Axpo Energy Reports Summary

24 March 2026

Foreword

Switzerland must ensure a reliable electricity supply during the winter. To achieve this, it is not only necessary to work closely with neighbouring countries and the EU, but also to establish a secure, affordable and low-emission domestic electricity supply. However, the expansion of winter electricity generation progresses slowly.

In 2025, Axpo launched a project to stimulate discussion on Switzerland's future electricity supply, with the aim of supporting the formation of opinion among politicians and the public in favour of a sustainable energy supply.

The focus of the work was on how electricity generation can be increased in winter and in particular on how four generation technologies – wind, nuclear, gas and solar – with the greatest expansion potential can contribute. Hydropower and other technologies are also considered, although their overall growth potential is limited.

The various technologies were assessed across several dimensions to provide a comprehensive overview of their advantages and disadvantages. Two realistic scenarios were developed to demonstrate how these technologies could be combined to shape Switzerland's future electricity supply. Recommendations on key measures that should be taken to ensure capacity expansion were also provided.

ACKNOWLEDGEMENTS & DISCLAIMER

This work is based on comprehensive analyses by experts from all Axpo business divisions, as well as on collaboration with external institutions (including ETH Zurich and the Paul Scherrer Institute). In addition, an Advisory Board, comprising members from across the political spectrum as well as experts from academia, consultancy firms, and environmental and industry associations, was consulted. This publication was produced on behalf of Axpo; contributions and feedback from the Advisory Board members were taken into account during the drafting process and incorporated into the discussion. The decision as to which aspects were included in the publication rested solely with Axpo, as did responsibility for the assessments and recommendations set out herein.

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Agenda

01 Problem statement
02 Technology comparison
03 Scenario analysis
04 Recommendations

01 Problem statement

Ensuring a reliable electricity supply in winter is one of the key challenges facing Switzerland

Switzerland currently enjoys a high level of security of supply, thanks to past investments; however, during the winter months, domestic electricity generation is already lower than demand.

- The supply is currently secure due to hydropower, nuclear power, new renewables and good integration into the European electricity system.
- In most years, winter electricity demand already exceeds winter production, as solar photovoltaics (PV) and hydropower are predominantly available in summer, while electricity demand is higher in winter than in summer.

Extensive electrification of the energy system is central to Switzerland's decarbonisation. To ensure the electricity supply, around 40 TWh of additional electricity generation must be added by 2050, 25 TWh of which is required during the winter months.

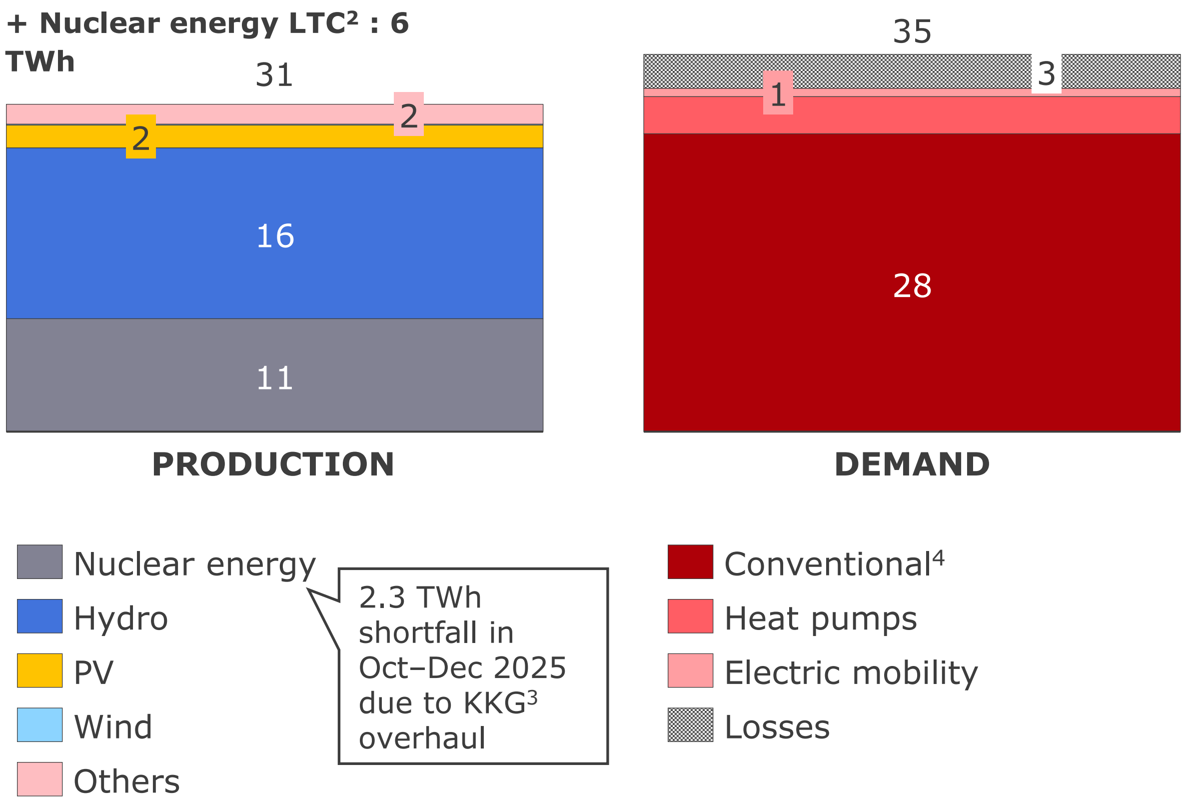
- Electrification is crucial for decarbonisation and reducing dependence on foreign energy.
- Electricity demand will rise – driven by the electrification of heating and transport, as well as by population growth – despite efficiency improvements. Additional factors such as the expansion of data centres may further increase demand.
- Parts of today's electricity generation fleet will be phased out, in particular due to the phase-out of nuclear energy.
- The current expansion focuses on photovoltaics, which leads to an even greater concentration of production in the summer.

Switzerland can solve the challenges of winter electricity supply, but the solution must ensure an efficient and affordable system.

- Expanding domestic winter electricity generation and integrating it into the European electricity system will ensure a secure and low-emission energy supply for Switzerland. At the same time, the future energy system – in line with the energy trilemma – must also be efficient and affordable for consumers.

Switzerland currently has a secure energy supply; however, during the winter months, domestic electricity generation is already lower than demand

Electricity mix for the winter half-year (Oct–Mar)[1] in TWh, 2025



Today, Switzerland has a secure supply, thanks to past investments and its integration into the European electricity market, which enables imports. However, electricity generation is already lower than demand during the winter months.

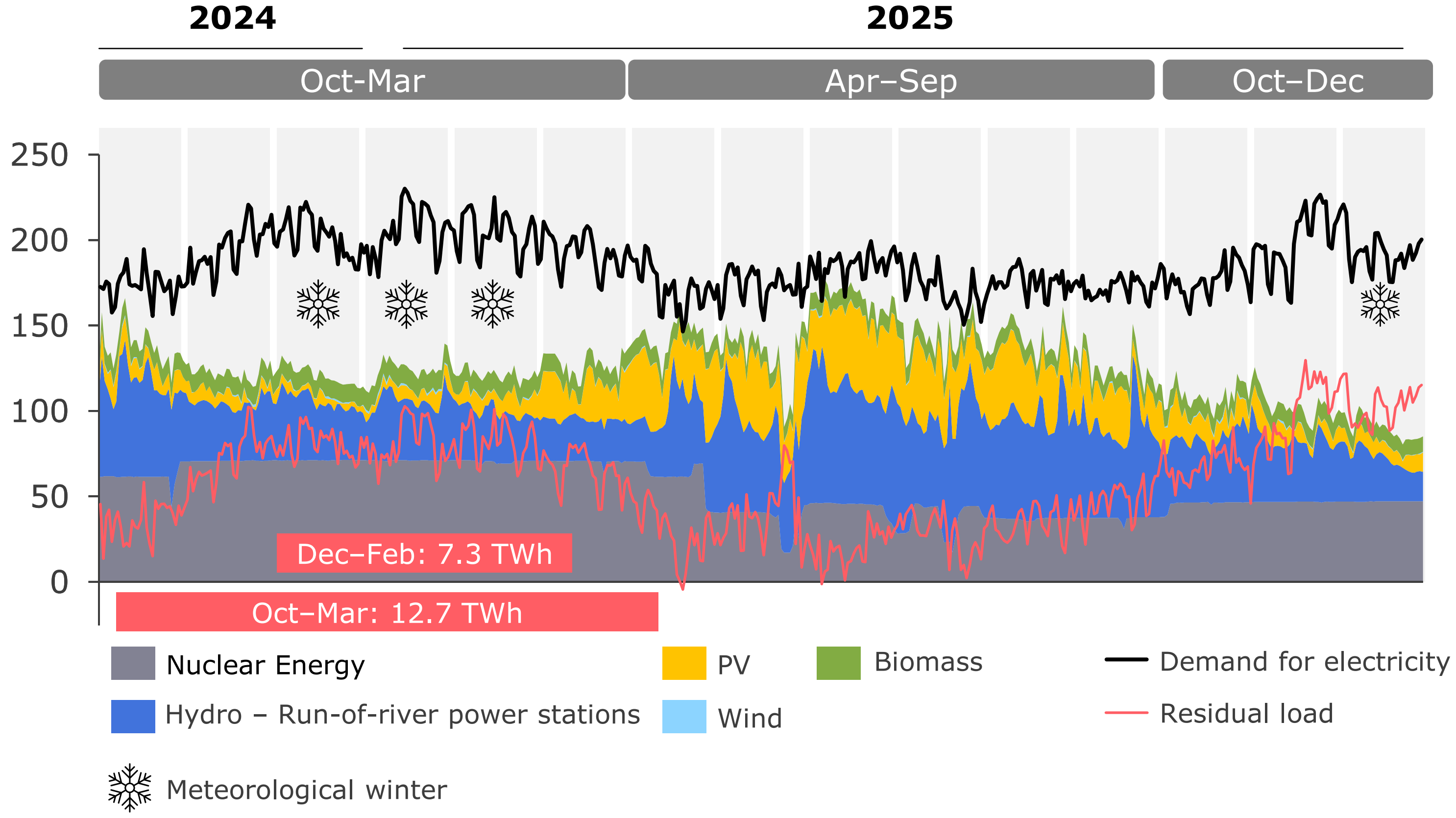
- The supply is currently secure due to hydropower, nuclear power, new renewables and good integration into the European electricity system.
- In most years, winter electricity demand is already higher than winter production, as solar energy and hydropower are mainly available in summer, while electricity demand is higher during the winter months than in the summer months.

