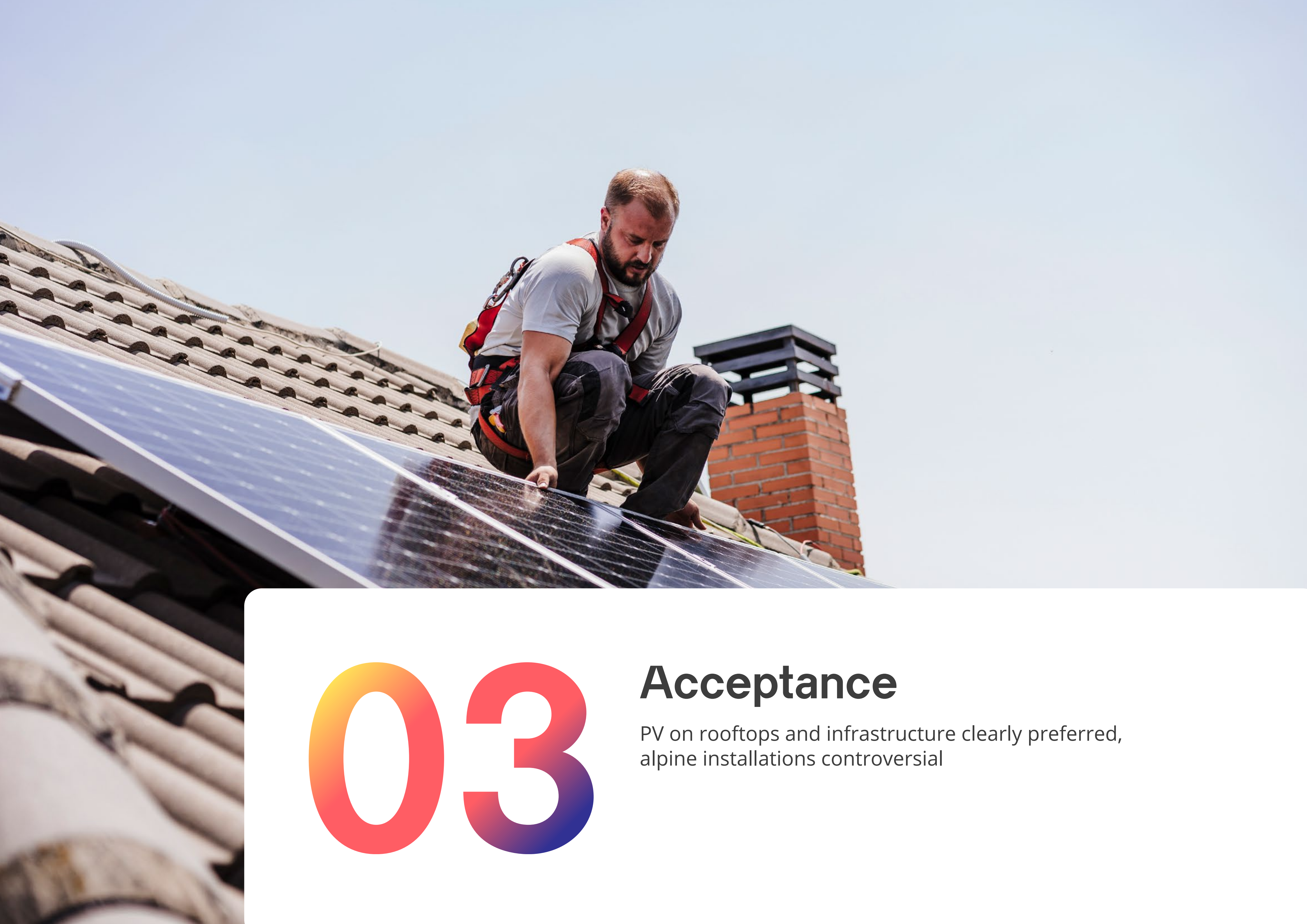
[35] This scenario assumes a modest expansion of PV capacity as a complete halt to PV expansion by 2050 is not realistic. However, expansion is falling sharply as the rate of expansion is only around 15 percent of that seen in recent years. Demand is growing by around 24 TWh. The range in the figures stems from the fact that two scenarios with different degrees of flexibility in demand and PV were calculated.

- **Development of the power system (scenarios) and flexibility (sensitivities):** Six scenarios were analysed; in four of them, the expansion of PV differs. Demand development is the same in all scenarios and includes an increase in electricity demand mainly due to the electrification of mobility and heating as well as population growth, mitigated by efficiency gains. Each of the four expansion scenarios is examined with “medium flexibility” and “high flexibility” – which differ in feed-in limits, demand flexibility and the number of battery storage units (see table below). In addition, a more theoretical sensitivity analysis was carried out without flexibility (i.e. without demand flexibility, PV feed-in limits and without batteries) in order to determine the maximum grid demand for the scenarios.

- **Regional breakdown of electricity demand and generation and greater flexibility:** the scenario parameters are defined at the national level and broken down regionally at the municipal level by calibrating the bottom-up approach for the modelled spread of e-mobility, heat demand and PV. The bottom-up approach makes it possible to distribute the scenario parameters at building-level spatial resolution for the entire study area (CKW supply area). A variety of parameters are taken into account for each load and generation type to distribute demand. Subsequently, annual load profiles with a temporal resolution of 15 minutes up to the year 2050 are calculated. In order to investigate the impact of flexibility on grid expansion requirements, the load profiles for e-mobility and heat pumps, as well as the generation profile for PV, were modified by the following measures: the probability of charging electric vehicles in the private sector was reduced in the evening hours (peak household load) and the heat pump load was reduced more restrictively during this period. The generation profile for PV was throttled at the grid connection point, i.e. at the building connection box (after the inverter and the coverage of the building demand). The time series are generated for the whole year for each scenario and each sensitivity analysis. The result: a clear, location- and time-specific picture of demand and feed-in as the basis for targeted grid planning.

- **Power flow calculation in the grid (CKW):** Grid planning is carried out on the basis of these time series: Coupled MV/LV load flow analyses per substation and time step identify thermal overloads and voltage violations. Costs for traditional measures (cable/transformer amplification, underground cabling, etc.) as well as for NOVA options (grid optimization such as PV Q(U) regulation and curtailment) are calculated and compared. The costs are calculated as annual annuities with a WACC of 5 percent and O&M costs (2 percent); ancillary structural services (e.g. civil engineering, transformer buildings) are taken into account on a rule-based basis. Result: Grid expansion costs for the CKW grid for each grid level.

- **Upscaling:** The investment results of the CKW network for NE4–7 are used to extrapolate the results to Switzerland using a scaling methodology. Each region supplied by a CKW high-voltage medium-voltage substation is treated as an energy supplier and the ElCom clustering method for 630 energy suppliers is used for extrapolation. This is based on energy density and population density (calculated on the basis of cable/line lengths and annual energy volume). This results in an overall estimate of grid expansion costs and the measures for each scenario at the national level.



03

Acceptance

PV on rooftops and infrastructure clearly preferred, alpine installations controversial

There is a very high level of acceptance in Switzerland for **PV plants on roofs, facades and infrastructure**. Surveys show that a large proportion of the population supports the expansion of renewable energies, with particular emphasis on the desire for security of supply and climate-friendly domestic energy production. National surveys regularly confirm that there is over 92 percent approval for PV plants on roofs, facades and infrastructure, which is the highest value of all energy generation technologies.[36] This is evident not least in the rapid expansion of PV plants in Switzerland in recent years (see Section 2.2).

Public acceptance of **alpine PV** is lower than that of rooftop PV. The same national survey shows a level of support of around 50 percent for 'large solar power plants in the mountains on open meadows'. Although this approval rate is lower than for wind energy or new nuclear energy, it is higher than for new gas-fired power stations. At the local level, the requirement for alpine PV set out by Solarexpress for the approval of the host commune (Energy Act Art. 71a (3)) is a decisive hurdle. Where a vote took place – typically in a municipal parliament – more than half of the projects were approved.[37] As of January 2026, only four projects with a total expected annual production of 0.07 TWh were under construction or had been partially commissioned.[38]

To date, there are hardly any reliable studies on social acceptance of **agricultural PV** in Switzerland. The technology is new, and there are only a few installations. Furthermore, the definition of agricultural PV is inconsistent in the literature and in practice due to the range of possible installation types and, in particular, the distinction from ground-mounted PV. In general, however, it can be stated that Agricultural PV that does not impair agricultural production (see Section 2.3, SFOE definition) enjoys a very high level of support. This is also confirmed by recent surveys. If the impact on agricultural use increases, acceptance decreases accordingly. The same survey found that installations that are well integrated into existing infrastructure (such as greenhouses or polytunnels) are significantly better accepted. Smaller installations are also better accepted than medium-sized to large projects. Local ownership further increases approval. Acceptance of agricultural PV is highest among urban and left-wing population groups, although it also enjoys majority support among right-wing and rural population groups.[39]

Similarly, there is currently only limited scientific / empirical data available regarding the acceptance of **ground-mounted PV** in Switzerland. A recent survey shows approval ratings on a similar scale to those for alpine PV, at around 50 percent.[40] The survey reveals differences between political groups as around 60 percent of people on the right are opposed to ground-mounted PV plants, and slightly more than 50 percent of the central parties do not support ground-mounted PV plants. Around 60 percent of the people on the left support ground-mounted installations. However, acceptance is likely to vary greatly depending on the location. Installations on land that has already been used for other purposes (e.g. landfill sites, brownfield sites) and with low visibility are likely to enjoy greater acceptance than installations in unspoilt landscapes. This interdependence means that the SFOE also classifies potential suitable areas for ground-mounted PV according to different conservation and land-use interests. Accordingly, sites with little or no conservation interest and high land-use interest can be identified; such installations are likely to enjoy higher levels of acceptance.

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[36] gfs.bern, 2025, Final report – Wave 4 energy supply security study
[37] Alpine PV competence, 2026
[38] SRF, 2026, The Solarexpress delivers remarkable insights
[39] Agrivoltaics can reduce political polarization and local opposition to solar energy on land, Lukas Fesenfeld et al., 2026
[40] Agrivoltaics can reduce political polarization and local opposition to solar energy on land, Lukas Fesenfeld et al., 2026

04

Legal and regulation

Rooftop PV is only subject to notification requirements, while ground-mounted, alpine, and agri-PV face regulatory challenges. Current subsidy scheme is comprehensive.

In brief

- The current subsidy scheme is comprehensive and varies according to the type of plant. PV plants receive investment grants of up to 30–60 percent of the investment costs (depending on own use) or a sliding-scale market premium of up to 9 centimes/kWh (for plants larger than 150 kW without own use), as well as various bonuses (tilt angle, winter electricity and car park bonuses). Alpine PV is subsidised at up to 60 percent of the investment. Plants with a capacity of less than 3 MW and an annual output of less than 5 GWh also benefit from an obligation on the part of the distribution network operator to purchase and pay for their electricity. A statutory minimum remuneration also applies to solar power plants up to 150 kW (up to 6 or 6.2 centimes/kWh).

- Implicit support in the form of a reduced share of grid costs for own use is a key economic advantage, but this depends on the tariff structure of the respective distribution network operator. Own use enables savings of (currently on average) around 14.5 centimes/kWh. However, this advantage is made possible by a redistribution of network costs to non-PV households that is not based on the polluter-pays principle. Tariff changes such as dynamic network tariffs or performance-related components could (partially) reduce these benefits.

- Under the Spatial Planning Act, rooftop and façade PV plants on existing buildings generally do not require planning permission but only a notification. In contrast, ground-mounted, alpine and agricultural PV must undergo planning permission procedures, the complexity of which varies depending on the location and size of the installation.

- The Acceleration Decree is intended to streamline these procedures but has not yet been implemented nationwide. It provides for combined cantonal planning approval procedures that bring together land-use planning and building permits. However, the cantons still need to transpose the new requirements into cantonal law.

- Unlike in the field of wind energy, for example, there are no cantonal suitable areas for ground-mounted PV at the start of 2026.

4.1
Current subsidies

Today, PV plants can rely on various funding instruments (see Figure 9). Investment grants and a sliding-scale market premiums are available depending on the performance class and the potential for own use. There are also individual bonuses for tilt angles, winter electricity and installation space. In addition to this support, the current regulations provide further benefits through own use, which are described in the next section.

4.1.1

Investment grants

Under the Energy Act, PV plants are eligible for an investment grant[41]. With regard to the maximum subsidy rates, the Act distinguishes between plants with and without own use. For plants without own use, the rate is higher, at a maximum of 60 percent of the investment costs; for plants with own use, which also benefit from savings on grid tariffs, the rate is lower, at 30 percent.

The Federal Council determines the specific subsidy level for plants with own use by decree. For example, in 2026, plants larger than 150 kW with own use will receive 250 CHF/kW, whereas auctions will be held for those without own use. For plants smaller than 150 kW, the one-off remuneration ranges from 250 CHF/kW to 450 CHF/kW[42].

The Solarexpress scheme has also created a subsidy of up to 60 percent of investment costs for alpine PV plants, provided their planning application was made public by the end of 2025. Unlike the investment grants for other types of plants, a site-specific cost-benefit analysis is carried out, rather than setting flat-rate amounts per kW.

4.1.2

Sliding market premium

When the revised Energy Act comes into force in 2025, PV plants larger than 150 kW that do not generate electricity for own use will be able to apply for a sliding-scale market premium as an alternative to an investment grant. The remuneration rates are determined by auction[43]. The SFOE also sets a maximum permissible rate in advance, which stands at 9 centimes per kWh as of 2025. If the reference market price[44] falls below this remuneration, the plants receive the difference as a subsidy; if it exceeds it, they must repay the excess.

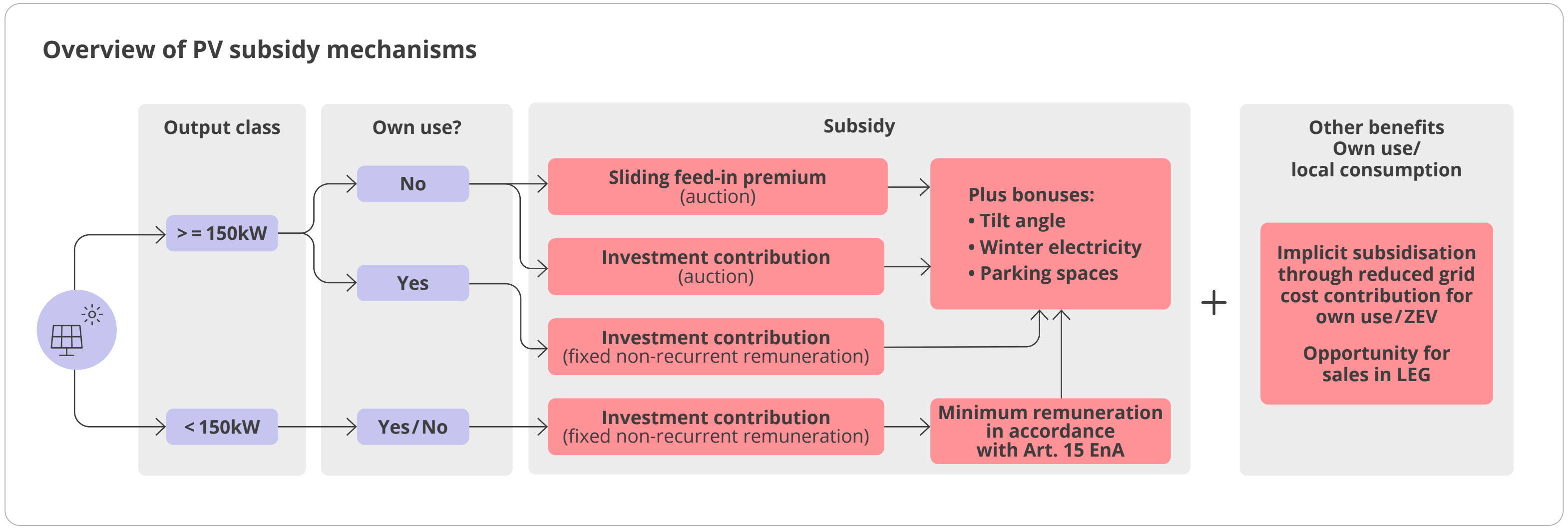
Overview of PV subsidy mechanisms

Figure 9: Overview of different subsidy mechanisms for PV in relation to plant sizes and own use

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[41] Art. 25 Energy Act
[42] Annex 2.1 Renewable Energy Ordinance
[43] Art. 25a of the Energy Act, Art. 38a of the Renewable Energy Ordinance, Art. 30c of the Renewable Energy Ordinance
[44] The reference market price corresponds to the weighted average of the day-ahead price. The weighting is based on the nationwide feed-in of the relevant technology (see Art. 15 REO).

The sliding-scale market premium provides ongoing income security over a fixed period of 20 years by offsetting fluctuations in market prices. On the other hand, the investment grant is a one-off grant provided at the start of the project and is intended to directly reduce investment costs. However, previous auction rounds suggest that the sliding-scale market premium has met with only limited interest among project developers, who prefer the investment grant.[45]

4.1.3

Bonuses

The Federal Council has introduced various bonuses for specific types of plants at the ordinance level. In addition to the basic subsidy (flat rates or auction), project developers can claim the following bonuses:

- A tilt angle bonus of 200–400 CHF / kW for plants with an inclination of 75° or more.
- Winter electricity bonus for large installations with a specific winter electricity production of more than 500 kWh per kW of installed capacity.
- Car park bonus of 250 CHF / kW for uncovered car park areas

The winter electricity bonus is intended to promote the expansion of photovoltaic plants that generate a particularly high amount of electricity in winter. The amount of the bonus depends on the specific winter production and is available to all types of plants. The relevant electricity production (specific additional winter electricity production) corresponds to the amount of energy that a plant delivers per kilowatt of capacity during the winter half-year and exceeds the threshold of 500 kWh / kW. The resulting specific winter electricity surplus production divided by the total specific winter electricity production is then multiplied by 17.5 centimes / kW to obtain the actual winter electricity bonus. This is paid out only for electricity fed into the grid during the winter half-year and cannot be combined with the tilt angle bonus.

4.1.4

Obligation to purchase and pay

Solar power plants with a maximum output of less than 3 MW and an annual production (after own use) of less than 5 GWh also benefit from the statutory obligation to purchase and pay for electricity[46]. Under this obligation, distribution network operators must purchase the electricity. In general, remuneration is based on the nationally harmonised price, which corresponds to the quarterly technology-weighted market price[47]. With the implementation of the Acceleration Decree, remuneration for electricity from renewable energy sources will in future be based on the market price at the time of feed-in. The remuneration does not take into account either balancing energy costs or marketing costs, which are incurred by the distribution network operator and result in additional costs. Furthermore, installations smaller than 150 kW receive a minimum remuneration; for installations without own use, this is 6.2 centimes / kWh, while installations with own use receive up to 6 centimes / kWh[48].

The distribution network operator will pass on the above-mentioned additional costs in the basic supply tariff. This results in increased basic supply costs for consumers. Conversely, however, consumers on the basic supply tariff do not benefit from regulated solar power remuneration when market prices are high as it must be remunerated at the high market price during such periods.

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[45] In the three auctions conducted by Pronovo in 2025, the sliding-scale market premium resulted in awards of just 2.5 MW, despite a total auction volume of 80 MW. In contrast, for the investment grant, contracts were awarded for over 120 MW, with an auction volume of 160 MW.

[46] Art. 15 Energy Act

[47] Art. 12 Energy Ordinance, Art. 15 Renewable Energy Ordinance; However, plant operators and distribution network operators can also agree on a different remuneration.

[48] plants with an output of less than 30 kW receive 6 cents / kWh, larger plants only receive these on a pro rata basis (Art. 12 EnV)

As part of the Acceleration Decree, the Swiss Federal Parliament has decided to introduce remuneration at market prices at the time of feed-in and to allow for the potential suspension of the minimum remuneration in the event of negative prices. Accordingly, the minimum remuneration will in future be paid as the difference between the quarterly reference market price and the actual price. According to the consultation draft, the Federal Council wishes to refrain from suspending the minimum remuneration in the event of negative prices for the time being.

Future remuneration at market prices at the time of feed-in represents a necessary incentive for system-oriented control of production. However, as long as the minimum remuneration is not suspended in the event of negative prices, the market price signal will be distorted, and installations will continue to have an incentive to feed in against market signals.

The revision of the feed-in tariff therefore represents an important step towards market-oriented incentives and, therefore, better integration of (small-scale) PV. At the same time, however, suspending the minimum remuneration in the event of negative prices would be important in order to completely remove the perverse incentives.

4.2

Implicit subsidies through reduced grid cost contribution for own use

In the case of own use, i.e. the consumption of one's own electricity on-site, the energy price of the grid usage fee and levies – grid surcharge (in accordance with Art. 35 EnA and Art. 35 REO: 2.3 centimes / kWh), specific cantonal and municipal levies, electricity reserve – can be saved on this electricity. As grid usage fees and levies currently account for around half of the total electricity price (see Section 2.6 Grid integration), this is highly lucrative. Rooftop PV plants in particular can benefit from own use as they are often located in places where electricity is consumed. The reduced grid cost contribution for own use constitutes an implicit subsidy. The effects on economic viability are explained in more detail in Section 5.2.

It is now also possible for several parties to reduce their grid cost contribution through own use by forming a so-called (virtual) own use community (ZEV) (in accordance with the Energy Act). The ZEV is characterised by the fact that various consumers with generation capacity connected to a single grid connection join forces vis-à-vis the distribution network operator[49]. Since 2026, the option for local electricity communities (LEG) has also been introduced[50]. LEGs enable end consumers, producers and storage facilities that are connected in the same commune, within the same grid area and at the same voltage level (either all grid level 5 or all grid level 7) but at different grid connection points to exchange self-generated electricity amongst themselves. For this electricity exchanged within the LEG, they benefit from a reduced grid tariff. According to the current regulation, the discount amounts to 40 percent of the grid tariff[51]; if voltage transformation[52] is required for the exchange, it is only 20 percent. As with own use from individual installations, this can reduce the grid cost contribution.

The problem here is that own use leads to a reduced contribution to grid costs. This undermines a central principle of grid tariffing: the allocation of grid costs according to the polluter pays principle[53]. A contribution should be made to cover the cost structure for the use of the grid. To this end, it is important to understand that around 60 to 70 percent of grid costs depend purely on the structural requirements of the grid, in particular the number and location of grid connection points, which largely determine the necessary line

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[49] Provided they achieve a minimum of 10 percent generation output relative to the connected load (sum of the connected loads of the participants)

[50] Art. 17d & 17e Electricity Supply Act

[51] The discount on the grid usage fee covers not only the active energy component but also the basic tariff and any power component. Art. 19h Electricity Supply Ordinance

[52] A voltage transformation is necessary when, although all the parties involved are on the same grid level (e.g. 7), the electricity must be routed via a different grid level in order to be exchanged.

[53] DETEC, 2026, Federal Act on a Secure Electricity Supply from Renewable Energy Sources Amendment to the Electricity Supply Ordinance with entry into force on 1 January 2026 Explanatory report

length.[54] The maximum simultaneous power drawn or fed into the grid (peak grid load) and the amount of energy transmitted account for a significantly smaller proportion of grid costs, at around 30 to 40 percent. Grid tariffs are therefore designed to enable end consumers to refinance grid costs. Whilst avoiding grid charges represents an economic advantage for PV plants, meaning they contribute less towards covering grid costs, the expansion of PV – even with own use – leads to an increase in grid expansion costs (see Section 2.6).

The reduced grid cost contribution through own use therefore leads to a redistribution of grid costs that is not based on the user pays principle as higher grid costs must be spread across the remaining, lower consumption.[55] Households without the option of PV, in particular, end up paying more.[56] Empirical studies also show that own use leads only to slightly positive or even negative economic effects[57]. For instance, a recent study commissioned by the SFOE demonstrates that battery storage for own use is not economically viable from a plant perspective and is not economically efficient for grid-oriented purposes.[58]

In Switzerland, therefore, adjustments to grid tariffs are being discussed and gradually introduced. This is also to encourage behaviour that benefits the grid. Since 2026, dynamic grid tariffs have been increasingly used, supplemented by demand-based components (e.g. peak prices per kW). This shifts the cost allocation away from fixed energy prices (CHF / kWh) towards actual grid usage (output, time of use). A higher fixed / output-related component in the grid tariff would be consistent with the grid's cost structure. However, grid tariffs should also have an incentive effect[59], i.e. provide incentives for efficient behaviour (peak shaving, load shifting, storage operation)[60] that benefits the grid rather than simply allocating fixed costs on a flat-rate basis.

Ultimately, many of the current economic advantages of own use are tariff-related and work against a user pays allocation of grid costs. An adjustment to grid tariffing could lead to an increase in the grid cost contribution for PV plants with own use as well, thereby (partially) eliminating the implicit subsidy. The economic feasibility analysis therefore presents the subsidy requirement with and without implicit subsidies (see Sections 5.3 and 5.4).

4.3
Spatial planning and approval

The requirements for the planning permission process and the likelihood of obtaining building permission vary depending on the type of PV plant.

4.3.1
Rooftop and façade PV: notification procedure is usually sufficient

Under Article 18a(1) of the Spatial Planning Act (SPA), solar power plants on existing buildings in the building and agricultural zones do not require planning permission (with exceptions, for example, relating to cultural and natural monuments; see Article 18a(3) SPA). The owner therefore generally

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[54] Swiss Federal Office of Energy SFOE, 2021, Further development of grid and energy pricing
[55] Cf. also Hirth, 2025; Bardt, Chrischilles, Growitsch, Hagspiel, & Schaupp, 2014; Schill, Zerrahn, & Kunz, 2017
[56] This effect is also highlighted by ACER, 2025, Getting the signal right: Electricity network tariff methodologies in Europe
[57] Semmelmann, Konermann, Dietze, & Staudt, 2024, Empirical field evaluation of self-consumption promoting regulation of household battery energy storage systems
[58] DETEC, 2025, Demand for energy storage in Switzerland
[59] Art. 14 Electricity Supply Act: Grid tariffs must take account of the objectives of efficient use of electricity. Art 18a Electricity Supply Ordinance: Non-dynamic standard tariffs must include a non-degressive energy component (centimes per kWh) of at least 50 percent.
[60] Unlike energy-saving measures, for example, own use does not result in a net reduction in energy consumption.

only needs to notify the planning authority of the building of a suitably adapted solar power plant. The legislature has stipulated that the interest in energy generation takes precedence over other interests, in particular aesthetic interests (Art. 18a(4) SPA).

4.3.2
Infrastructure PV: diversity requires individual consideration

The wide range of applications for PV plants on infrastructure structures is reflected in the diversity of the relevant legal frameworks and planning permission procedures. This makes it essential to consider each individual case on its own merits. As a result of this diversity, it is not discussed further here.

4.3.3
Ground-mounted PV: classification by category is necessary

The procedures and the possibility of obtaining planning permission for ground-mounted PV plants can be broadly categorised according to two criteria:

- The size of the plant or its contribution to the energy supply (threshold of national interest: average expected production from October to March of at least 5 GWh)

- Planning classification of the site in question (zoning compliance)

To illustrate the aforementioned aspects of spatial planning and authorisation, the following cases are considered:

1st Case
Plants of national interest located in a designated area and included in the cantonal structure plan
If a PV plant meets the requirements relating to the national interest, the proposed site is included in the cantonal structure plan and the land-use plan is in place, the prospects of obtaining planning permission are considered to be good to very good. The communal planning authority is generally responsible for granting planning permission.

The cantons are tasked with designating suitable areas for stand-alone solar power plants of national interest (see Art. 10 of the Energy Act[61]). In future, such PV plants of national interest are to be exempt from the planning obligation under the Spatial Planning Act (Art. 10 (1ter) nEnG). The cantons are then required to ensure, to the extent necessary, that specific land-use plans are adopted or amended. In doing so, they may provide for a (combined) cantonal planning approval procedure that includes, amongst other things, the necessary land-use planning provisions and the building permit (Art. 10 (2) EnA and, for installations of national interest, Art. 14a nEnG). For the provisions in the structure plan as well as for specific requirements at the land-use planning level, the cantons must, as part of their energy strategy, consider how much additional photovoltaic capacity they aim to achieve and what role freestanding solar pow-

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[61] in the version according to the Parliamentary Drafting Committee, see EnA; SR 730.0 and final voting text EnA

er plants should play in this. To assist with this, the Federal Office for Spatial Development (ARE) has published a background document intended to facilitate the identification of suitable areas.[62] However, at the time of publication of this technology report, no canton had yet set out specific targets for ground-mounted PV or a corresponding plan for suitable sites. Experience with the designation of suitable sites for wind power shows that this process can take several years.

The Acceleration Decree provides that, in future, the cantons will be able to combine land-use planning provisions with the actual building permit (so-called cantonal planning approval, Art. 10(2) nEnG). As the cantons have considerable discretion in implementation and must first transpose the relevant provisions into cantonal law, it is not yet possible to comment on the (acceleration) effects of these forthcoming changes in practice.

Background: **Legal framework for spatial planning with a focus on ground-mounted PV**

In order to assess the chances of success of a planning application for a photovoltaic plant, particularly outside the construction zone, it is advisable to first take a look at the legal framework conditions for spatial planning. This overview focuses on ground-mounted PV plants.

According to Art. 22 (1) of the Federal Act on Spatial Planning (SPA), buildings and installations, including photovoltaic plants, may only be constructed or modified with official approval (construction ban subject to approval).

The building permit procedure, which is usually administered by the local authority, checks, firstly, whether the building project is zoning-compliant; secondly, whether the requisite infrastructure is in place; and thirdly, that it complies with all other legal requirements, particularly those relating to building regulations and environmental law. If these prerequisites are met, the project is generally eligible to have the building permit granted.

The first step towards fulfilling the planning requirements of the SPA is the cantonal structure plan. In the structure plan, each canton must indicate how it intends to develop in terms of spatial planning and construction. According to Art. 6 (2)(3) SPA and Art. 8a SPA, the cantonal structure plan must specify the areas that are suitable for the production of renewable energies (so-called suitable areas). According to Art. 10 (1) of the Energy Act (EnA), the cantons must ensure that such suitable areas are defined in the cantonal structure plan for solar plants of national significance.

According to Art. 12 (2) of the EnA and Art. 9a of the Energy Ordinance (EnO), solar plants are of national significance if the average expected production from October to March is at least 5 GWh. In our view, this national interest must be taken into account in all assessments of competing interests required under spatial planning law (particularly when drawing up and issuing cantonal structural plans, municipal use plans and in the building permit procedure).

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[62] Federal Office for Spatial Development ARE, 2025, Freestanding photovoltaic plants

2nd Case

Plants that do not meet the threshold for national interest but are consistent with the intended use of the relevant zone (usually a building zone)

For plants that are typically smaller and do not meet the threshold for national interest, there is generally no entry in the cantonal structure plan. However, the cantons may include sites for PV plants that do not meet the criteria for national interest in the structure plan. Such an entry forms an essential basis for implementation in the (usually communal) land-use plan.

The communes (and, where applicable, the cantonal authorities, depending on the regulations in the canton concerned) may also provide for and designate special zones (building zones) in the land-use plan for such smaller plants, even without an entry in the cantonal structure plan. When making these planning-law determinations, the interests must be weighed up in a way that is appropriate to the level of planning.

The designation of such special zones (building zones) lays the groundwork for developing a specific building project (see in particular Art. 22 SPA). Apart from special cases (e.g. the presence of protected areas), the chances of obtaining a building permit in such a special zone remain intact.