1) Jan 2025 – Mar 2025 / Oct 2025 – Dec 2025; 2) Long-term contracts (LTCs) with French nuclear assets. These contracts secure the long-term electricity supply of approx. 12 TWh per year; 3) Kernkraftwerk Gösgen (KKG, Gösgen nuclear power plant); 4) Conventional demand comprises households, industry, commerce, services, transport, agriculture and the public sector. Source: SFOE (2025 electricity generation/demand)

Deep Dive: The focus is on the winter half-year, from October to March, as residual load is high and pumped-storage power stations can be deployed flexibly during this period

Residual load, GWh/day

Residual load is the difference between total electricity demand and electricity generation from variable renewable energy sources (solar and wind power) as well as nuclear energy and biomass (baseload production). The contribution of flexible storage power stations (11.9 TWh Oct 2024 – Mar 2025) and imports is not taken into account, as these must be used to cover the residual load.



Source: SFOE

<u>Why the winter half-year?</u>

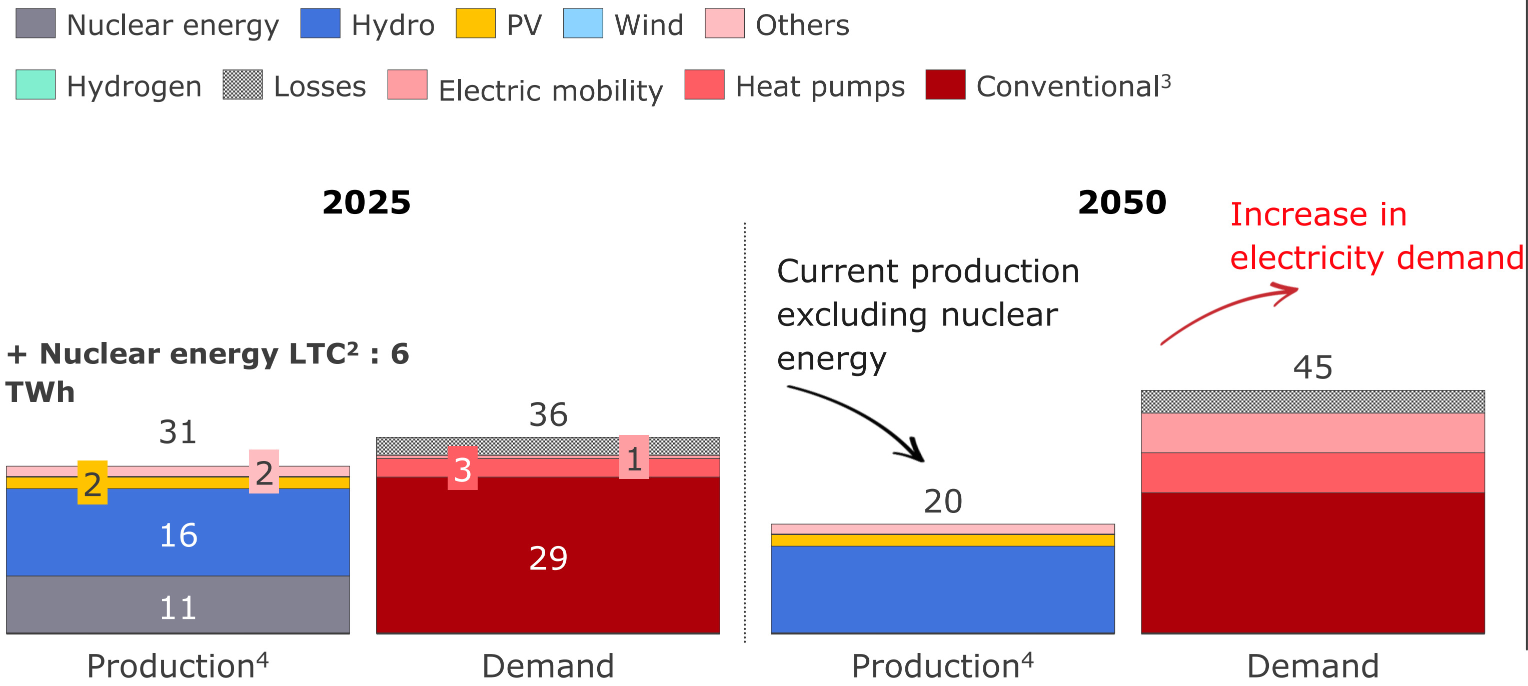
In this analysis, we always focus on the winter half-year, from October to March, as this is when domestic electricity generation from hydropower and PV falls, while demand rises. Under normal conditions, the residual load is highest during the meteorological winter (1 Dec – 28 Feb). This period accounts for 7.3 TWh of the 12.7 TWh residual load for the winter half-year. This is because the contribution from PV falls even further during this time.

Thanks to Switzerland's pumped-storage power stations and good import and export options, the country can shift energy quite effectively within the winter half-year as needed. In this way, renewable energy generation throughout the winter half-year can help slow the drawdown of reservoirs, leaving them available for critical weeks instead.

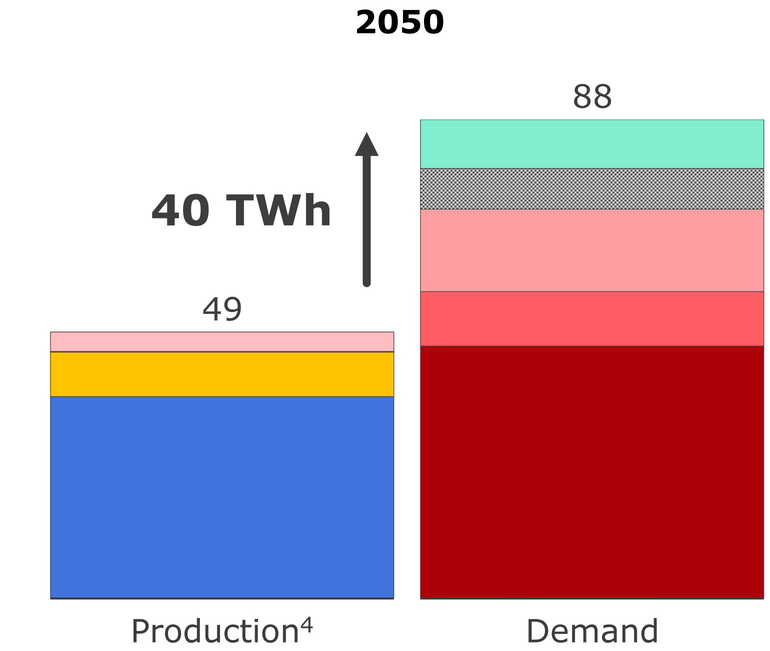
Electrification is key to decarbonisation. Increase in electricity generation required: 25 TWh in the winter half-year

The transition to a decarbonised economy is based on the increasing electrification of the energy system