It is not currently possible to assess whether and how the provisions of the Acceleration Decree will affect 'smaller' plants. As explained, these must be transposed into cantonal law.

3rd Case

Plants outside the building zone

If an ground-mounted PV plant is to be erected at a site outside the building zone, the requirement for zoning compliance is not met. In such cases, a building permit is typically

Excursus: **Appeals and complaints**

If a building permit is required, a building application for a PV plant must be made publicly available. As a rule, affected parties (neighbours, environmental protection organisations, etc.) can lodge an objection within the consultation period. In most cantons, appeals are decided within the building permit procedure. This can be followed by an appeal procedure under cantonal law, in which case the cantons must provide for a competent court. The differences between the cantons are considerable: Lucerne, for example, only provides for an appeal to the cantonal court, whereas in other cantons the appellants must first go to the Construction Appellate Court and then to the cantonal Administrative Court (e.g. in the canton of Zurich)[63].

Subsequently, the ruling of the Cantonal Supreme Court can be appealed to the Federal Supreme Court. It should be noted that the Federal Supreme Court exercises a certain restraint when handling such complaints – as planning and construction law are largely governed by cantonal regulations.

Provisions in (local) land-use plans are binding on the landowner, which is why cantonal remedies are also available against these provisions – including, as a last resort, an appeal to the Federal Supreme Court. The legislation on accelerated procedures provides for a cantonal planning approval procedure which, among other things, summarises the planning specifications and the building permit in a (combined) decision by a cantonal authority (Art. 14a nEnA)[64].

In simplified terms, a rule of thumb for the duration of proceedings can be assumed to last around six to twelve months per (appeal) instance.

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[63] According to the explanatory memorandum to the Acceleration Decree (draft by the drafting committee), Article 14c(1)(a) of the New Energy Act provides that only the highest (single) cantonal authority shall be responsible for solar power plants of national interest.

[64] Under Article 14c(1)(a) of the New Energy Act, the only remedy available against such a combined planning approval decision is an appeal to a cantonal court.

granted in the form of an exemption under Article 24 SPA. The requirements regarding the documentation and the level of justification provided by the project developer, particularly in view of the strict balancing of interests required in this case, are considerable. The prospects of obtaining an exemption are rather slim. In addition, there is a significant risk that an exemption granted may be successfully challenged by an appeal.

4.3.4
Agricultural PV plant

Freestanding agricultural PV plants are usually located in agricultural areas (outside the building zone). They are therefore dependent on an exemption under Article 24 SPA. As far as can be ascertained, there is a relaxation of the approval requirements in that such agricultural PV plants connected to the electricity grid may be site-specific if they bring benefits to agricultural production in less sensitive areas or serve corresponding experimental and research purposes. A significant complication for project developers is that such plants are subject to the strict requirements of agricultural land law. There is little practical experience regarding the associated authorisation procedures.

Excursus: **Permitting of grid infrastructure**

If additional lines have to be built for the connection, this entails additional permitting procedures for the grid installations concerned. In Switzerland, a specific permitting procedure is required for the construction of high-voltage installations (from 1 kV) (Art. 16 of the Electricity Act (ElecA)). In principle, this procedure is managed by the Federal Inspectorate for Heavy Current Installations (ESTI), which reviews the submitted documents. In the event of any differences or inconsistencies, the ESTI refers the matter to the Swiss Federal Office of Energy (SFOE).

In addition to the (building) permit, the grid operators are also dependent on acquiring the necessary private legal rights for their construction and operation (namely transmission rights for electricity) from the landowners concerned and compensating them. Since an amicable settlement cannot be reached in every case, the grid operators have the legal right to expropriate the transmission rights (Art. 43 ElecA). Licensing and expropriation procedures (according to ElecA and the Expropriation Act) must be combined. Even in the event that only the expropriation point is disputed, the ESTI will refer the combined application for approval to the SFOE for a decision.

An appeal against the planning approval decision can be lodged with the Federal Administrative Court. However, appeals to the Federal Supreme Court are only permissible under certain conditions.

There is no legal regulation that provides for the coordinated approval of production plants and the associated grid infrastructure. The municipal and cantonal authorities are only obliged to coordinate the respective permitting processes (production plant or grid installation) with the federal authorities.

05

Economic viability

Expensive rooftop PV becomes economically viable thanks to own use, ground-mounted PV is considerably cheaper

In brief

- The profitability of PV depends heavily on the type of plant. Under current regulations, many PV plants are already profitable, although there are significant differences between plant types and a strong reliance on the implicit subsidy provided by the reduced grid cost contribution for own use.

- Costs vary significantly depending on the type of plant and location, as installation and substructure are the main cost drivers (>50 percent), while module costs account for only around 16–28 percent. Economies of scale play a key role as small rooftop PV plants of <30 kW achieve levelised cost of electricity (LCOE) of 105–202 CHF / MWh, while large rooftop plants of >100 kW fall to 48–119 CHF / MWh thanks to economies of scale, approaching the levels of ground-mounted plants (49–109 CHF / MWh). Alpine PV has the highest generation costs at 110–247 CHF / MWh.

- The reduced grid cost contribution for own use is crucial to the economic viability of rooftop PV as it covers up to 45–83 percent of the levelised costs. Without this implicit subsidy, many small plants would be unprofitable.

- Market revenue for rooftop and ground-mounted PV is expected to cover 39 CHF / MWh over the next 30 years, i.e. 30–65 percent of the levelised costs. Market revenue from alpine PV is slightly higher at 42 CHF / MWh, but cover only 26 percent of the levelised costs.

- The need for subsidies varies greatly depending on the type of plant. The subsidy for rooftop PV consists of direct and implicit subsidies. In 2035, the subsidy requirement for rooftop PV plants of <30 kW will be 95 CHF / MWh, and for ground-mounted PV plants it will be 20 CHF / MWh. Larger rooftop PV plans of 30–100 kW and >100 kW with own use actually have no additional direct subsidy requirement thanks to reduced a grid cost contribution. Alpine PV has the highest subsidy requirement at 107 CHF / MWh.

- The market value of a PV plant with battery storage is higher than that of a comparable plant without storage, as own use is increased and a higher market price can be achieved. However, the production costs are 50–80 percent higher, which means that plants with battery storage are not always economically viable.

5.1
Costs and revenues

5.1.1
Cost and revenue assumptions

The levelised cost of electricity for PV plants consist of modules, assembly, planning, inverters, substructure, cabling and transport. The modules themselves now account for only a small proportion of the costs, whereas installation and the supporting structures in particular can make up a large part of the costs. Costs and revenue are influenced in particular by:

- **Plant type and associated installation work:** The installation work varies greatly depending on the type of plant. For rooftop or façade plants, integration into existing buildings is often complex and labour-intensive, particularly in the case of older roofs or unusual roof shapes. Ground-mounted plants benefit from simpler, standardised workflows, while alpine plants incur significantly higher installation costs due to difficult access, weather conditions and longer transport routes. These factors are directly reflected in the costs and make installation the most significant cost driver.

- **Choice of location:** The choice of location and orientation affect installation and grid connection but also have a direct impact on solar radiation and, therefore, on the number of full-load hours a PV plant can achieve. This affects the plant's specific output and determines how large the plant needs to be. To produce the same amount of energy, a plant with lower solar radiation must be larger than one with high solar radiation.
- **Plant size:** As the plant size increases, the specific costs (CHF/kW) decrease as economies of scale can be utilised in terms of materials, planning and installation. Rooftop plants are generally smaller and benefit only to a limited extent from these effects. However, complex projects such as alpine PV also place greater de-

Cost of PV plants in 2025

		Roof < 30 kW		Roof 30–100 kW		Roof > 100 kW	Alpine	Ground-mounted
			With battery		With battery			
CAPEX in million, CHF/MW	**Low costs**	1.8	3.2	1.1	2.6	0.8	3.2	0.8
	Reference assumption	2.1	3.3	1.4	2.6	1.0	4.4	1.0
	High costs	2.5	3.5	1.7	2.8	1.4	6.0	1.2
of which	Labour and administrative costs	12%		6%		4%		
	PV panels	16%		21%		28%		
	Inverters, electrical etc.	16%		16%		17%		
	Construction site security and transport	56%		57%		51%		
OPEX in CHF/MWh	**Low costs**	23	40	14	32	10	19	10
	Reference assumption	33	52	23	41	16	29	15
	High costs	44	62	31	49	24	44	23
FLH in h/a	**Low costs**	1200	1200	1200	1200	1200	1650	1200
	Reference assumption	950	950	950	950	950	1500	1000
	High costs	850	850	850	850	850	1350	800
Own use in %		40%	60%	50%	70%	0%	0%	0%
Years of operation in years		30	30	30	30	30	60	30
WACC[65] in %, real		3.5%	3.5%	3.5%	3.5%	4%	4%	4%

Table 4: Cost assumptions for various PV plants with commissioning in 2025. Showing the reference assumption as well as low and high costs of rooftop, alpine and ground-mounted.

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[65] Weighted average cost of capital: corresponds to the cost of capital rate/return on capital.

mands on logistics and project management, which can offset the cost benefits.

- **Regulatory framework and the 'Swiss finish':** The regulatory requirements for PV plants in Switzerland are high, particularly when compared to neighbouring countries. Strict guidelines apply to all types of installations, for example regarding earthquake safety, earthing or snow load. These regulations lead to more complex approval procedures and additional construction and safety measures, which are directly reflected in the investment costs.

- **Batteries:** Smaller rooftop plants in particular, but increasingly also larger industrial rooftop plants, are supplemented with batteries for the temporary storage of the solar power generated. This increases the own use of the PV plant. The additional costs of the battery increase the levelised cost of the combined system.

The wide variety of different plant types, possible locations and sizes means the costs and revenues of PV can vary significantly. In this analysis, we distinguish between rooftop PV, ground-mounted PV and alpine PV, and calculate plants with low, medium and high cost assumptions for each. As infrastructure plants, façade PV and agricultural PV involve highly project-specific costs, they are not covered in this section. For rooftop PV, we also distinguish between small, medium and large plants. For rooftop PV plants of under 30 kW and between 30–100 kW, the case of a combined plant with battery storage is also shown as an example.

The costs of PV plants are based on the following assumptions:

CAPEX

The quality and availability of the data used for investment decisions (CAPEX) vary significantly according to the type of photovoltaic plant. For **rooftop plants**, the data in Switzerland is sound as the Swiss Federal Office of Energy (SFOE) conducts an annual survey of the costs of completed PV plants and analyses them by plant size[66]. For rooftop PV plants of under 30 kW, current data from 2025 is available. For the remaining rooftop PV sizes, only the figures for 2024 are available. For the sake of comparability, we use the 2024 figures for all plants, adjusted for long-term cost degression (see below: learning curve and cost trends). However, the updated 2050 figures for rooftop PV plants of under 30 kW are close to the assumed costs of the learning curve.

The data also highlights the increasing economies of scale for larger plants. For rooftop PV plants of up to 30 kW, modules account for only around 16 percent of total costs. A further 16 percent is spent on inverters and additional electronics. Labour and administrative costs, as well as site safety and transport, account for a good two-thirds of total costs. The comparatively high labour costs in Switzerland have a significant impact here. These cost components rise much less sharply in larger plants, meaning that module costs account for a relatively larger share of the total. Consequently, modules account for a good fifth of the total costs in plants with a capacity of 30–100 kW, and more than a quarter in plants with a capacity of over 100 kW. Larger plants are therefore more cost-effective overall.

Our reference assumption, as well as the high and low values, correspond to the median and quantiles of the price monitoring study, i.e. not the most expensive and cheapest plants or offers observed.

The CAPEX assumptions for **battery storage** are also based on the 2024 price monitoring study, supplemented by preliminary results from the SFOE regarding price levels in 2025. The study distinguishes between three battery categories: 0–10 kWh, 10–20kWh and 20–30 kWh, for which the CAPEX in 2025 averages 687 CHF/kWh, 571 CHF/kWh und 510 CHF/kWh. These values are used for the low, medium and high costs as the cost ranges for

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[66] Swiss Federal Office of Energy SFOE, 2024, Photovoltaic market: Price monitoring study

the respective categories are not known. To calculate the key figures shown below, it is assumed that the battery capacity is 1.5 kWh per installed kWp of PV capacity.

For **alpine PV plants**, initial empirical data from projects already completed and estimates of future cost trends are currently available. As these are currently 'first-of-a-kind' plants, the initial investment costs are high. The reported CAPEX figures are based on Axpo's experience and on publicly available information regarding comparable projects. Alpine PV faces several specific cost-related challenges. The location means that transport and installation are logistically demanding, while increased requirements for the substructure resulting from high snow and wind loads further drive up costs. In addition, regulatory requirements, particularly regarding protection against earthquakes, avalanches and severe weather, and the design of substructures and ancillary buildings drive up costs.

Excursus: **Development of rooftop PV prices 2018–2024**

The report "Photovoltaikmarkt: Preisbeobachtungsstudie 2024" [Photovoltaics market: Price observation study] shows the cost developments of rooftop PV plants since 2018: It is striking that prices first fell between 2018–2021 but then rose again until 2023. The price increase can be seen as the result of a unique combination of supply chain disruptions, strong demand growth, higher labour and financing costs and the energy crisis in Europe. Prices fell significantly again in 2024 – roughly to their lowest level in 2020.

There is therefore no clear trend towards a short-term decline in costs that could be reliably projected. However, it can be assumed that the price will continue to normalise in 2025 and be below that of 2024.

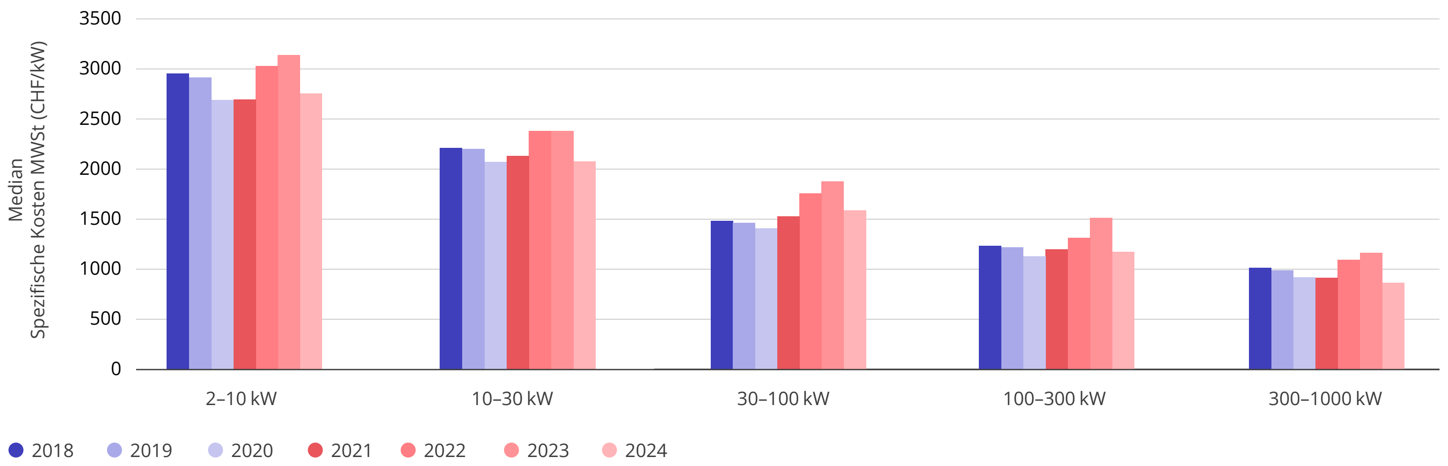

Figure 10: Development of rooftop PV prices 2018–2024

SFOE, Preisbeobachtungsstudie 2024

To date, there is little reliable empirical data available in Switzerland for **ground-mounted PV**. Consequently, the assumptions are currently based on Axpo's internal estimates until a broader empirical data set becomes available. In principle, however, larger ground-mounted plants can be implemented more efficiently as they are easier to install. This leads to lower labour and material costs and enables significant economies of scale.

Grid connection is a key cost factor, regardless of the plant type. The location and the distance to the nearest connection point are particularly decisive. Rooftop PV typically uses existing house or distribution network connections (which may need upgrading). Alpine PV and ground-mounted PV, on the other hand, often require a dedicated grid connection, the fixed costs of which can be spread more effectively across larger, scaled-up plants. These connection costs are included in the respective CAPEX.

OPEX

Various national and international studies on the levelised cost of electricity were evaluated and the respective ratio of CAPEX to OPEX was analysed to determine operating costs (OPEX)[67, 68, 69]. These studies indicate annual OPEX in the region of around 1–2 percent of CAPEX. Against this background, we assume an OPEX of 1.5 percent of CAPEX. For alpine plants, a lower figure of 1 percent of CAPEX is applied as a comparatively large proportion of the investment costs is attributable to long-lasting components such as the substructure.

Full load hours (FLH)

The full load hours assumed here for PV plants are based on Axpo's internal estimates.

Own use

The assumed own use rate of 40 percent for plants of < 30 kW and 50 percent for plants of between 30 and 100 kW is based on analyses by the SFOE from 2025[67]. Battery storage increases the average own use by 20 percent in both cases[70].

Years of operation

The operating period of 30 years is based on Axpo's internal experience and is supported by current studies[71]. For alpine PV plants, a lifespan of 60 years is assumed as the substructure is designed to last 60 years. After 30 years, it is repowered by replacing the PV modules. The costs for this are factored into the CAPEX on a discounted basis. One of the main factors determining the lifespan of batteries is the number of charge and discharge cycles they have undergone. For simplicity, an average lifespan of 15 years is assumed here[72]. As PV plants are designed for 30 years of operation, battery replacement after 15 years is taken into account. For retrofitting, we factor in a corresponding cost reduction plus discounting to the time of investment in the PV plant.

Cost of capital (WACC)

We distinguish between two categories: for smaller rooftop PV plants (under 100 kW) we use a WACC of 3.5 percent, and 4 percent for larger plants. These figures correspond to the cost of capital for general and large-scale PV plants used by the SFOE in its subsidy calcu-

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[67] DETEC, 2025, Federal Act on a Secure Electricity Supply from Renewable Energy Sources Amendment of the Energy Ordinance – Explanatory report
[68] Fraunhofer Institute for Solar Energy Systems ISE, 2025, Photovoltaics Report
[69] Swiss Federal Office of Energy SFOE, 2024, Photovoltaic funding policy and usage strategy of photovoltaic potential
[70] Swissolar, 2025, Battery storage with photovoltaics
[71] Swiss Federal Office of Energy SFOE, 2024, Solar Energy Statistics
[72] Swissolar, 2025, Battery storage

Cost progression of PV plants in 2035 and 2050

		2035								2050							
		Roof < 30 kW		Roof 30–100 kW		Roof > 100 kW		Alpine	Ground-mounted	Roof < 30 kW		Roof 30–100 kW		Roof > 100 kW		Alpine	Ground-mounted
			with battery		with battery		with battery				with battery		with battery		with battery		
CAPEX in million CHF/MW	**Low costs**	1.5	2.9	1.0	2.4	0.7	2.6	2.9	0.6	1.5	2.8	0.9	2.2	0.6	1.9	2.8	0.6
	Reference assumption	1.8	3.0	1.2	2.4	0.8	2.7	4.0	0.8	1.7	2.8	1.1	2.2	0.8	1.8	3.8	0.7
	High costs	2.1	3.1	1.5	2.4	1.1	2.9	5.4	1.0	2.0	3.0	1.4	2.3	1.1	2.0	5.2	0.9
Cost decline vs. 2025		–14%	–17%	–16%	–18%	–19%	–13%	–10%	–20%	–19%	–21%	–21%	–23%	–25%	–25%	–13%	–27%

Table 5: Cost development of various PV plants with commissioning in 2035 and 2050. Showing the reference assumption as well as low and high costs of rooftop, alpine and ground-mounted.

lations[73]. To determine the WACC, the consultancy firm IFBC carries out a detailed analysis specifically for Switzerland. To this end, experts and companies in the sector in Switzerland whose main activity is electricity generation are surveyed[74]. Based on this expert feedback, the SFOE determines the cost of equity and derives the weighted average cost of capital (WACC) from this.

Learning curve and cost trends

To determine cost degression, a separate degression assumption up to 2050 is made for each CAPEX category (labour and administrative costs, modules, inverters and electrical components, as well as site security and transport). The current cost shares of these categories is then used to derive the aggregate cost reduction for the various types of PV plant. For module costs, a learning curve of 25 percent per doubling of global capacity is derived from empirical data in the literature. This results in a reduction of 55 percent by 2050[75]. A cost reduction of 20 percent is assumed for inverters and electrical components. The evidence regarding labour, transport and site safety costs is less clear. Here, a reduction of 10 percent by 2050 is assumed.

Table 5 shows the resulting CAPEX for the years 2035 and 2050 by plant type. It is clear that the higher the proportion of modules in the CAPEX, the greater the economies of scale. Accordingly, the economies of scale are more pronounced in larger PV plants than in smaller ones as the relative cost share of the modules increases as the size of the plant increases, as described above.

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[73] DETEC, 2025, Federal Act on a Secure Electricity Supply from Renewable Energy Sources Amendment of the Energy Ordinance – Explanatory report

[74] In the absence of empirical data, this survey is the best available proxy for deriving the WACC. In theory, it would be derived from the correlation between the overall market return and the share returns of several technology-specific operators. To calculate the WACC for ground-mounted PV plants, the share returns of several operators specialising exclusively in ground-mounted PV plants in Switzerland would be needed; however, such operators do not exist.

[75] International Energy Agency IEA, 2024, Trends in Photovoltaics Applications. The IEA expects a price reduction of around 25 percent for each doubling of the globally installed PV capacity.

Feed-in limit

As described in Section 2.6, the feed-in capacity of PV plants can be specifically limited in order to protect the grid from overloading and ensure stability. This leads to a reduction in revenue; however, the loss of revenue mainly occurs during periods of very high solar power generation, when electricity market prices are typically particularly low (see Section 5.1.3). For example, if the feed-in capacity is limited to 70 percent, only around 3 percent of the annual production is lost, whereas if the feed-in capacity is limited to 50 percent, just under 20 percent is lost.[76] Depending on the technical implementation (restriction at the connection point, e.g. via an EMS, or at the inverter), the energy remains available for own use[77]. The effects of feed-in limits are not taken into account here.

Where do electricity prices come from?

Nobody knows the future price of electricity. To gain insight into the question, we work with different scenarios, outlines a possible direction in which the markets might develop. As a rule, fundamental models are used for the long-term perspective – they are not based on historical data, but explicitly map future power plants and load development and simulate today's market mechanisms and pricing. Since we do not know the future, we work with different scenarios and estimate a range of possible developments, prices and thus also revenue.

Our fundamental model simulates the electricity market of European countries, including Switzerland, for the period 2025–2060. The development of renewable energies, demand, cross-border import and export opportunities and other important market factors such as future prices for gas and CO_2 $_{\text{emissions}}$ are taken into account. This can be used to derive hour-by-hour future price scenarios, as well as power plant operations and hourly imports and exports per country.

Two scenarios are considered for other European countries. From this, we determine a range of possible revenues. The average revenue is the average of the results. The two scenarios differed as follows:

- In the first scenario, decarbonisation of the global economy makes progress, but is not yet fully achieved. The electricity sector in Europe will achieve 90 percent decarbonisation by 2050. Thermal power plants will serve as a backup. Carbon capture and storage and hydrogen will be used, but only to a limited extent. Electricity demand will grow moderately.

- In the second scenario, global climate policy adopts a new pragmatism and will achieve 80 percent decarbonisation by 2050. Renewable energies will dominate power generation; gas will be the most important backup power source. Electricity demand will rise less than in scenario 1, due to lower demand from hydrogen electrolysis.

For Switzerland, a net zero scenario is assumed in which decarbonisation increases demand; for gas-fired power plants, various decarbonisation options are available. Details can be found in the Gas Report and the Synthesis Report.

The prices for gas, CO_2 emissions and other primary energy sources are based on the Announced Pledges (AP) and Stated Policies (SP) of IEA's World Energy Outlook.

Validation was carried out in a study together with the FEN Research Center for Energy Networks at ETH Zurich.

[76] Bucher, 2025, Incentives for system-friendly network connection of photovoltaic plants, implementation proposal to relieve the burden on distribution networks

[77] VSE, 2025, Industry recommendation

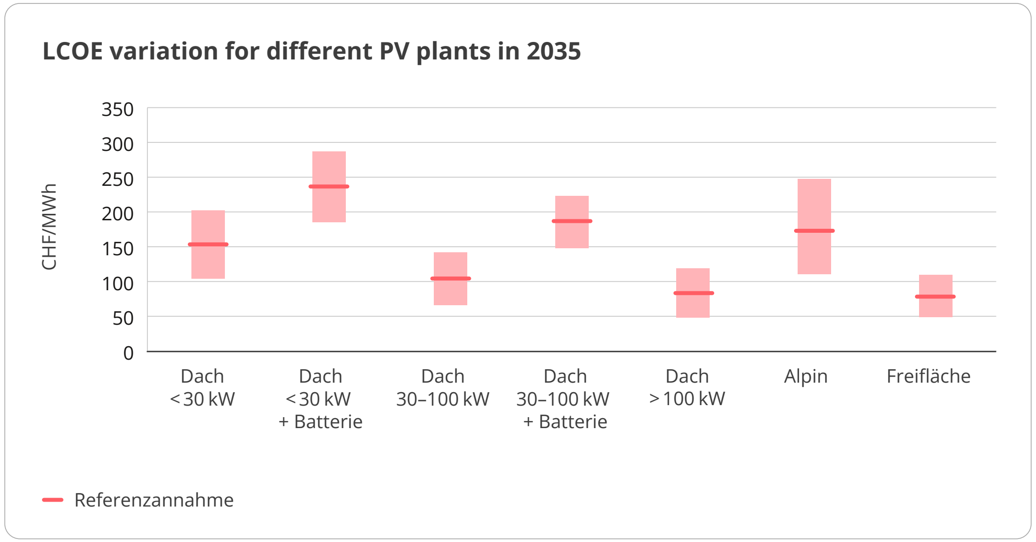

Figure 11: Range of levelized cost of electricity (LCOE) for different PV installations in 2025. The orange lines show the costs under reference assumptions, while the lower and upper limits of the bars are determined by low and high cost scenarios.

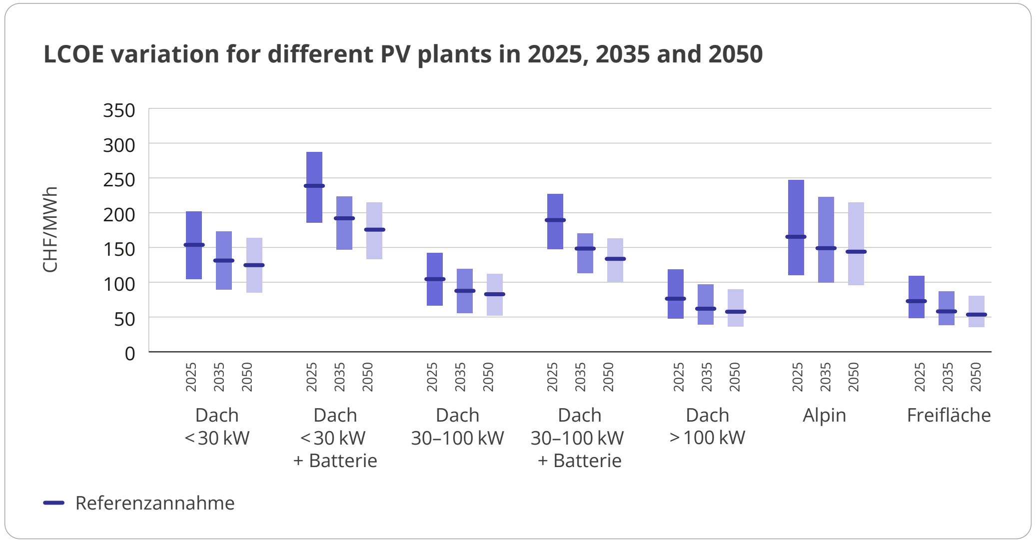

Figure 12: Development of levelized cost of electricity for different types of PV installations for the years 2025, 2035, and 2050. The blue lines show the costs under reference assumptions, while the lower and upper limits of the bars are determined by low and high cost scenarios.

5.1.2
Levelised cost of electricity

The LCOE resulting from the cost assumptions in 2025 are shown in Figure 11.

Small-scale rooftop plants benefit only to a limited extent from economies of scale and lower module costs as the proportion of fixed costs for planning, installation and management is comparatively high. As a result, their levelised cost of electricity is significantly higher than that of other types of plant and is, as a rule, two to three times higher than that of ground-mounted plants. Large rooftop plants are increasingly able to achieve economies of scale. As the size of the plant increases, the specific costs fall, so their levelised cost of electricity gradually approaches that of ground-mounted plants. Ground-mounted plants generally have the lowest levelised cost of electricity. This is primarily due to simple installation, standardised processes and significant economies of scale. In Switzerland, however, such plants are challenging due to regulatory frameworks. Alpine PV plants, on the other hand, are associated with high levelised costs of electricity. The reasons for this are the complex logistics, installation, expensive grid connection in difficult terrain, and increased material and construction costs, particularly for robust substructures that must withstand heavy snow loads. The addition of a battery increases the levelised cost of the combined system.

The learning curve described above is assumed for cost trends in 2035 and 2050. By 2050, costs for rooftop plants will fall by between 19 percent and 25 percent depending on the PV type, by 27 percent for ground-mounted plants and by 13 percent for alpine plants. Rooftop PV plants of under 30 kW and alpine PV plants continue to have the highest levelised costs, while larger rooftop PV plants of over 100 kW and ground-mounted plants remain the most cost-effective in 2050 due to economies of scale.

5.1.3
Market revenue

The market revenue generated by a photovoltaic plant is determined by the electricity price achieved on the market. Detailed Europe-wide fundamental market simulations were carried out in order to calculate future electricity prices (see info box p. 44).

During sunny hours, electricity prices on the market are often low. The reason for this is the already high level of electricity generation from photovoltaic plants, which leads to a large simultaneous supply of electricity and has a dampening effect on prices as a result. As PV penetration continues to rise, the supply of electricity during these hours increases further, putting additional pressure on market prices and reducing the achievable revenues. This effect is referred to as cannibalisation.

In Switzerland, it should be noted that cannibalisation does not depend solely on domestic PV penetration but is significantly influenced by developments in neighbouring countries. This is due to the Swiss electricity system's strong interconnection with other countries, as well as the relatively low volume of electricity generation and demand compared to neighbouring countries. Pronounced cannibalisation, such as that already observed in Germany today, therefore also spills over into the Swiss market. Conversely, surplus Swiss solar power can, in principle, be absorbed without difficulty by the significantly larger neighbouring countries, thereby mitigating domestic cannibalisation, provided there is no simultaneous surplus of production in those countries.

If PV feed-in exceeds electricity demand and cannot be curtailed, this may lead to negative prices. If the regulatory framework is designed such that feed-in is remunerated even at negative prices, e.g. through a minimum remuneration or a fixed feed-in remuneration, then the plants will continue to operate even in the event of a generation surplus, thereby triggering negative prices. Without this regulatory requirement, controllable PV plants would be curtailed. However, the majority of negative prices in Switzerland over the coming years will be driven by the price structure from abroad, in particular by negative prices from Germany.

Revenue from guarantees of origin (GoOs)

Since the introduction of the fuel mix disclosure in 2009, a guarantee of origin (GoO) has been issued for every kWh of electricity produced. The GoO is a certificate that shows the origin and any quality characteristics (e.g. electricity from renewables). The certificates are traded independently, decoupled from the physical flow of electricity. All PV plants receive the same GoO, regardless of the plant type.