Electricity generation and demand in the winter half-year (Oct–Mar[1]), TWh



Electricity generation and demand in the year, TWh

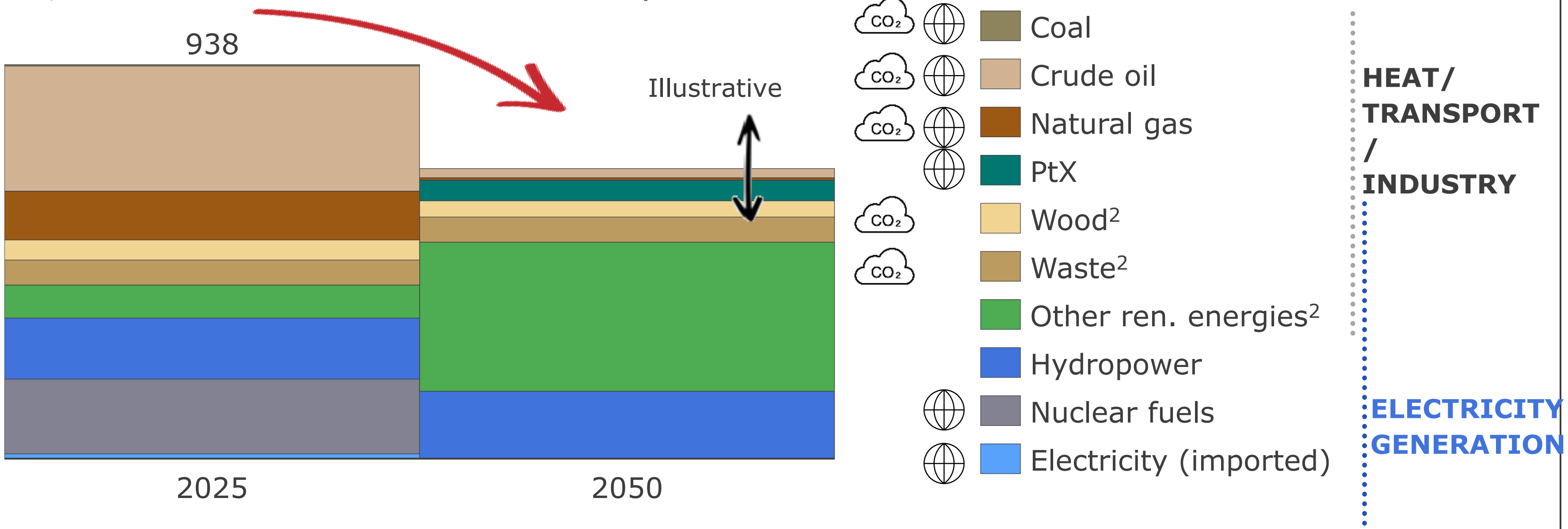


- Parts of the current electricity generation fleet will be phased out, in particular due to the planned phase-out of nuclear energy.
- The current expansion focuses almost exclusively on photovoltaics, leading to an even greater concentration of production in the summer.
- Electricity demand will rise – driven by electrification and population growth – despite efficiency gains. Other factors, such as the expansion of data centres, may further increase demand.
- By 2050, around 40 TWh of additional electricity generation capacity must be added, 25 TWh of which will be required during the winter half-year.

1) Jan 2025 – Mar 2025 / Oct 2025 – Dec 2025; 2) Long-term contracts (LTCs) with French nuclear assets. These contracts secure the long-term electricity supply of approx. 12 TWh per year; 3) Conventional demand comprises households, industry, commerce, services, transport, agriculture and the public sector. Source: SFOE (2025 electricity generation/demand); 4) 3 TWh shortfall in Oct–Dec 2025 due to KKG maintenance

Deep Dive: Electrification is key to decarbonisation and reducing dependence on foreign energy

Gross energy consumption, PJ
Trend in gross energy consumption by energy source
(Illustrative, based on the SFOE ZERO Basis scenario)



	2025	2050
Greenhouse gas emissions million tonnes of CO_2-equivalent[1]	~40	~12
Dependence on imports	~70%	~25%

Remaining emissions must be offset

CO_2 Major CO_2-emitters

Imported energy sources

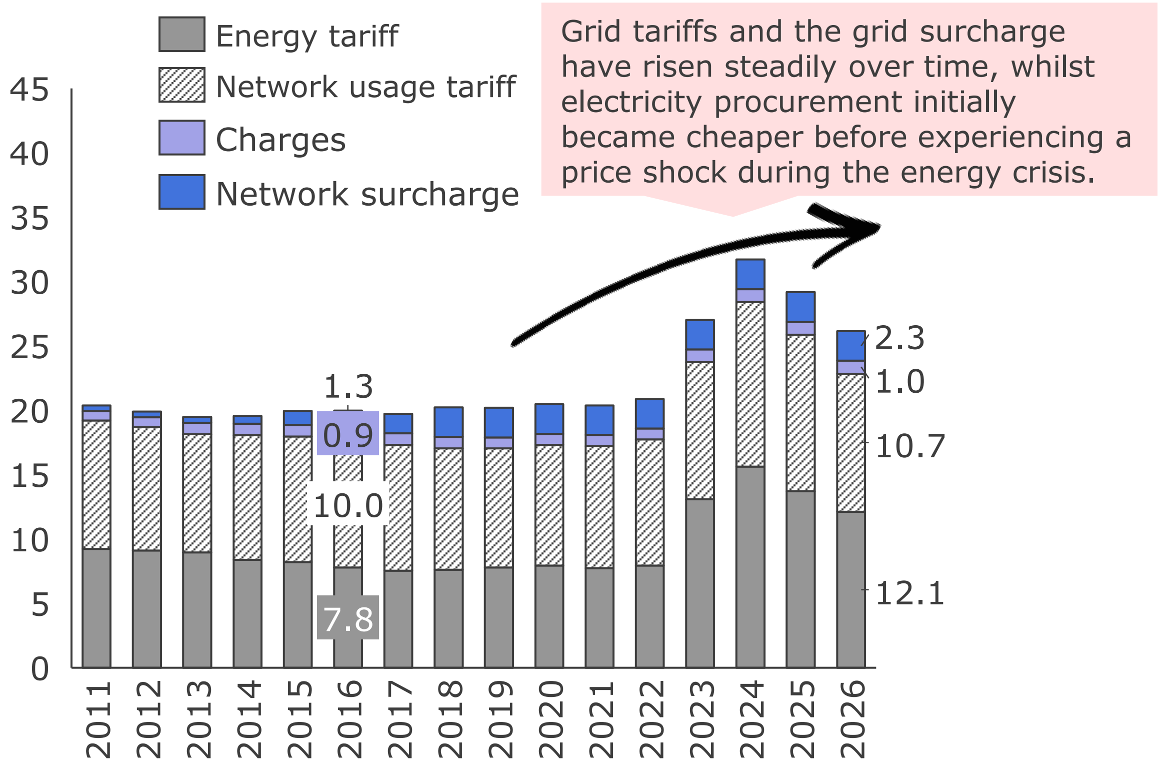
Increasing electrification is a key driver for reducing gross energy consumption, and thus, greenhouse gas emissions and dependence on imports, mainly through lower oil and natural gas consumption.

1) Total (domestic, excluding CCS, excluding NET); 2) Energy sources used for both electricity and heat generation; Source: SFOE

Switzerland can meet the challenges of winter electricity supply, but the approach must ensure an efficient and affordable system

Median electricity price for Switzerland (cents/kWh)

Median electricity price for Switzerland by consumption profile H4[1]



Expanding domestic winter electricity generation and integrating it into the European electricity system will strengthen Switzerland’s security of supply, while enabling a low-emission energy supply. At the same time, the future energy system must remain affordable for consumers.

When assessing affordability for customers, three factors must be considered:

Energy tariffs – energy supply:
Domestic electricity generation must be cost-effective and must be able to trade competitively on the European market.

Network usage tariff – grid expansion:
Grid expansion can be costly. Rising demand and decentralised generation, in particular photovoltaics, can lead to higher grid costs. However, measures such as demand flexibility or feed-in limits can be used to limit the costs of grid expansion.

Grid surcharge – subsidies:
In Switzerland, direct subsidies are financed by end customers through the grid surcharge. These subsidies should be used cost-effectively and targeted at the most pressing challenges – such as winter electricity supply – so as not to place an excessive burden on customers.

1) 4,500 kWh/year: 5-room flat with electric cooker and tumble dryer (without electric boiler), 25 A connection; Source: ELCOM

02 Technology comparison

To build a reliable energy system, Switzerland needs a balanced mix of electricity from different technologies, as each contributes in its own way (I/II)

Wind and nuclear power generate electricity predominantly during the winter months, while gas-fired power plants specifically can secure the winter supply. By contrast, photovoltaics produce mainly during the summer months.

- For wind power, around 66% of annual generation occurs during the winter months. For nuclear power, it is about 55%. Gas-fired power plants are operation-dependent and would likely be run almost entirely during the winter months.
- PV generates predominantly during the summer months. With around 27% of annual generation currently during winter, PV makes only a limited contribution to winter supply.

Acceptance varies greatly depending on the technology: rooftop PV enjoys high acceptance, wind energy faces well-organised local opposition with numerous objections, nuclear energy is highly polarising in society, and acceptance of gas-fired power plants depends largely on emissions and their operational profile.

- In general, acceptance at the national level differs significantly from acceptance at the local level.
- National surveys show public acceptance of 72% for wind, 56% for nuclear, 50–92% for solar and 39% for gas.
- Locally, rooftop PV enjoys very high acceptance. Wind is significantly more controversial at the local level; almost all projects face objections and delays. Nuclear power is very well accepted at existing sites. There is a lack of local experience with market-based gas-fired power plants; reserve power plants have been met with moderate resistance to date.

Current framework conditions are favourable for rooftop PV. For wind energy, the effects of the acceleration decree remain to be seen. Nuclear energy is ruled out by the ban on new construction, and market-based gas-fired power plants currently lack a suitable regulatory framework.

- Roof-mounted PV is comprehensively supported and subject only to notification requirements. For wind, estimated 7 TWh of suitable areas are available; the cantonal implementation of the acceleration decree is central to success, with formal municipal approval waived in this context.
- For nuclear energy, the lifting of the ban on new construction is required. In addition, accelerated approval procedures and suitable support instruments are needed. Gas-fired power plants are eligible for approval in principle but require adjustments to waste heat utilisation and the CO_2 levy scheme.

To build a reliable energy system, Switzerland needs a balanced mix of electricity from different technologies, as each contributes in its own way (II/II)

Roof-mounted PV can be rolled out quickly. The impact of the acceleration decree on wind power and ground-mounted PV remains to be seen. New nuclear power plants are only possible from 2045, while market-based gas-fired power plants are only possible from 2035.

- Current wind projects take an average of 13 years to be developed. The fast-track decree could reduce this to an average of 5 years, with a similar outcome for ground-mounted PV installations. Additionally, stronger nationwide planning is required.
- The approval process and construction of nuclear power plants could be possible in 14–16 years, if the ban on new construction is lifted and a suitable framework is established. This would earliest be possible from 2045. For new gas-fired power plants, the timeline is 2035.

Technologies have widely varying subsidy requirements for winter electricity: natural gas power plants have the lowest subsidy requirements, while rooftop PV has the highest.

- Wind and ground-mounted PV have similar subsidy requirements per MWh of winter electricity generated, while nuclear is slightly higher. Gas has the lowest subsidy requirement due to the high market value of the electricity generated. The subsidy requirement for small-scale rooftop PV is more than four times higher than that for nuclear.

Costs for grid expansion, which are already rising due to increasing demand, may rise further because of the expansion of electricity generation – especially in the event of significant growth in decentralised PV installations.

- Wind, nuclear, gas and ground-mounted PV have a moderate impact on distribution grid expansion, as grid connection takes place at higher grid levels. However, rooftop PV can trigger grid expansion and requires integration measures.

Roof-mounted PV has the highest domestic cost share. In the case of gas-fired power plants, a large proportion of expenditure flows abroad due to fuel imports.

Each technology has specific environmental impacts: CO_2-equivalent emissions from gas, radioactive waste from nuclear energy, hazardous waste and land requirements from solar PV, and demand for critical metals from wind.

Four generation technologies — wind, nuclear, gas and solar — can boost electricity generation in winter

- Wind
- Nuclear
- Solar
- Gas
- Hydro[3]
- Other[3]

Roof-mounted PV <30 kW
Other sizes covered in the technology report[1]

Infrastructure PV
On existing buildings, e.g. car parks

Facade PV
Vertically on building facades

Ground-mounted PV
On meadows, fallow land, etc.

Alpine PV
Alpine regions above 1500m

Agri-PV
Without restrictions on agriculture

Summary report

Technology reports

Today

Fossil natural gas is the current standard fuel and causes direct CO_2 emissions. Today, emission allowances are required for this under the European Emissions Trading Scheme.

Possible by 2050, but subject to high levels of uncertainty[2]

Carbon Capture and Storage (CCS)
Combustion of natural gas, paired with capture and permanent geological storage of the emitted CO_2.

Carbon Dioxide Removal (CDR)
Combustion of natural gas, with offsetting of the associated emissions using CDR credits from negative emissions technologies (NET).

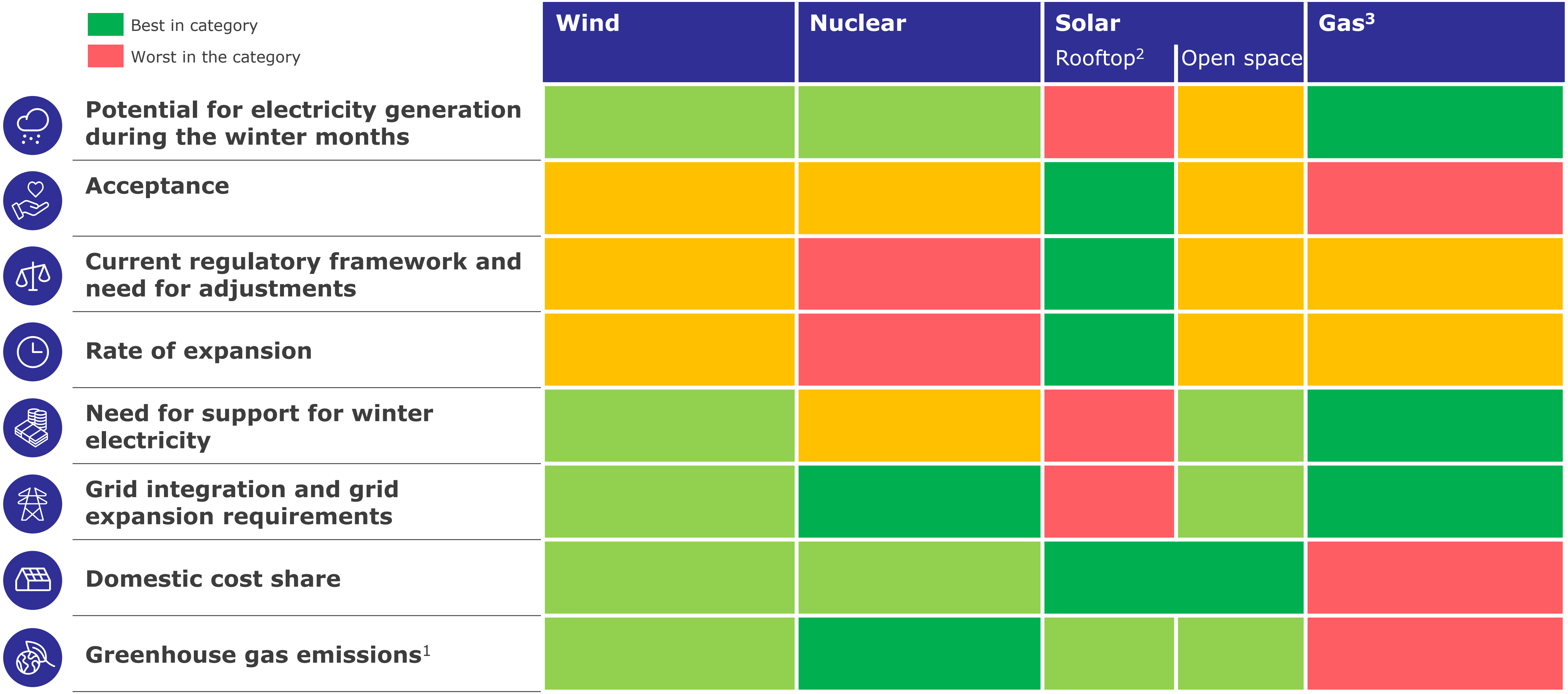
Green hydrogen (H_2)
Combustion of renewable hydrogen, that is either produced domestically or imported. Gas turbines can be built H_2-ready and, following retrofitting, operated on 100% H_2 .

Liquid renewable fuels
(bio/e-fuels) are used as alternative, storable fuels.

Renewable methane
Combustion of biogas (that has been partially processed or processed into biomethane) or synthetic renewable methane.

1) Decentralised batteries as an extension to rooftop PV are also analysed in the Solar Energy Technology Report; 2) Various challenges remain unresolved at present, such as the unknown availability and scalability of CDR, the lack of pipeline infrastructure for the transport and storage of CO_2 , the economic and technical challenges of hydrogen electrolysis, and the severely limited availability of biogas in Switzerland and neighbouring European countries; 3) Hydropower, biomass, geothermal energy and seasonal heat storage are also considered, but their overall growth potential is limited.

Four generation technologies – wind, nuclear, solar and gas – all have advantages and disadvantages



1) In addition to greenhouse gas emissions, the environmental indicators of land use, ecosystem damage, radioactive waste and hazardous waste, as well as the demand for critical metals (cobalt, lithium, neodymium, nickel) were examined. We cannot weigh these indicators against one another, so it is not possible to assess the overall environmental impact; 2) Rooftop PV <30 kW without a battery; 3) Natural gas participation in the Emissions Trading Scheme (ETS) for CO_2 emissions;

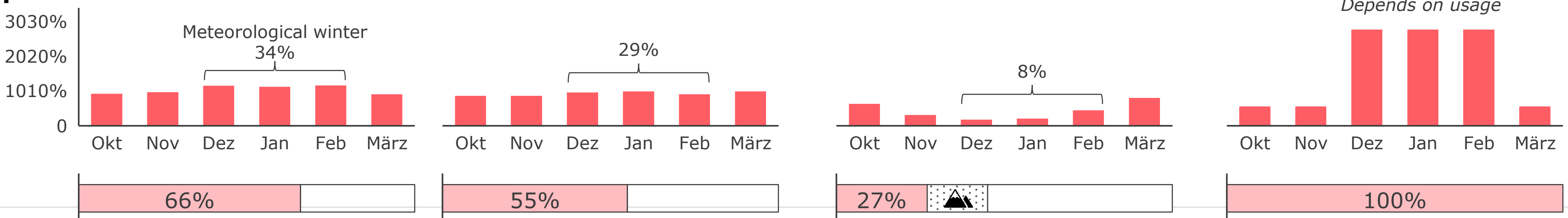
Wind and nuclear power generate electricity mainly during the winter months, gas-fired power plants provide targeted support for supply during winter, while solar power is generated mainly during the summer months

Electricity generation in the winter months

	Wind	Nuclear	Solar	Gas
Annual capacity and generation of a typical plant[1]	5 MW / 8.5 GWh FLH[2] : 1,500–2,000 hours	1,100 MW / 8.2 TWh FLH: approx. 7,000–8,000 h	30 kW / 0.03 GWh FLH: 850–1,200 h 10 MW / 10 GWh FLH: 800–1,200 h	500 MW / 1 TWh FLH: 2,000h (depending on market deployment)

Average generation in the winter half-year, monthly[9]

Total, as a % of annual generation



	Wind	Nuclear	Solar	Gas
Theoretical potential in the winter half-year[8]	~20 TWh	23 TWh[3]	~15 TWh[4] (rooftops) >3 TWh (solar plants)	6 TWh[5]
Winter production in 24/25	0.09 TWh[6]	12.6 TWh	1.8 TWh (almost exclusively on rooftops)	0.35 TWh in small combined heat and power (CHP) plants[7]

1) Reference assumption for calculating economic viability; 2) Full load hours, operating time of power plants at full load in hours; 3) Potential sites: Gösgen, Leibstadt, Beznau, Mühleberg. Two reference plants possible in Gösgen, one reference plant at other sites; 4) Of which around three-quarters on rooftops and the remainder on building facades; 5) Suitable sites appear to be available. Initial assessment indicates 12 potential sites, four of which with connection to planned hydrogen infrastructure, ten of which with connection to planned CO_2 infrastructure. Estimation with high uncertainty. It is expected that a reference plant would only be feasible at half of the sites; 6) 50 plants at 13 sites; 7) Due to a lack of data, it is assumed that 50% of production takes place during the winter half-year; 8) Sources for potential and share in the winter half-year: Wind: Wind Potential Switzerland 2022, SFOE; Solar: Concept for Utilisation Strategy for PV Potential, 2024, SFOE; 9) The meteorological winter is also shown, where the differences between the technologies are most pronounced.