Unlike the obligation to purchase and pay for electricity pursuant to Article 15 of the Energy Act, grid operators are not obliged to purchase the GoOs for installations with a capacity of less than 150 kW. However, most grid operators in Switzerland voluntarily remunerate the GoO for the electricity fed in from these plants. Larger plants sell their certificates on the market. To enable comparability between the different plant types, the market value of the GoO for PV is used here. This is currently estimated by the SFOE to be 0.5 cents/kWh.[78]

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[78] DETEC, 2025, Federal Act on a Secure Electricity Supply from Renewable Energy Sources Amendment of the Energy Ordinance – Explanatory report

Market revenue of PV plants

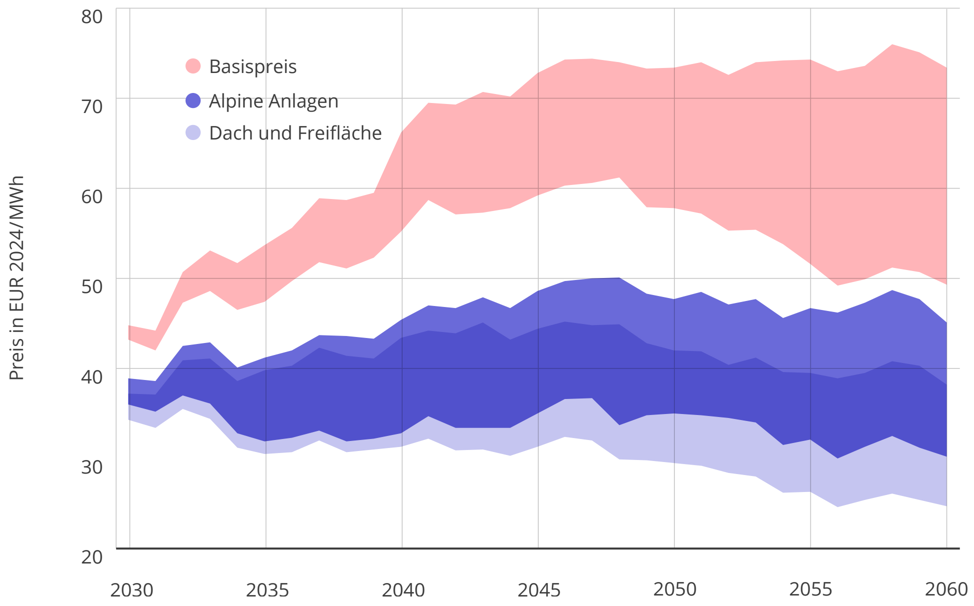


Figure 13: Market revenue from alpine and non-alpine photovoltaic plants and base price (average annual price)

The resulting revenue is shown in Figure 13. The aforementioned cannibalisation causes revenues from PV plants to be below the base price, i.e. the annual average of electricity prices. The annual market prices achieved for PV plants in the 2030s range between 30 and 40 CHF/MWh and rise to levels above 40 CHF/MWh in the 2040s, before falling slightly again towards the end of the 2040s. Alpine PV plants are increasingly able to command higher market prices than rooftop and ground-mounted plants in lower-altitude locations due to their higher proportion of electricity generated in winter. Even PV plants with less temporal overlap with the rest of the PV generation – for example, due to an east or west orientation – tend to generate higher revenue as their output increasingly occurs during periods of lower supply, particularly during the off-peak hours in the morning and evening.

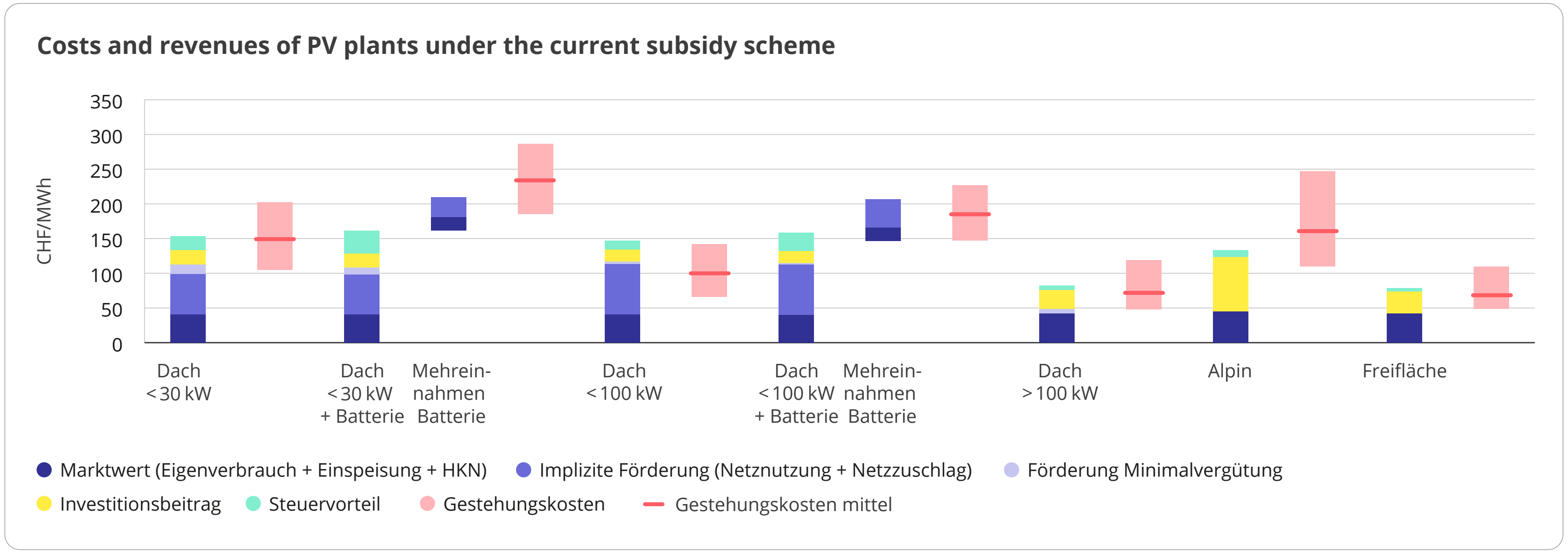
If a battery storage system is added to the PV plant, the market revenue of the combined system change significantly. During hours of high solar production, electricity prices are typically low, as described above. If the solar power generated can be temporarily stored and then consumed by the user or fed into the grid at a later time when prices are higher, the average market price achieved increases. The market value of a PV plant with battery storage is therefore higher than that of a comparable plant without storage. Furthermore, the battery storage system can generate additional revenue through arbitrage, provided spare capacity is available. Arbitrage refers to the storage system drawing electricity from the grid during low-price hours, regardless of its own PV production, and feeding it back into the grid during high-price hours. The extent to which arbitrage is possible depends primarily on the ratio of battery capacity to PV output. In addition, either the price dynamics must be passed on to the customer (e.g. via dynamic tariffs) or the battery must be bundled with other plants, such as in a virtual power plant, so that trading and optimisation can be implemented effectively.

The market value of the battery storage system is therefore derived from the combination of revenue shifting (time-shifting) and arbitrage potential, both of which are largely determined by the daily maximum price spread. The 2-hour price spread currently stands at just over 50 CHF/MWh and is set to fall to below 45 CHF/MWh by 2035. It will then rise significantly to over 65 CHF/MWh by 2045, before showing a slight downward trend until 2060.

Battery storage systems can also supply or absorb balancing power (when activated to correct deviations from the schedule). Today, uncertainty in feed-in forecasts increases the demand for balancing energy. In future, greater flexibility, better forecasts and an adapted market design are likely to reduce these inefficiencies.

5.2
Economic viability under current regulations

In the following, we analyse the economic viability of PV plants under the current regulations and market conditions.



Costs and revenues of PV plants under the current subsidy scheme

Figure 14: Comparison of income and costs for different PV plants commissioned in 2025.

From the perspective of a rational investor, Figure 14 compares the production costs with the various sources of income (incl. subsidies) for different PV plant types. The results show that investments in PV plants today are in many cases economical from an investor's perspective. For almost all PV types considered, the expected revenue including subsidies exceeds the average production costs – with the exception of some battery storage systems and some alpine PV plants.[79] Large rooftop PV plants with own use and ground-mounted PV plants are particularly lucrative. Own use plays a key role in the economic viability of rooftop PV plants, particularly for smaller plants. The key factor here is the implicit subsidy through reduced grid cost contribution with own use, which significantly increases revenues. Given the assumptions made here, if PV plants are combined with battery storage, this raises costs more than it boosts revenue. Thus, investments in battery storage are often not economical for investors under the assumptions made here. (Nevertheless, around half of all smaller rooftop PV plants are now built with battery storage; see explanation in the box "Background: Battery storage despite a lack of profitability for investors?").

[79] Individual projects may deviate from the assumptions made here. For example, there have been cases of PPAs that were above the expected fair value for alpine PVs in which revenues exceeded those shown here.

The revenue is comprised of:

Fair value of PV and GOs

The market revenue of a photovoltaic plant is determined by the electricity price achieved on the market, which is known as the "capture price" (see section 5.1.3 Market revenue). This applies to both the electricity consumed and the electricity fed into the grid. We are therefore assuming a dynamic energy tariff that passes on price signals from the electricity market to end customers. In addition, revenue from certificates of origin, which is usually paid by the energy supplier, must be taken into account. As described in section 5.1.3, a GO value of 0.25 cents / kWh[80] is used for all plant types. The actual payment from the energy supplier may be higher. As described above, revenue from balancing power is not taken into account.

Revenue from various different PV plants in 2025

	Roof < 30 kW		Roof < 100 kW		Roof > 100 kW	Alpine	Ground-mounted
CHF / MWh		With battery		With battery			
Non-recurrent remuneration	21	21	17	17	27	78	32
Minimum remuneration	14	9	4	2	5	0	0
Tax benefit	20	33	13	26	7	10	5
Implicit subsidy	58	87	72	101	0	0	0
Market revenue (incl. GO)	41	59	41	59	42	45	42
% of production costs covered by implicit subsidy	38%	36%	69%	53%	0%	0%	0%

Table 6: Comparison of the revenue streams of different PV plants in 2025.

Implicit subsidy through reduced grid cost contributions

PV plants do not have to pay grid connection and usage charges for the PV electricity they consume themselves (see section 4.2) and are therefore implicitly subsidised in this respect as well. In the current tariff design for customers in the basic supply, this corresponds to around half of the electricity tariff – an average of 14.5 out of 29 cents / kWh[81] in 2025 – and consists of the grid usage fee and grid surcharge. Savings on municipal charges are not taken into account here, but would also represent avoided costs. Other implicit subsidies such as the LEG discount are likewise not considered here. However, they do tend to represent additional income for small systems.

Investment subsidy

The subsidies are comprised of the non-recurrent remuneration and the minimum remuneration (see section 4.1 Current subsidies). The amounts for the investment subsidies for the different PV types are based either on the non-recurrent remuneration rates or, for installations larger than 150 kW, on the results of the high non-recurrent remuneration auction (Pronovo AG, 2025). Due to the currently low level of participation in the sliding feed-in premium system, only the non-recurrent remuneration auction is used

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[80] Reference scenario; scenario high uses 0.50 cents / kWh, scenario low uses 0.00 cents / kWh.
[81] ElCom, 2025, Swiss electricity prices

at this point. Potential finding bonuses are being overlooked. For alpine solar energy systems, a subsidy amounting to 60 percent of the investment cost is applied.

Minimum remuneration subsidy

To calculate the additional revenue resulting from the minimum remuneration, the difference between the quarterly capture prices and the minimum remuneration is determined each quarter.

Tax benefit

Like other technologies, PV plants also benefit from tax relief (depreciation or tax deductions). We assume that this amounts to 20 percent of investment costs after deduction of the investment subsidies [82, 83]. For the sake of comparability, the tax benefit is assumed to be the same across the board for all PV types under consideration. However, it is still unclear whether rooftop PV will still be tax–advantaged after the loss of the imputed rental value. Additional costs in the form of profit taxes are not considered here.

Battery storage

Upgrading a PV plant with a battery storage system increases the market revenue of the combined system by allowing producers to store the generated power temporarily and then either use it themselves or feed it into the grid at a later point in time when prices are higher (see section 5.1.3 Market revenue). This also increases own use, which can further reduce the grid cost contribution. However, as less PV electricity is fed into the grid, revenue from the minimum remuneration and GO is accordingly lower.

These revenues are shown on a sales-weighted basis, which means, for example, that guarantees of origin are only counted for the electricity that is fed in (example calculation for roof PV < 30 kW: CHF 2.50 / MWh GO * (1–40 percent own use) = CHF 1.50 / MWh). The overview shows that a large part of the revenue from rooftop PV is attributable to the implicit subsidisation of own use[84] – up to 69 percent for rooftop PV < 100 kW without battery storage. Larger roof systems without own use or ground-mounted and alpine PV plants do not enjoy this advantage. If an adjustment to the tariff design – for example through increased fixed costs – were (in part) to eliminate the implicit subsidy for own use, this would significantly reduce the profitability of systems with own use.

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[82] Swissolar, cantonal and federal tax practices

[83] Swiss Federal Office of Energy SFOE, 2024, Photovoltaic funding policy and usage strategy of photovoltaic potential

[84] Schröder, C., 2025, Integration of future PV expansion into the energy system

Background: **Battery storage despite a lack of profitability for investors?**

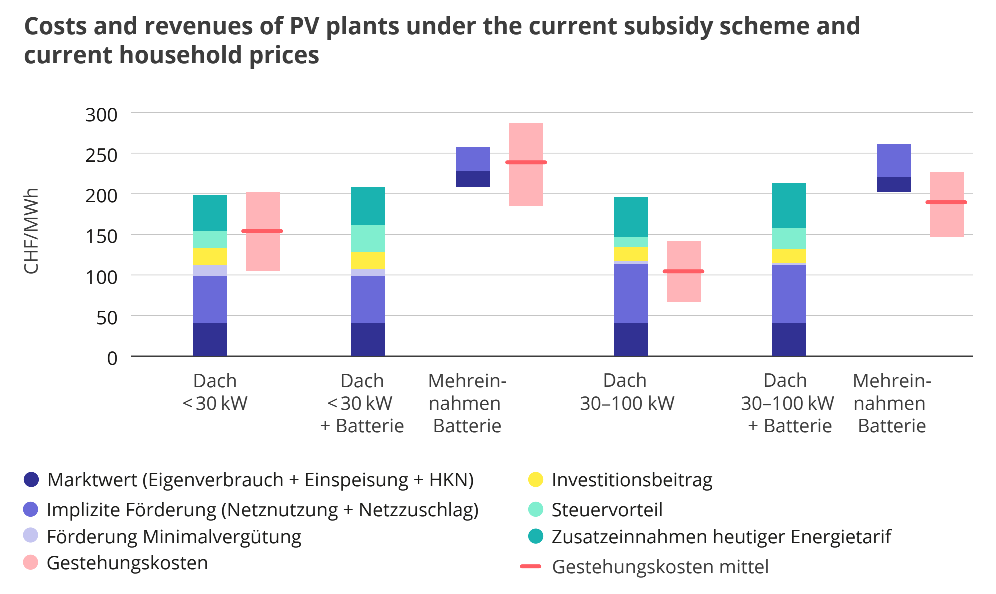

Figure 15: Comparison of income and costs for different PV plants commissioned in 2025. In yellow: Savings through own use taking into account the current energy tariff.

Under the assumptions made here, smaller PV plants with battery storage are, despite the subsidies, seldom economically viable from an investor's point of view. Nevertheless, around half of all smaller rooftop PV plants are now built with battery storage. This apparent paradox can primarily be explained by different assumptions about the development of retail tariffs.