Roof-mounted solar PV is widely accepted. In the case of wind power, objections at the local level cause resistance. Nuclear power is highly divisive. Acceptance of gas-fired power plants depends on plant's emissions.

Social and local acceptance

	Wind	Nuclear	Solar	Gas
Public acceptance (Based on national surveys)	Rather high 72%	Controversial 56% Population strongly polarised	Medium – Very high 92% 50%[1]	Low 39% Low-emission operation can increase acceptance
Local acceptance	Controversial All ongoing projects are facing objections and complaints, which are slowing down expansion. At existing sites, acceptance is high.	Very high New construction at existing sites, where there is local experience with power plants, tends to be well accepted.	Very high Good integration into existing infrastructure. Somewhat controversial Little experience in Switzerland, possibly higher for agri-PV[2].	Somewhat controversial Potentially feasible in industrial zones with sufficient visual and noise distance. First experience with reserve power plants shows moderate local resistance. However, it is unclear whether this is transferable to market-based gas-fired power plants.

Surveys on societal acceptance: *Our assessment is based on survey data from gfs.bern from 2025 (figures in % of eligible voters aged 18 and over who strongly/somewhat agree). 'Expansion of wind power' (72%), 'Wind turbines on the hill in front of one's own house, visible from the balcony' (59%); 'New nuclear power plants are being considered in Switzerland' (56%). 'Expansion of solar panels on buildings' (92%); 'Large solar power plants in the mountains on open meadows' (50%); 'Gas-fired power plants 10 kilometres from one's own home' (39%).*

1) Based on survey data on Alpine PV from gfs.bern and Fesenfeld et al., 2026; 2) Agri-PV comprises installations that lead to an improvement in agricultural productivity. These installations can enjoy a high level of acceptance.

Current framework conditions for rooftop PV are good. For wind power, the impact of the acceleration decree remains unclear. New nuclear energy is banned, and market-based gas-fired power plants lack a suitable framework

Current regulatory framework and necessary adjustments

	Wind	Nuclear	Solar	Gas
Approval process *Deep dive on the next slide*	Suitable areas are partially available but need further designation. The acceleration decree (new PGV[1]) must be consistently implemented. No municipal consent is required.	The ban on new construction must first be lifted. To ensure commissioning by 2050, the approval process must be accelerated. Assessment is based on 'state of the art retrofitting technology' from the construction phase onwards.	Roof-mounted PV: In most cases, only subject to notification (no permit required). Ground-mounted PV: No suitable areas have been identified yet. Acceleration decree improves the situation, as is the case with wind power.	Eligible for approval in principle, but cantonal requirements regarding waste heat utilisation will likely need to be adapted.
Support and further details	Supported by investment grants, a sliding-scale market premium and project planning grants.	No support available. State funding for project development and support (e.g., market premium or investment grant) and guarantees (e.g., for tail risks) are necessary	Roof-mounted PV: Comprehensive support in place. Self-consumption is key. Ground-mounted PV: Supported by investment grants or a sliding-scale market premium.	No support available. Government support is required, e.g., through the capacity market. The double burden through the Emissions Trading Scheme (ETS) and the CO_2 levy must be removed[2]. Otherwise, power plants are not competitive in the EU electricity market and only suitable for reserve operation, which requires higher subsidies.

1) Planning approval procedure; 2) A refund of the CO_2 levy is effectively ruled out following the partial revision of the CO_2 Ordinance (effective 1 January 2026), as external costs are now set at CHF 430/t CO_2; ETS and CO_2 levy currently at approximately CHF 120/t CO_2

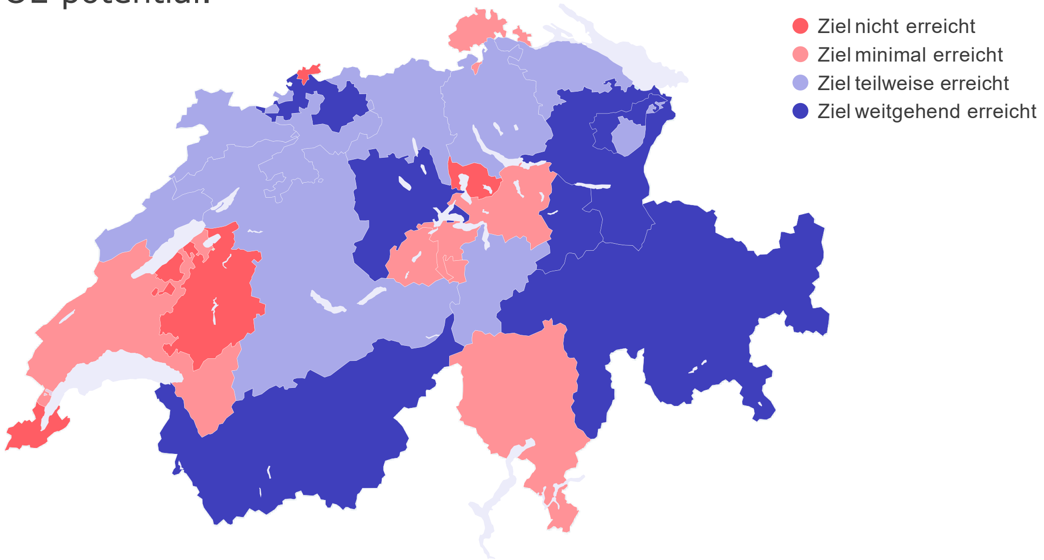
Deep Dive: Some cantonal "suitable area" zones for wind power are available, but there are considerable differences between cantons. There are no "suitable area" zones for ground-mounted PV yet

Based on analyses using Basler&Hofmann

Adjustments to the cantonal structure plan for suitable areas

Cantonal target achievement[1]

This is measured by the adjustments made to the structure plans, to designate suitable areas for wind turbines in accordance with the SFOE potential.

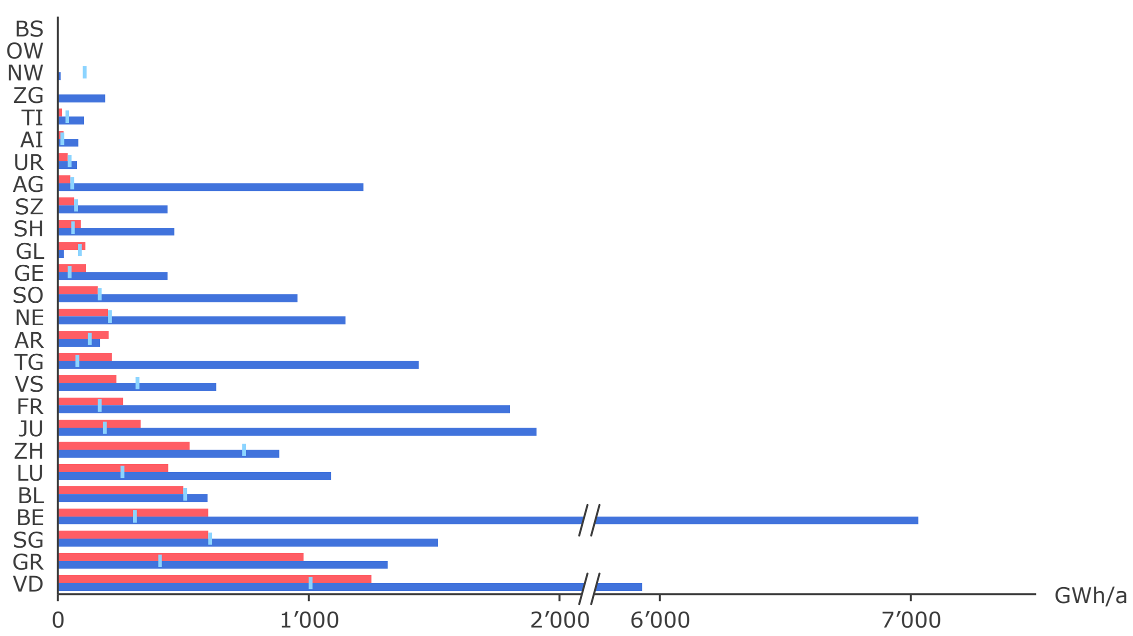


To date, **not all cantons** have **revised** their **structure plans**, or are at different stages of doing so.

No suitable areas for large-scale **photovoltaic plants** have been designated yet.

Wind potential of the designated suitable areas

Comparison of the current regional plans with the SFOE 2050 potential and the cantonal targets for wind energy.



A potential of 6.9 TWh for wind power is identified in the cantonal structure plans, although not all cantonal targets have been met.

1) Achievement of targets as a qualitative assessment: has the respective canton made any adjustments to the structure plan since the publication of the new potential, and if so, to what extent?

The acceleration decree's impact on wind power remains to be seen. New nuclear power plants will not be possible before 2045, and not before 2035 for market-based gas-fired power plants. Rooftop PV is progressing rapidly.

Expansion rate

	Wind	Nuclear	Solar	Gas
Timeline for adapting the regulatory framework	Additional suitable areas identified and acceleration decree implemented in cantons → *by ~2027–30*	Ban on new construction lifted and suitable framework established → *possible by ~2031*	Roof-mounted PV as is. For ground-mounted PV, suitable areas designated and acceleration decree implemented in cantons → *by ~2027–30*	Provision of state funding in place and cantonal energy laws amended → *possible by ~2030*
Approval process and construction — **Designation in cantonal structure plan**	If in a suitable area, already in place	Not required for nuclear energy[1]	If in a designated area, already in place	Pending
	Municipal approval Objections Start of construction Commissioning **~6 years**	Framework authorisation Referendum Planning permission Objections Start of construction Commissioning **~14–16 years**	Municipal approval Objections Start of construction Commissioning **~6 years**	Tender Building permit Objections Start of construction Commissioning **~10–13 years**

Current projects take ~13 years. The impact of the acceleration decree is still unclear and **strengthening nationwide planning** could help

Roof-mounted PV systems with an installation period of **less than one year**. In most cases, no planning permission is required. Installations are subject to notification only

Deep dive on the next slide

1) No cantonal permits are required for nuclear power plants

Deep Dive: The expansion of wind power could be further accelerated by strengthening nationwide planning, with the same applying to ground-mounted solar PV

Challenges in the current system, including the acceleration decree: limited coordination and federal government control powers
Spatial planning is fundamentally a matter for the cantons and municipalities. The federal government supports the cantons from a higher-level perspective by providing conceptual frameworks, such as the Wind Concept or the SFOE’s potential study. However, these frameworks are generally not very binding and therefore have, at best, a limited coordinating effect. The federal government largely lacks the resources and powers to maintain and exercise a nationwide overview and control of potential sites and wind projects, towards security of supply (particularly during the winter months).

Strengthening nationwide planning

These challenges could be addressed, for example, by making the federal government’s conceptual guidelines more binding for the cantons, strengthening coordination between the federal government and the cantons, and supporting cantonal implementation through the establishment of a federal monitoring system. This could motivate the cantons to designate additional suitable areas, contribute to enhanced coordination between the federal government and the cantons as well as between the cantons, with a view to the national perspective, and strengthen the implementation and comparability of cantonal planning. The inclusion of strategically significant wind energy projects in the federal concept could enable explicit national prioritisation. This would send a clear national signal in favour of these projects and provide them with stronger political and planning support.

Wind round table[1]

A supporting or further measure could be the establishment of a ‘Wind Round Table’. Through this forum, the federal government, cantons, project developers and other stakeholders could exchange views and, where possible, coordinate their positions at a higher level. This could cover matters such as the status of planning (nationwide and in individual cantons) and specific projects. This direct exchange could strengthen acceptance among the cantons and federal stakeholders, both in relation to suitable areas and to specific projects.

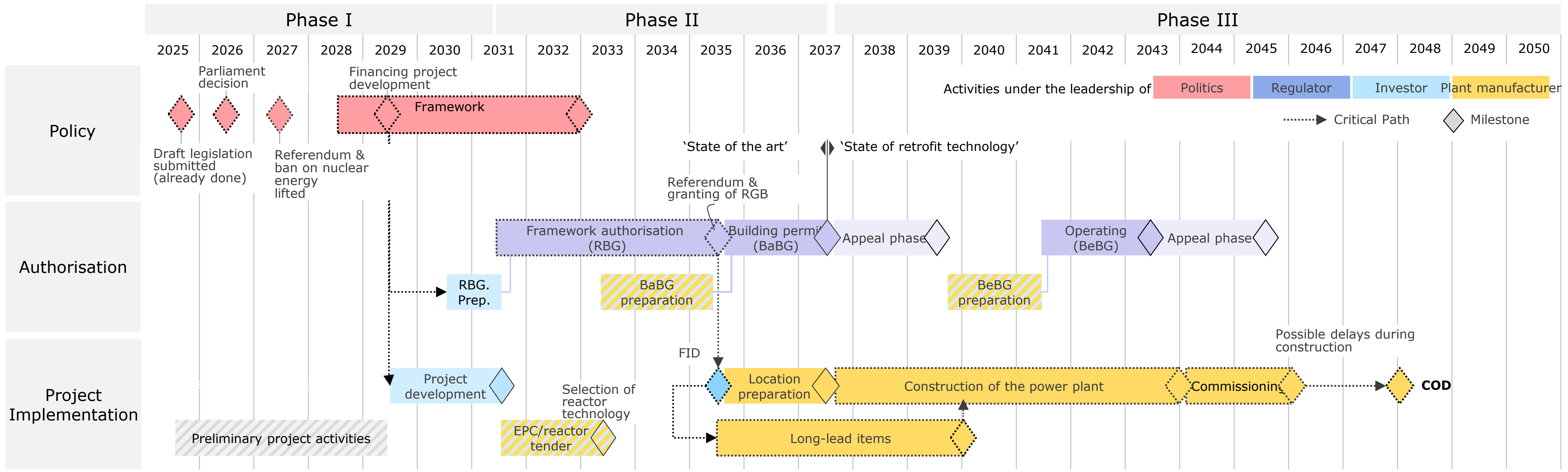
Further measures

Should the expansion targets set by the federal government still not be achieved, even with strengthened nationwide planning, further measures would need to be considered, such as the creation of a national sectoral plan for wind energy.

1) Similar to the already implemented Hydropower Round Table, where the approval process for selected hydropower projects was simplified.

Deep Dive: New nuclear power plants are possible from 2045 at the earliest, but this requires a clear national strategy, broad political support and high levels of public acceptance

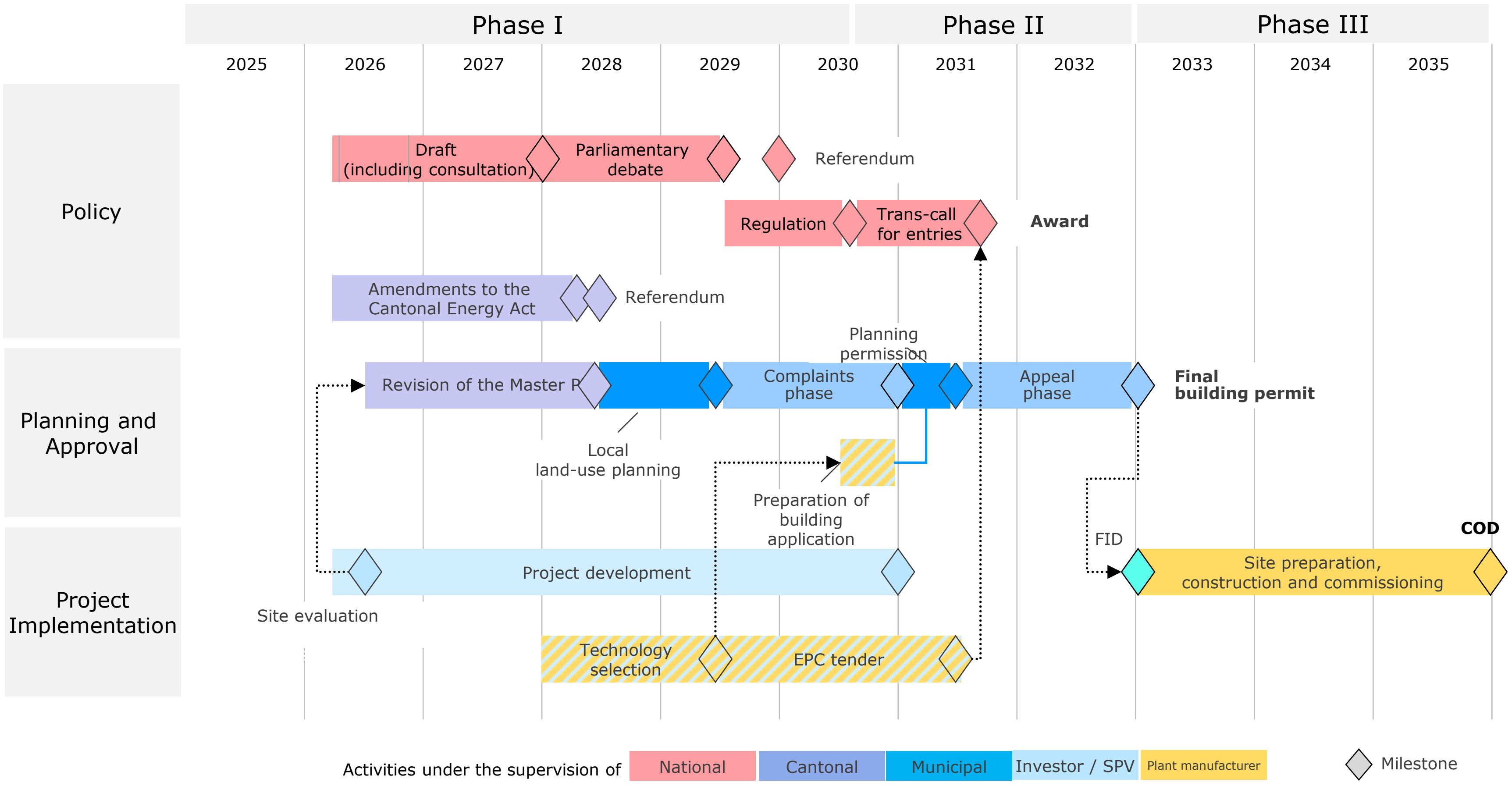
Timeline for the construction of new nuclear power plants in Switzerland, including adjustments to the licensing procedure