One important factor here is that investment decisions are often made on the basis of current or historical retail tariffs. The Swiss average energy tariff for customer group H4 (typical household with higher electricity consumption) is 12.1 cents/kWh in 2026 (2025: 13.7 cents/kWh)[85] and thus well above the assumptions about the long-term development of electricity market prices used in this analysis. Based on the current price level, our market models assume that electricity market prices will continue to fall, with an average market price of around 4 cents/kWh through 2050.

However, there are several reasons why energy tariffs are likely to fall again compared to today's levels: the energy tariff reflects the average electricity procurement costs of energy suppliers. They either procure their electricity on the market or generate it in their own plants; the latter is valued at cost, which is largely stable over time. The current tariff is still heavily influenced by the price distortions on the electricity markets during the 2022/23 energy crisis. Before the energy crisis, the average energy tariff throughout Switzerland was significantly lower, at around 7 cents/kWh.

Figure 15 shows the profitability calculation if the fixed 2026 energy tariff of customer group H4 is used as the basis for calculation for the entire service life of the PV plant. This increases the revenues for own use of the PV plant, as the fixed energy tariff is saved rather than the market price (shown in yellow on the left). The electricity fed into the grid continues to be remunerated at fair value, taking the minimum remuneration into account. Under these assumptions, it is clear that PV plants with battery storage are economical from an investor's point of view in times of high energy tariffs, as they reduce the amount of electricity consumed at these high cost levels.

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[85] ElCom, 2025, Swiss electricity prices

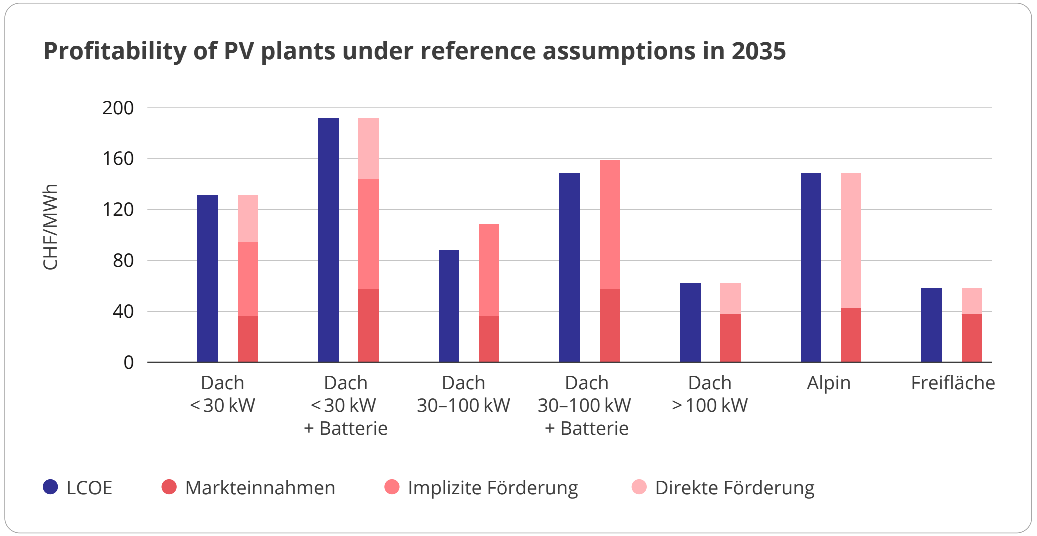

Figure 16: Profitability of PV plants under reference assumptions in 2035

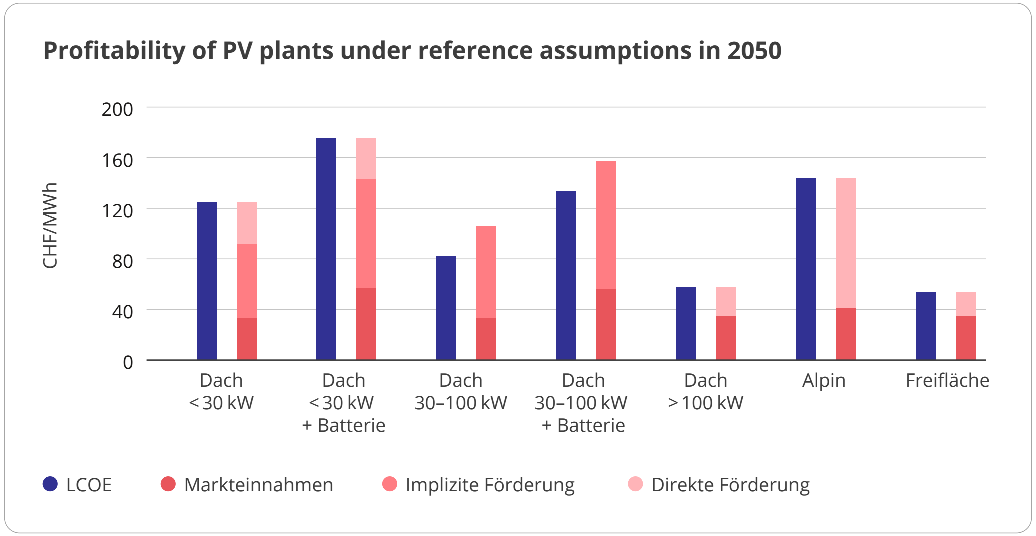

Figure 17: Profitability of PV plants under reference assumptions in 2050

5.3

Development of subsidy requirements in 2035 and 2050

Looking ahead to 2035, the cost and revenue structures will change. Costs will fall due to the assumed economies of scale for PV plants, while the average market revenues over the lifetime of new systems in 2035 will remain roughly at the level of new systems in 2025. We disregard the current subsidies and show the subsidy requirements instead. The subsidy requirement is defined as the difference between average electricity generation costs and market revenue, supplemented by implicit subsidy from reduced grid cost contributions for rooftop PV.

Figure 16 shows that, under the aforementioned assumptions, none of the systems considered will be able to cover their costs solely from market revenue in 2035. As is currently the case with all other electricity production technologies in Switzerland, government subsidies are therefore indispensable for the economic viability of PV plants. Due to the falling costs and continuing high revenue from implicit subsidisation of own use, rooftop PV plants between 30 and 100 kW do not require subsidies. The subsidy requirement is lowest for ground-mounted systems (and large rooftop PV plants) – more than 60 percent of the costs are generated on the market. For rooftop PV < 30 kW, only around 30 percent of the costs can be covered by market revenue; the rest must be financed through implicit subsidisation (reduced grid cost contribution, 45 percent) and subsidies (investment subsidies, minimum remuneration, 25 percent). Alpine PV continues to have a very high need for subsidies due to high specific costs.

It is unclear whether the implicit subsidy remains in place in 2035. In the event of tariff changes (e.g. dynamic grid tariffs), this implicit subsidy could be partially or completely eliminated. The direct subsidy requirement would increase accordingly.

The pattern for 2050 is similar to that of 2035. The cost level is declining overall, but market revenues remain more or less constant. Result: the subsidy requirement will be reduced for all PV types without the fundamental dependence on subsidies being completely eliminated (except for rooftop PV 30–100 kW).

5.4

Subsidy requirements for the winter half-year

In addition to the fundamental economic viability, the Axpo Energy Report is particularly interested in the meaningful contribution a technology can make to the electricity supply in the winter half-year. The decisive factor here is how subsidy-dependent a technology is for the electricity generated in the winter half-year.

Figures 18 and 19 show the subsidy requirements for winter power generation in 2035 and 2050. The subsidy requirements shown in the previous section are allocated to winter power generation – this amounts to 27 percent for rooftop PV, 30 percent for ground-mounted PV and 45 percent for alpine PV. Also shown is how much the subsidy requirement would increase if the implicit subsidy for own use were eliminated due to tariff changes.

Winter power generation can vary considerably depending on the type of system and accordingly influences the subsidy require-

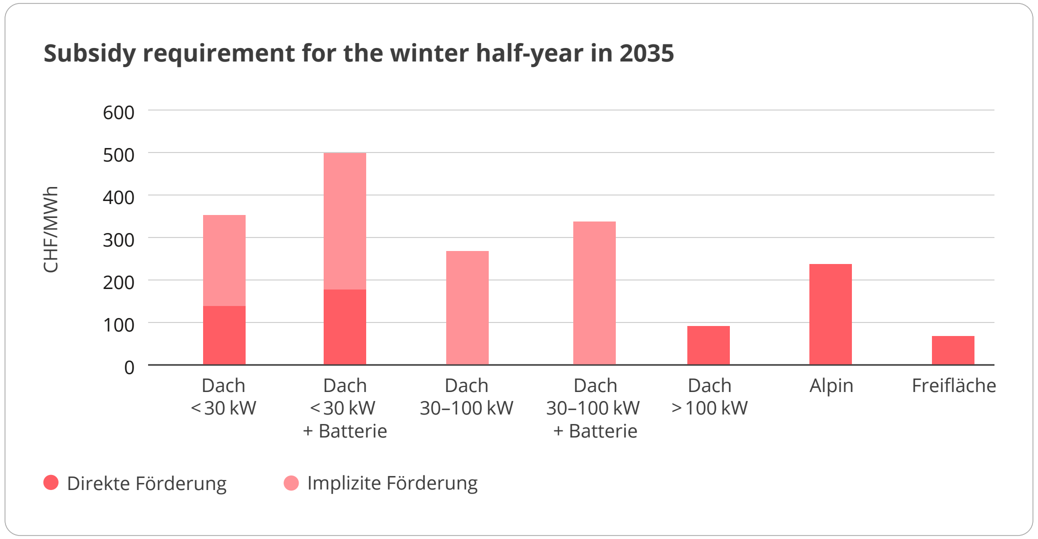

Figure 18: Subsidy requirement of PV plants based on reference assumption in 2035, where the required subsidies are distributed across the amount of electricity produced in winter.

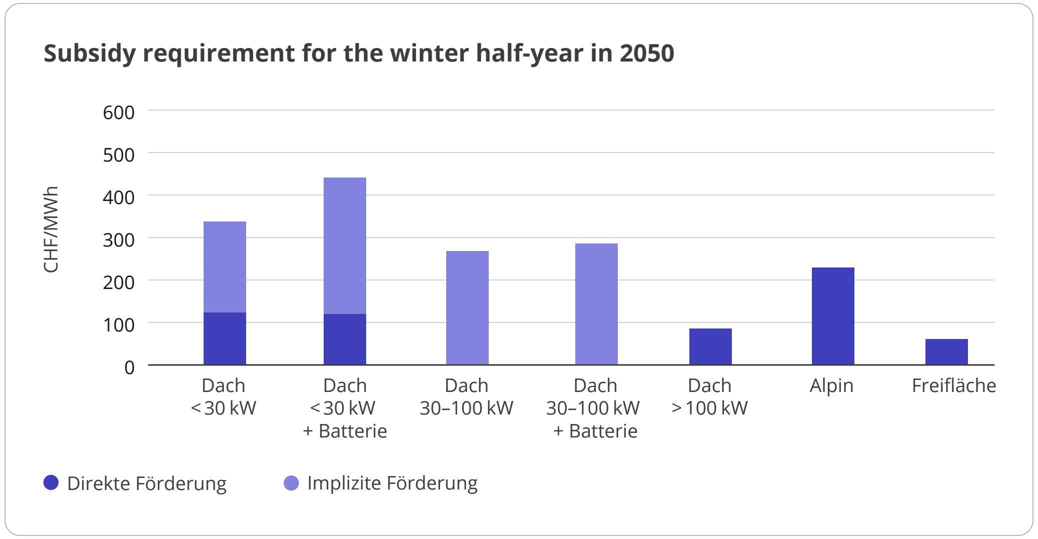

Figure 19: Subsidy requirement of PV plants based on reference assumption in 2050, where the required subsidies are distributed across the amount of electricity produced in winter.

ment per MWh in the winter half-year. Systems with higher winter electricity generation require lower specific incentives per MWh in the winter half-year. A good example here is ground-mounted systems, which can generate an increased share of winter electricity even outside the alpine region, given sufficient elevation, thanks to their significantly higher winter electricity production. Another example is east/west-facing PV plants, which, thanks to their generation characteristics, produce more uniform electricity throughout the day, particularly in the winter half-year, thus increasing the usable winter electricity.

Depending on the type of PV, the subsidy requirement for winter electricity ranges between CHF 0 and over CHF 200/MWh. Rooftop PV 30–100 kW has no subsidy requirement and therefore requires no subsidies for winter electricity. Despite higher winter electricity generation, alpine PV has the highest winter subsidy requirement due to high electricity generation costs.

Without the implicit subsidy for own use, the picture shifts considerably. Rooftop PV would then be between CHF 270 and 500/MWh, which is higher than alpine PV. In this case, large roof plants and ground-mounted PV would have the lowest winter subsidy requirement at around CHF 70–100/MWh.

A similar picture emerges for 2050. The low subsidy requirement for the systems with batteries is notable, but only if the implicit subsidy through reduced grid cost contributions remains in place.

06

Value creation and employment

Rooftop PV plants have a domestic value-added share of 75 percent and create approximately 650 full-time jobs per TWh

In brief

- Most of the expenditures remain in Switzerland; the main investments flowing to other countries are for electronic components (modules, inverters), which account for only around 17 percent of the total costs.
- Over its entire lifetime, the domestic value added of a rooftop PV plant in Switzerland is around 75 percent of the total cost.
- Investments in rooftop PV plants create around 650 full-time equivalents per TWh.

6.1
Value chain

The value chain for rooftop PV plants can be split up into planning, financing, manufacturing, construction/installation and operation (see Table 7). For each of these steps, the respective share of costs can be recorded and split up into domestic and imported shares: Planning, financing, construction/installation and operation take place predominantly in Switzerland and account for 83 percent of the costs. The production of key components, such as modules and inverters, primarily takes place abroad and accounts for 17 percent of the costs. Throughout the entire service life, 84 percent of the total costs are incurred in Switzerland. The costs of dismantling, disposal and recycling are taken into account in the investments and thus in the manufacture of the components[86].

When it comes to the value-added stage of manufacturing, there is considerable dependence on foreign countries. A significant share of the modules and solar cells as well as numerous electrical components, such as inverters, are produced predominantly in China.

Methodological note

The macroeconomic aspects of the generation technologies considered in the Axpo Energy Reports were analysed and processed by Swiss Economics. For detailed information, please refer to the analysis, available separately.

For the analysis, we examine a rooftop PV plant with an installed capacity of around 10 kW and an annual output of around 10 MWh as a reference. The costs of this investment correspond to the assumptions described in section 5. In order to keep the presentation of value-added effects as clear as possible, other types of installations – in particular ground-mounted installations and alpine PV plants – were not used. These plant types have similar value chains, but have different cost allocations.

6.2
Value creation from rooftop PV plants in Switzerland

To calculate domestic value added, all costs incurred within Switzerland are assigned a suitable multiplier based on the stage of the value chain. This makes it possible to determine how much value is created from an expenditure. The multiplier subtracts the expected foreign inputs of a company in the respective sector. Depending on how many foreign inputs are needed in a sector, more or less domestic added value is generated for the same amount of Swiss francs. For a new rooftop PV plant in Switzerland, a domestic value-added share of around 75 percent of the total costs is generated over its entire operating period.

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[86] A domestic share equal to the manufacturing share is used for this purpose. In the future, however, recycling could increasingly take place domestically.

Value chain

	Planning	Financing	Production	Construction/installation	Operation
Value-added steps	🔵 Planning 🔵 Engineering 🔵 Feasibility and environmental studies	🔵 Financing (equity and debt) 🔵 Depreciation and amortization	🔴 Modules 🔴 Inverters 🔴 Installation material	🔵 Transport 🔵 Installation 🔵 Grid connection	🔵 Inspection rounds 🔵 Metering 🔵 Inverter replacement 🔵 Insurance
Cost share	3%	56%	17%	19%	5%
of which national	92%	99%	26%	94%	71%
Provider	Predominantly Swiss engineers and planning offices, operators	Financing by Swiss banks and operators (50:50%)	Specialist European providers, first Swiss providers with a low market share	Local solar and electrical installers	Maintenance, operation and marketing by operator, repairs by Swiss companies, spare parts from abroad, low energy share
Significant dependencies abroad			Modules and solar cell inverter production mainly in China, wafer production mainly in China		Most spare parts from China

🔵 Local 🔴 Foreign

Table 7: The value chain and associated cost breakdowns (Switzerland/abroad) for rooftop PV plants in Switzerland.

ZHAW (2017), Huemer (2016), Hirschl (2010), SFOE (2020), IEA (2021), IEA (2021), pv-barometer.ch (2025), Solaranlage-ratgeber.de (2025), SFOE (2025)

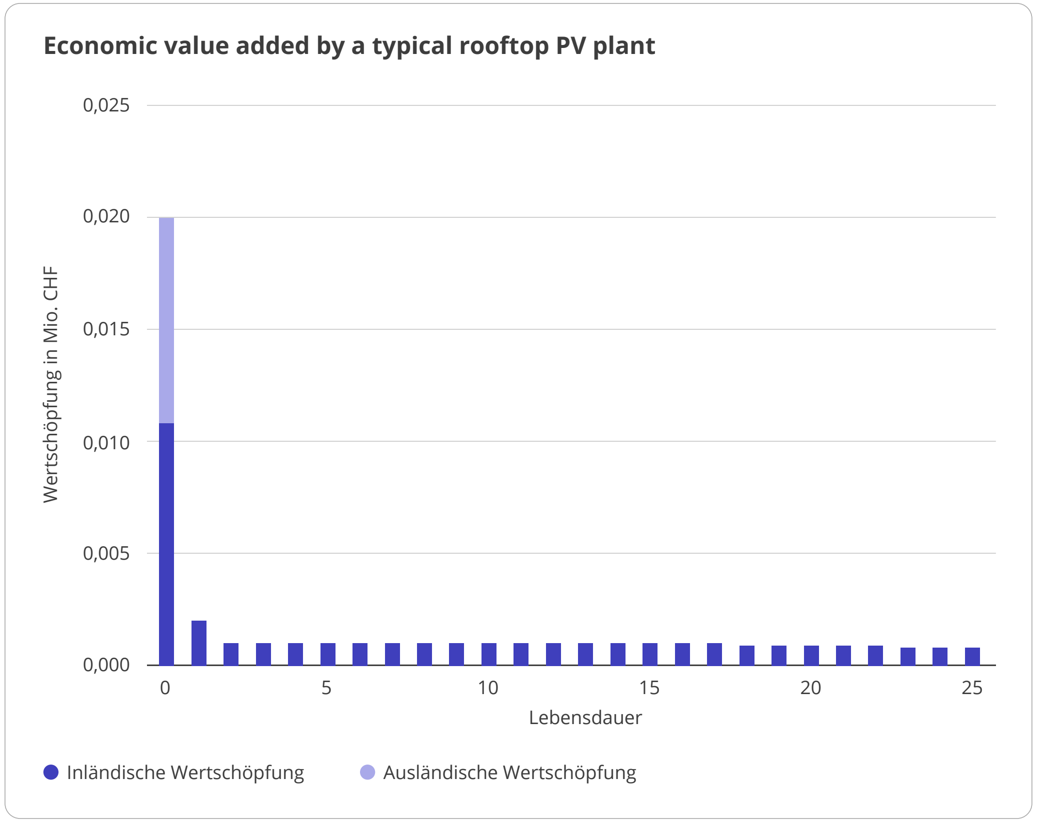

Figure 20: Value creation of a typical rooftop PV plant seen over 25 years, divided into domestic and foreign shares.

As shown in Figure 20, value creation is spread over different phases of the system's life cycle. To put it simply, it is assumed that all expenditures for planning, manufacturing the power plant components, construction and installation are incurred in the one-year construction phase. This is followed by the operational phase for the life of the system, during which the operating and financing costs (capital costs and depreciation) are incurred. The added value is unevenly distributed over the service life. The high value creation in the first year is followed by lower value creation in subsequent years while the system is in operation. For the rooftop PV reference system with an installed capacity of 10 kW, assumed total costs of 50 000 CHF would result in a domestic value added of 36 500 CHF – broken down into 9 100 CHF for construction and 27 400 CHF for operation.[87]

Value creation and subsidies

Government subsidies typically cover a significant proportion of electricity generation costs in Switzerland. If the necessary subsidies are subtracted from the reported value added, the actual market-driven share of value added is correspondingly lower.

In other words: a significant part of value creation is made possible only by government support. If the corresponding subsidies are deducted from the value added, the domestic value added of the reference investment under consideration is reduced by around 36 500. CHF to 13 500 billion. The share of domestic value added in the total costs then falls from 75 percent to 28 percent.

[87] The domestic value added by PV is comparable to the turnover values of the Swiss solar industry as reported by Swissolar (CHF 2.8 billion in 2024)

6.3
Employment from rooftop PV plants in Switzerland

Investments in rooftop PV plants create jobs, measured in full-time equivalents (FTEs), which are needed over the entire life cycle of the system. A reference rooftop PV plant in Switzerland generates a total of around 0.16 FTEs per year over its lifetime, which corresponds to 646 FTEs per TWh. Employment is unevenly distributed across construction and operations. During the one-year construction phase, an average of 0.07 FTEs are required per year, while operations require 0.004 FTEs per year. Or converted to a TWh basis, around 6900 FTEs for construction and around 370 FTEs per year for operations.[88]

6.4
Impact of batteries

As described in section 2.5, rooftop PV plants in Switzerland are increasingly being installed together with batteries. As with PV, the value added from manufacturing the components is predominantly abroad, while the remaining stages of the value chain tend to be produced domestically. However, since the share of manufacturing costs, at 34 percent of total costs, is higher than for PV at 17 percent, more of the spending on battery storage goes abroad.

A PV plant with a battery therefore also has different effects on value creation and employment than a PV plant without a battery. The exact impact depends on how large and expensive the battery is compared to the PV plant. If a reference rooftop PV plant also has an integrated battery in line with the assumptions in section 5.2 (here, for example, 13.5 kWh), the domestic value added of the overall system increases by 8.3 to a total of CHF 44 800.

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[88] These employment figures are comparable with the demand for skilled workers in the PV sector according to Swissolar (around 10 600 FTEs for the installation of 1.8 GW in 2024).

Impact of batteries on the value chain

	Planning	**Financing**	**Production**	**Construction/installation**	**Operation**
Value-added stage	🔵 Planning	🔵 Financing (equity and debt) 🔵 Depreciation and amortization	🔴 Battery modules and BMS 🔴 Inverters 🔴 Balance of system	🔵 Transport 🔵 Installation	🔵 Energy losses 🔵 Maintenance 🔵 Spare parts 🔵 Insurance
Cost share	2%	39%	34%	6%	19%
of which national	95%	99%	8%	80%	72%
Provider	Planning by Swiss installers and operators	Financing by Swiss banks and operators (50:50%)	Electronic components mainly from abroad	Local installers	Maintenance and operation by Swiss operators, spare parts from abroad, energy from Switzerland
Significant dependencies abroad			Manufacture of battery modules and inverters mainly in China		

🔵 Local 🔴 Abroad

Table 8: Value chain and the associated Swiss/foreign cost shares of home storage in Switzerland.

NREL (2024), Highjoule.com (2025), SFOE (2025)

07

Environmental impact

Ground-mounted PV has higher land requirements and more hazardous waste than other technologies, but produces little greenhouse gas emissions and radioactive waste.

Methodological Note

The environmental impacts of the generation technologies examined were analyzed and processed by the Paul Scherrer Institute (PSI). For detailed information, please refer to the separately available analysis. The environmental impacts are calculated using life cycle assessment (LCA) methodology over the entire lifecycle of the power plants. The analysis distinguishes between ground-mounted and rooftop PV.

The analyzed ground-mounted PV installations are located in the Swiss Midlands. The assumed lifespan for both installation types is 30 years, and the full-load hours correspond to the assumptions in Chapter 5.

7.1
Environmental impacts compared to other technologies

A prospective life cycle assessment[89] is used to assess the environmental impact of power plants over their entire life cycle. All phases are considered, from the extraction of raw materials, construction and operation to dismantling and recycling. The analysis encompasses six environmental indicators: greenhouse gases, land requirements, damage to ecosystems, hazardous waste, radioactive waste and the need for critical metals.

The environmental impacts covered by this occur both at home and abroad. This geographical distribution differs from the cost allocation used in the value-added analysis. Environmental impacts throughout the supply chain are also taken into account, such as impacts from the mining of raw materials used in the power plant components. The prospective nature of the life cycle assessment also allows future developments up to the year 2050 to be taken into account. This approach also factors in the expected decarbonisation of the Swiss and global economy, for example by reflecting the future electricity mix, with an increasing share of renewable energy, in the calculations.

Figures 21 and 22 show the environmental impact of rooftop and ground-mounted PV in 2035. The maximum values for the other technologies considered (wind, nuclear power plants and gas-fired power plants) are also illustrated here for the sake of comparison. Rooftop PV plants have a comparably low environmental impact across all technologies. Ground-mounted PV plants have high land requirements and generate significant amounts of hazardous waste, with the highest levels in both categories compared to other technologies.

Key findings:

- The main source of greenhouse gas emissions for all power generation technologies is the combustion of fossil fuels. In the case of gas-fired power plants, direct CO_2 emissions from combustion during operation are the predominant factor. For all other technologies, emissions are mainly generated indirectly when fossil fuels are used in the different stages of the life cycle, such as for the manufacture of power plant components. Although it is assumed that the share of fossil fuels in the energy system as a whole will decline in the future and that such indirect emissions will also decline accordingly, it will not fall all the way to zero globally by 2050. Both rooftop and ground-mounted photovoltaics have low greenhouse gas emissions over the life cycle. Ground-mounted PV systems have slightly higher emissions, as more building materials, and particularly steel, are used for the substructure and installation.

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[89] A prospective life cycle assessment (LCA) is a life cycle analysis that assesses environmental impacts with a forward-looking approach under future conditions rather than retrospectively using current data. It combines traditional LCA methodology with scenarios or projections to assess how the environmental footprint of a product/process will develop in the future.

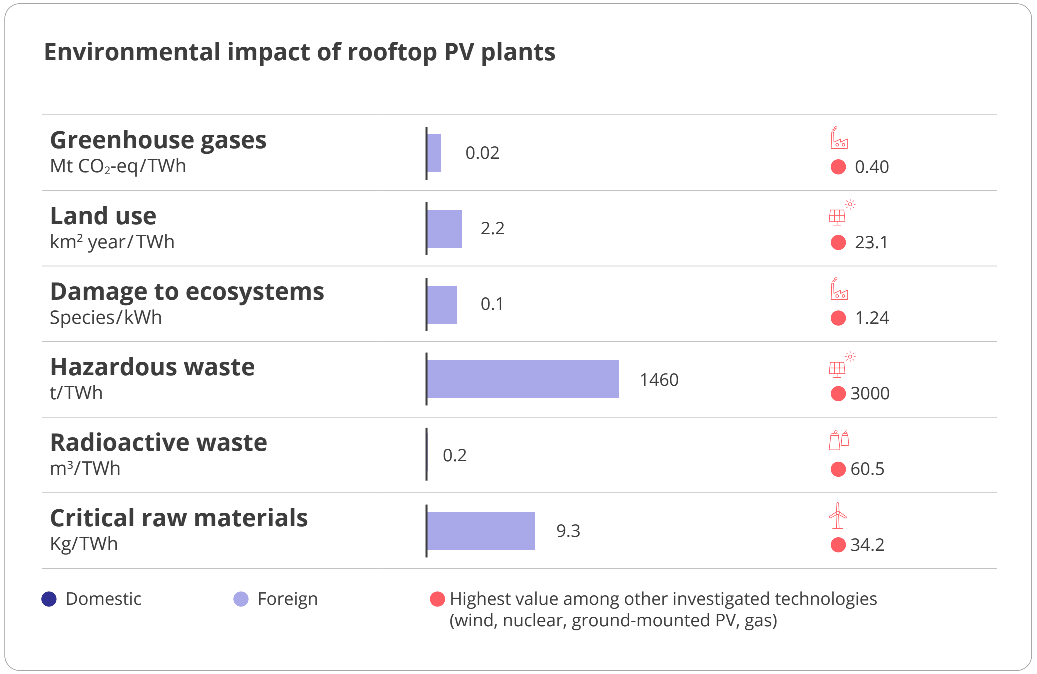

Figure 21: Environmental impact of a rooftop PV plant in 2035, broken down into domestic and foreign shares, compared to the highest values, or second-highest value, of other technologies. The values for gas are based on operation with natural gas; the values for nuclear power correspond to a new nuclear power plant in 2050.

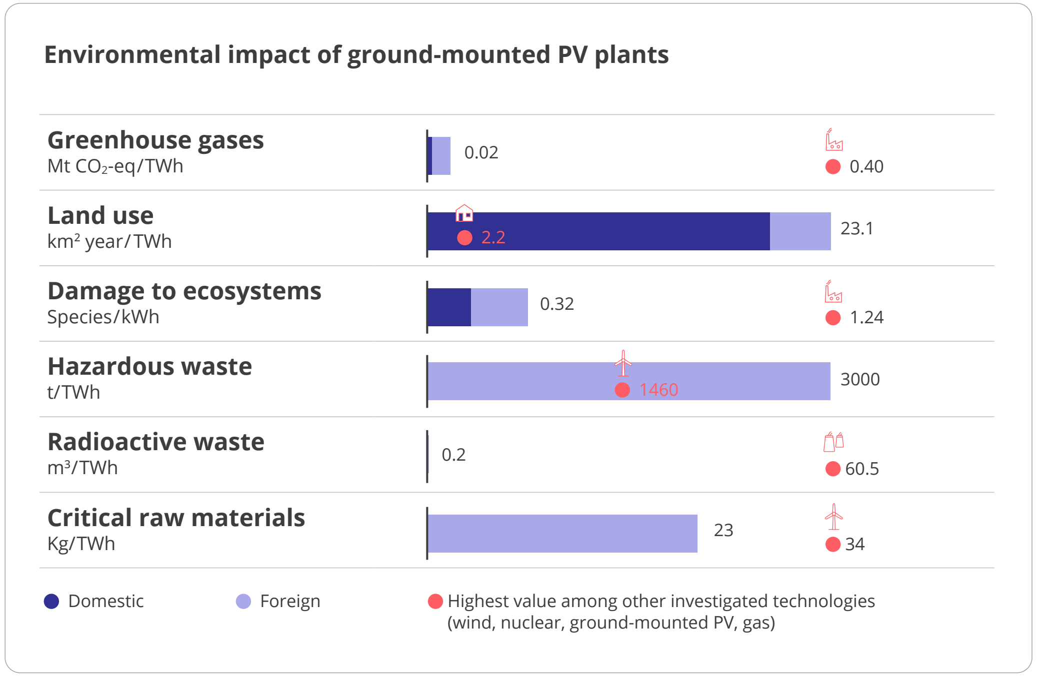

Figure 22: Environmental impact of a ground-mounted PV plant in 2035, broken down into domestic and foreign shares, compared to the highest values, or second-highest value, of other technologies. The values for gas are based on operation with natural gas; the values for nuclear power correspond to a new nuclear power plant in 2050.

- The land requirement is the total area that a technology occupies directly on site or in the upstream stages of its life cycle. Due to the installation of the system on land otherwise used for other purposes, ground-mounted PV has the highest domestic land requirement compared to other technologies. As module efficiency improves, this space requirement is likely to decrease slightly in the future. The domestic land requirement for rooftop PV is low, as the area used represents a dual use and is not reported as an additional land requirement. Foreign land requirements for ground-mounted PV and roof-mounted PV are comparable, as they mainly occur within the stages of the life cycle. However, due to the materials used, it is slightly higher than that of wind, nuclear or gas (powered with natural gas).