Is this timeline realistic? *The construction of a new nuclear power plant requires the lifting of the statutory ban on new builds. The counter-proposal to the 'Blackout Initiative' is expected to be finalised in parliament by the end of 2026 at the latest. If adopted, a referendum is expected in mid-2027. Beyond this, a suitable regulatory and economic framework is needed to enable actual investment in new nuclear power plants. This framework includes adjustments to the licensing procedures, risk-sharing instruments and support across all project phases, as well as guarantees for further risks such as adjustments during the construction phase. The following measures are incorporated into the timeline shown in this figure: 1. Framework licence as a site preparation licence; 2. Removal of the suspension that appeals trigger on building permits and operating licences; 3. Plants under construction will be assessed in the same way as existing plants, based on 'state of the art retrofitting technology'.*

Deep Dive: New gas-fired power plants could be possible by 2035, but this requires adjustments to legal and planning frameworks at the national and cantonal levels

Timeline for the construction of new gas-fired power plants in Switzerland

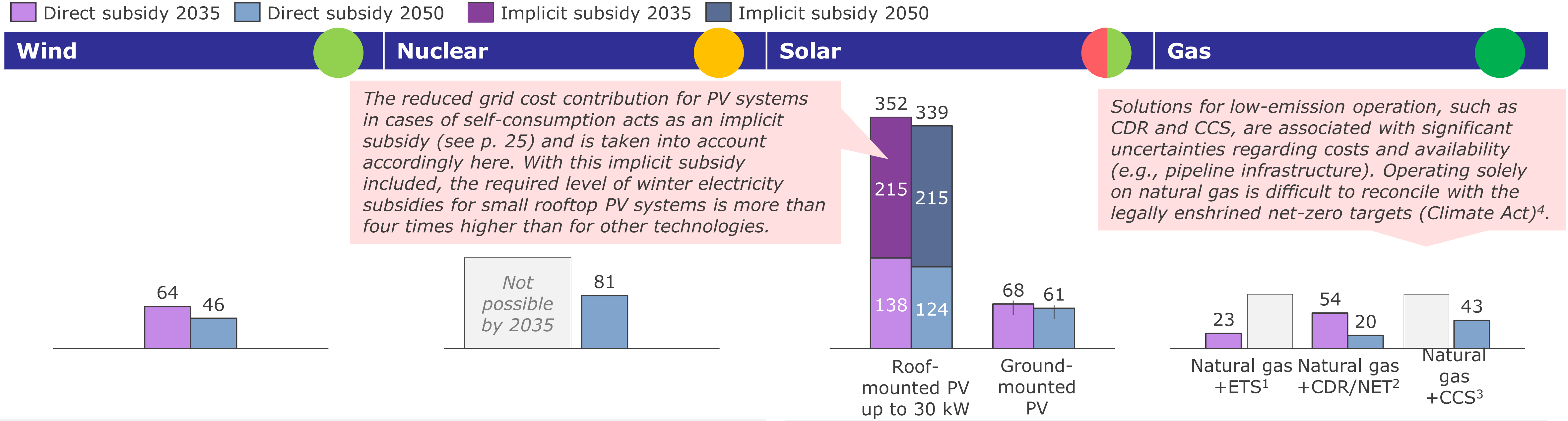


Why does the timeline for market-based gas-fired power plants run over at least 10 years?

The existing regulatory framework is not geared towards market-based gas-fired power stations. First, the legal and planning foundations must be established (Phase I). At national level, this involves tenders for generation capacity and the removal of the double burden imposed by the Emissions Trading Scheme (ETS) and the CO2 levy. At cantonal level, the requirements for waste heat utilisation in the relevant energy law (and associated energy ordinances) must be amended. An early site selection is important so that work on adapting the structure plan can begin immediately. Subsequently (Phase II), the federal government will issue the tender. In parallel, the documents required for the building permit, starting with the technology selection, can be prepared. Once the legally binding building permit has been obtained and the auction award has been secured, the final investment decision can be made (Phase III).

Technologies' subsidy requirements for winter electricity differ vastly, with this being lowest for natural gas power plants and highest for rooftop PV

Subsidy requirement per MWh of winter electricity, in CHF_{2024} /MWh real



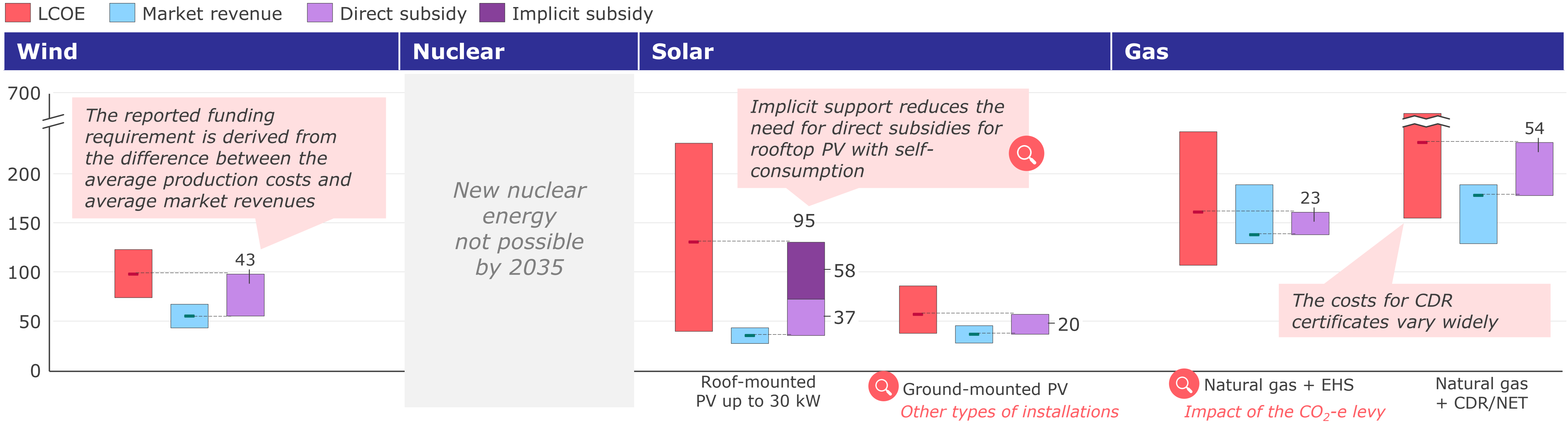
Why is the funding requirement for winter electricity important?
Expanding the domestic winter electricity supply is a key prerequisite for security of electricity supply. The funding budget should be used efficiently. It is therefore important to understand the funding requirements of the individual technologies for winter electricity generation. This so-called funding efficiency helps to ensure that the available funds are used in a targeted and effective manner.

How do we determine the funding requirement for winter electricity?
The funding requirement is derived from the difference between the levelised cost of electricity and the full-year market revenues, as well as additional effects (e.g., implicit support for rooftop PV with self-consumption). This difference is then allocated to the amount of electricity generated during the winter half-year. To do this, the funding requirement is divided by the winter electricity share (wind: 66%, nuclear energy: 55%, solar: rooftop PV 27%, ground-mounted PV 30%, gas: 100%).