- Damage to ecosystems is caused by a variety of pressures and impacts, including, for example, pollutant emissions into air, soil and water, land and water use, and the effects of climate change. The sources of these impacts and damage are often spread over the entire life cycle of power generation technologies. Natural gas-fired power plants are at the upper end due to high emissions from operations. Ground-mounted PV plants have higher emissions than roof-mounted PV plants, as the domestic space requirement is higher.

- Hazardous waste includes non-radioactive waste that must be disposed of in underground landfills due to its hazardous properties and cannot be disposed of through waste incineration plants, for example. Here, ground-mounted PV ranks worst due to the high proportion of copper in the components. This is largely down to the copper requirement in the transformer for higher voltage levels, but also to cabling and the substructure. The hazardous waste from rooftop PV is considerably lower, as the grid connection is already available and a proportionally smaller transformer can be used (lower voltage level). In addition, the cabling and substructure are less complex. The copper requirements of grid expansion due to rooftop PV were not taken into account, but could increase the associated hazardous waste. In both cases, the hazardous waste does not arise in Switzerland, but in the upstream stages of the life cycle (dismantling and processing the copper).

- Radioactive waste comprises highly radioactive residues that have to be stored at deep geological repositories. Nuclear power generates the largest amount of such waste; for PV, on the other hand, the amount of radioactive waste is negligibly small and results only indirectly from the supply chain – e.g. from the share of nuclear energy in the electricity mix of the countries where components are manufactured.

- Overall, the demand for critical raw materials for power generation technologies is low. Cobalt and nickel are required in special steel alloys as well as in electrical installations; the greatest demand is for ground-mounted photovoltaic plants and wind power plants, as these technologies require a particularly large number of these special steels.

Recycling was not taken into account in the environmental analysis as the environmental impacts under consideration are deliberately based on the use of primary resources. By 2050, as a result of the extensive electrification of the economy, the demand for metals and minerals is expected to rise sharply, significantly exceeding the available supply from recycling. As long as the construction of new infrastructure remains the dominant factor, secondary raw materials can only cover the additional material requirements to a limited extent. It is only in the distant future, when large parts of this infrastructure reach the end of their service life, that recycling could make a significant contribution to reducing the environmental impact.

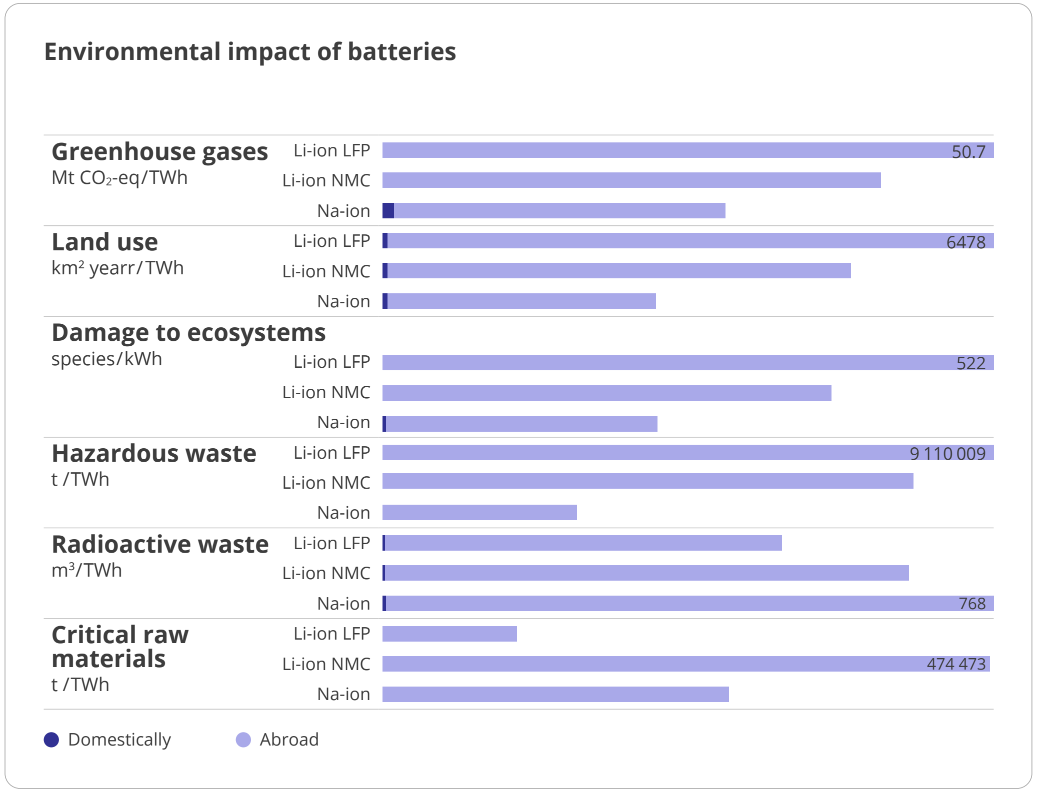

Figure 23: Environmental impact of lithium iron phosphate batteries (LFP), lithium ion batteries with nickel manganese cobalt cathodes (NMC) and sodium ion batteries (Na-ion). All values are per installed capacity in TWh for the year 2035.

7.2

Focus: Environmental impact of batteries

The environmental impact of stationary batteries mainly occurs during the manufacturing phase and is highly dependent on the battery technology used. Key pressures result from the extraction and processing of metals and minerals, and particularly critical raw materials such as lithium, nickel and cobalt, whose extraction is associated with comparatively high greenhouse gas emissions, land use, ecosystem damage and toxic waste. The analysis considers different types of stationary batteries, including lithium-ion batteries with nickel-manganese-cobalt (NMC) cathodes, lithium iron phosphate batteries (LFP) and sodium-ion (Na-ion) batteries.

Depending on the technology, greenhouse gas emissions from battery production are currently around 40–100 kg CO_2 equivalents per kWh of storage capacity, but are expected to fall significantly to 20–30 kg CO_2 equivalents per kWh of storage capacity by 2050. This development is largely driven by technological advances and the resulting higher energy densities, but also by the increasingly decarbonised electricity supply in global supply chains.

The requirement for critical raw materials differs significantly between the battery technologies considered and is largely determined by the respective chemical composition of the electrodes. The cobalt requirement is particularly pronounced for NMC batteries, while the lithium requirement is highest for both lithium-ion batteries examined. Nickel is mainly needed for NMC batteries, but also for the sodium-ion battery. By comparison, neodymium plays a minor role in terms of quantity. Demand is around three orders of magnitude lower overall and is at a similar level across all three battery technologies. The results for cobalt, lithium and nickel are largely determined by the direct metal requirement for the battery electrodes.

Among the battery storage systems evaluated here, sodium-ion batteries perform better than lithium-ion batteries across almost all environmental indicators under consideration. This is mainly due to the fact that sodium-ion batteries contain less critical raw materials. Their extraction and processing is often associated with significant environmental impacts as well as heightened supply risks. However, the expected technological efficiency gains, which are expected to be more pronounced for lithium-ion batteries than for sodium-ion batteries, as well as more environmentally friendly processes for raw material extraction and processing in the future, should reduce the environmental advantage of sodium-ion batteries in the future.

7.3

Focus: Recycling of PV modules and batteries

In Switzerland, the recycling of PV modules is organised through a system established by Swissolar and SENS eRecycling in 2013. Thanks to an upfront recycling fee charged at the time of purchase, disused PV modules can be handed in at collection points free of charge. The collected modules are transported to specialised, certified facilities in Germany and France for processing. There are no such facilities in Switzerland.[90] PV modules consist mainly of glass (90 percent); silicon wafers; composite films; metals such as copper, silver and aluminium; and a backing film, depending on the module type. The glass and silicon wafers can be reprocessed. Composite and backing films are incinerated, generating electricity and heat.[91] A similar system exists for batteries, operated by INOBAT, which can recycle up to 95 percent of the raw materials[92].

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[90] SENS eRecycling, 2026, Strong industry solution for the recycling of photovoltaic modules
[91] Swissolar, 2026, Disposal and recycling
[92] INOBAT, 2026, Battery recycling

08

Conclusion

Rooftop PV plants are currently being significantly expanded in Switzerland and are the fastest-growing power generation technology. To date, they have benefited from a high level of social acceptance, simplified approval (as a rule, only a reporting obligation instead of a building permit[93]) and solid profitability, also due to the direct subsidy and the reduced grid cost contribution for own use – an implicit subsidy. This combination makes rooftop PV currently the only technology with significant annual expansion in Switzerland. In addition to rooftop PV, there are other PV plants with great potential in Switzerland, such as ground-mounted PV, alpine PV and agri-PV, but their expansion to date has been minimal.

Rooftop PV generates little electricity in the winter half-year, which makes the technology very expensive for the expansion of domestic winter electricity generation.

In the case of rooftop PV plants, only around a quarter of the annual production is attributable to the winter half-year, and only 8 percent to the meteorological winter (December to February).[94] In addition, smaller rooftop PV plants in particular – which account for more than half of the available roof potential – have high electricity generation costs compared to other generation technologies. These plants have hardly any economies of scale and benefit little from falling module prices, as most of the costs are incurred through assembly.

Rooftop PV expansion can lead to additional distribution grid expansion; measures such as feed-in limits, controllable demand and battery storage should reduce this need for expansion.

A significant expansion of rooftop PV makes it probable that significant investments will be made in the distribution grid. In addition to the already increasing demand-driven grid expansion, high simultaneous PV feed-in on sunny days leads to additional strains. If local grid capacities are exceeded, the installation of additional PV plants at such feed-in points leads to "PV-driven" grid expansion, which can be very cost-intensive.

Decentralised integration measures can mitigate this need for expansion. They reduce both demand-driven and PV-driven peaks. These include targeted feed-in limits, controllable demand such as the charging of electric vehicles, and battery storage. If demand and battery storage are used in a ways that benefits the grid, electricity consumption, generation and storage can be postponed or controlled in a targeted manner to reduce load peaks in the distribution grid. However, these measures come at a cost. While feed-in limitation and load shifting typically address grid expansion in a cost-effective manner, home storage systems are not cost-effective for avoiding grid expansion from a system perspective.

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[93] Art. 18a (3) SPA, solar installations on cultural and natural monuments of cantonal or national importance always require a building permit. They must not significantly impair such monuments.

[94] Swiss Federal Office of Energy, 2025, Total electricity generation and charges in Switzerland

Today's tariff design increases the cost-effectiveness of PV plants with own use, but undermines the principle of allocating grid costs on a user-pays basis.

Under the current tariff structure, the economic appeal of PV plants with own use stems not only from the energy costs saved but also from the fact that no grid fees or national and municipal charges have to be paid for self-consumed electricity. These lower grid cost contributions play a major role in ensuring that plants with own use can be operated economically despite high electricity generation costs.

However, the problem is that end-users with PV plants do not contribute enough to cover the grid costs in relation to the costs they incur. The resulting shortfall must be borne by the other end customers via higher grid charges. This results in a redistribution of grid costs that is contrary the user-pays principle and that acts as an implicit subsidy for PV plants. Two aspects are key to understanding this problem. Firstly, 60 to 70 percent of the grid costs are structural in nature – they depend on the necessary cable lengths, which are determined by the number and location of the grid connection points. These costs are not influenced by own use. In contrast, only 30 to 40 percent of grid costs are attributable to the grid maximum load and the amount of energy transported. Secondly, scientific models show that PV expansion – even with own use – leads to rising grid expansion costs overall.

The implicit subsidy in the form of reduced grid cost contributions for own use therefore means that higher overall grid costs have to be allocated to fewer remaining end customers. The consumers wind up having to pay disproportionately for the grid. This implicit subsidy of PV plants is therefore borne by other end customers through higher grid charges.

Necessary adjustments to the tariff design would reduce the implicit subsidies for plants with own use; direct subsidies would have to be increased accordingly to ensure the viability of these plants.

The existing grid tariff design should be adapted to ensure that grid costs are distributed in line with the user-pays principle – and to promote behaviour that benefits the grid. Dynamic grid tariffs came into use for the first time in 2026, in some cases supplemented by performance-related components. As a result, the distribution of costs is shifting away from fixed labour prices (CHF/kWh) to actual grid usage, differentiated according to output and time. A higher proportion of fixed or performance-related components would be consistent with the cost structure of the grid. The optimal design of grid tariffs – which both allocates grid costs according to the user-pays principle and activates flexibility in a way that benefits the grid – remains to be conclusively determined. This will only become apparent in the practical implementation and through the accompanying learning processes.

Consistent implementation of such tariff adjustments would reduce the profitability of PV plants with own use, as the implicit subsidy would be eliminated, at least to some extent. The resulting direct subsidy requirements would have to compensate for this and would be correspondingly higher. It is essential to understand the following here: higher subsidy requirements would not lead to an additional burden on end customers. Instead of the current implicit redistribution via higher grid usage tariffs, the subsidy requirement would then be explicitly financed by the grid surcharge and thus rendered transparent. As a result, the subsidy requirement would be met by all end customers. This significantly increases transparency in assessing subsidy efficiency.

The SFOE plans to publish the subsidy efficiency based on the funds provided by the grid surcharge and the expansion achieved from 2027 onwards.[95] This is to be welcomed. However, it should be ensured that the current redistributive effects through savings with own use are taken into account accordingly.

[95] Federal Assembly, 2025, Creating transparency in the subsidy efficiency of all renewable technologies

Ground-mounted plants are the cheapest PV option and have the lowest subsidy requirements for electricity generation in the winter half year.

Compared to all other types of PV plants, ground-mounted PV has the lowest electricity generation costs and the lowest subsidy requirement for electricity generation in the winter half-year. These cost advantages are primarily due to simplified assembly processes and pronounced economies of scale. In addition, ground-mounted PV offers the advantage that the winter share of electricity can be increased without significantly increasing costs. As they are not tied to a roof pitch and orientation, ground-mounted plants can be optimally aligned and achieve a slightly higher share of winter electricity than rooftop PV plants. Installations in subalpine locations could further increase the share of winter electricity. They would take advantage of some of the benefits of alpine PV plants, such as significantly fewer foggy days than in the lowlands, while challenges such as snow loads and development would likely be less problematic than in high-alpine locations. This could lead to significantly lower construction costs.

In addition, ground-mounted PV is generally connected to the grid at a higher grid level than roof-mounted PV (GL5 or higher, instead of GL7), which means that the impact on the distribution grid is smaller and expansion costs can be reduced accordingly.

Ground-mounted PV has high potential; however, expansion is critically dependent on the cantonal implementation of suitable areas and approval procedures as well as the resolution of use conflicts.

The potential of ground-mounted PV throughout Switzerland is generally great, but it is difficult to quantify, as potential locations are subject to thorough assessment of competing interests. Use conflicts affect agriculture, the environment and landscape conservation in particular. Combined land uses, such as concurrent agricultural production in agri-PV scenarios, can partially alleviate these conflicts, but are often associated with higher costs and regulatory requirements.

Unlike in the field of wind energy, for example, there are no cantonal suitable areas for ground-mounted PV at the start of 2026. In the meantime, however, initial technical principles have been drawn up to assist the cantons in examining and defining suitable areas. In particular, areas with little or no conservation value – as identified in studies by the ARE, among others – can serve as an important starting point in this regard.

In order to enable the expansion of ground-mounted PV, it is now essential that the cantons comprehensively examine these spaces and identify suitable areas. The accelerated approval procedure in accordance with the legislation on accelerated procedures has improved the initial situation for ground-mounted PV in suitable areas. The cantons must now consistently implement both the provisions of the legislation on accelerated procedures and the requirements for defining suitable areas and weigh up use conflicts in a clear and transparent manner. In this way, they create the necessary prerequisites for the expansion of ground-mounted PV in terms of the duration and chances of success of the approval process.

In addition, communes can also go ahead in their use planning and provide special zones for smaller systems, e.g. on pre-contaminated areas. These are often easier to implement, economically attractive and well accepted.

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