1) Participation in the emissions trading scheme for CO_2 emissions; 2) Combustion of imported fossil methane and offsetting the associated emissions with carbon dioxide removal (CDR) certificates from negative emissions technologies (NET). Elimination of double taxation through the CO_2 levy on gas-fired power plants is assumed; 3) Carbon Capture and Storage: capture and storage of CO_2 emissions. Reduces emissions by 90%. It is assumed that the remaining emissions will be offset via CDR/NET; 4) Federal Act on Climate Protection Targets, Innovation and Strengthening Energy Security (KlG). This stipulates that emissions must be reduced as far as technically and economically feasible. Negative emissions (e.g., CO_2 removal) may only be used for remaining residual emissions

In 2035, electricity generation will still rely on government subsidies, but production costs and market revenues will vary widely

Electricity generation costs and revenues, in CHF_{2024} /MWh real[1]



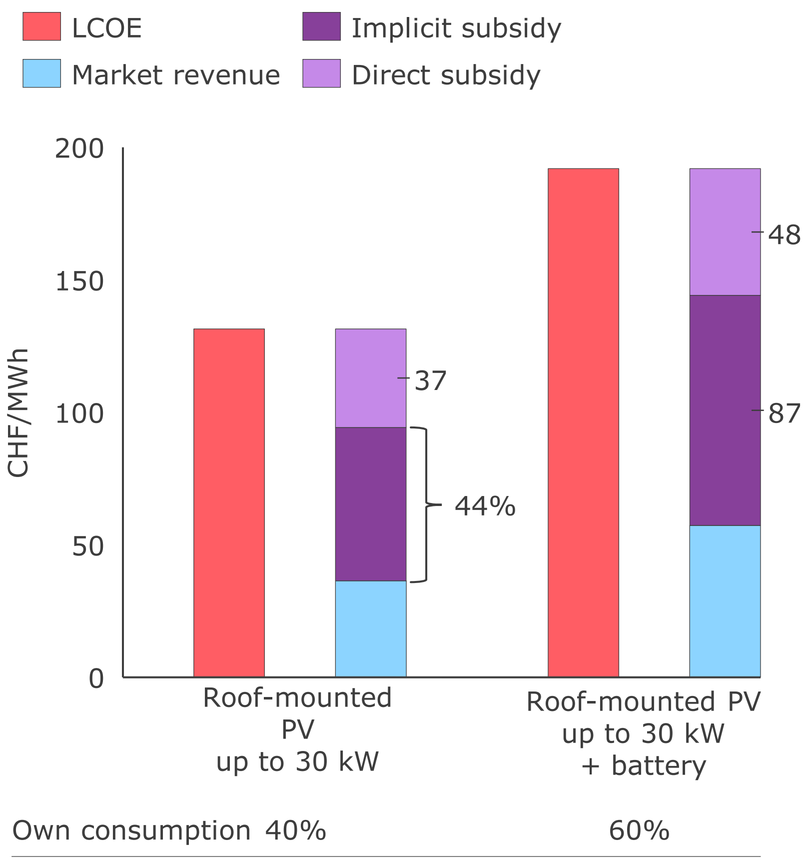
What are levelised costs?
Levelised costs are the average cost per unit of electricity generated (CHF/MWh). They encompass all expenditure incurred by a plant over its lifetime: construction, operation, fuel, CO_2 costs, financing, disposal and decommissioning. These costs are then allocated to electricity generation. Caution: whilst levelised costs help when comparing technologies, they neglect the revenue side and other systemic advantages and disadvantages, such as the need for grid expansion or storage requirements. For a comprehensive assessment, we therefore analyse two synthesis scenarios.

How do we model market revenues?
No one knows what electricity prices will be by 2050 or beyond. This is why we use fundamental models[2] to derive various scenarios for the future development of electricity market prices. The achievable market revenues vary depending on the technology and the time at which electricity is generated. For example, market prices tend to be low during very sunny hours – this effect is known as 'cannibalisation'. In Switzerland, electricity prices are also heavily influenced by developments abroad. In the case of rooftop PV, battery storage can help increase the revenues.

1) Assumed weighted average cost of capital (WACC) for mean values: wind 4%, nuclear 5%, rooftop PV <100kW 3.5%, other PV 4%, gas 4%; 2) For the long-term outlook, fundamental models are generally used. These are not based on historical data, but explicitly model future power plants and load development, and replicate current market mechanisms and price formation.

Deep Dive: The cost-effectiveness of rooftop PV depends heavily on reduced contributions to grid costs and surcharges due to self-consumption, which acts as an implicit subsidy

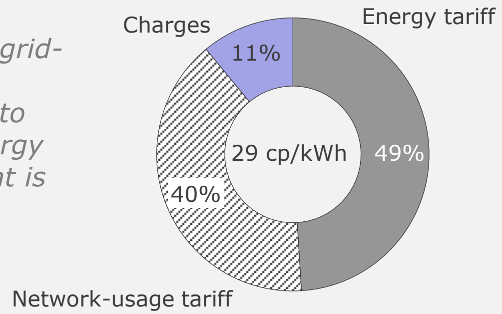
Cost-effectiveness of rooftop PV in 2035, in CHF_{2024} /MWh (real terms)



1) ElCom, Electricity prices in Switzerland, consumption profile H4

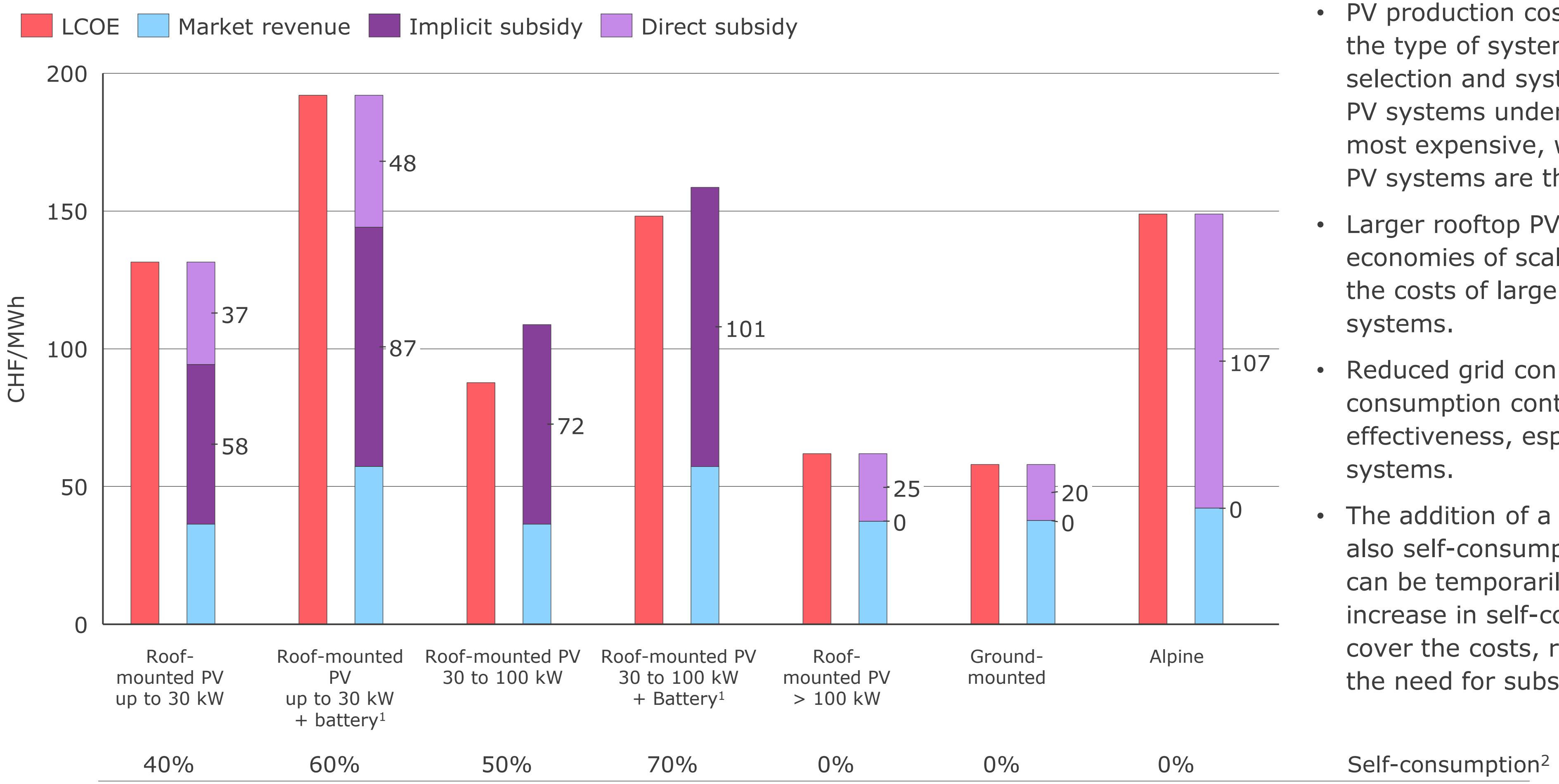
- End consumers with PV systems can reduce their share of grid costs and the grid surcharge through self-consumption (see box below). While this improves the economic viability of the individual PV system, the resulting shortfall in grid cost coverage must be borne by other end consumers through higher grid charges. The reduced contribution constitutes an implicit subsidy for PV systems.
- The costs of expanding and maintaining grids are largely fixed costs. The electricity grid thus acts as a kind of insurance, ensuring that the desired amount of electricity can be obtained at any time – even for consumers with a very high proportion of self-consumption. The ‘polluter pays’ principle therefore requires that all end customers continue to contribute appropriately to grid costs.
- Consequently, this leads to a redistribution under the current grid tariff structure: households with PV systems and self-consumption pay an ever-decreasing share of the total grid costs, while households without PV systems pay more.
- A distribution of grid costs based on the ‘user pays’ principle would require adjustments to the existing grid tariff design. For example, so-called power tariffs could be applied more widely, which thereby also providing incentives to reduce consumption peaks.

Why is there a reduced grid cost contribution?
Grid costs are currently financed largely through consumption-based grid-usage tariffs. Of the average household electricity tariff in the basic supply of approx. 29 Rp./kWh in 2025[1], 12.2 Rp./kWh is attributable to the grid usage tariff and 2.3 Rp./kWh to levies. In addition to the energy tariff, grid-usage tariffs and levies can also be saved on electricity that is self-consumed from rooftop PV[2]. By saving on grid-usage tariffs, the contribution to grid costs is reduced accordingly.



Deep Dive: PV costs and revenues vary significantly, depending on the type of system and the potential for self-consumption

Economic viability of PV systems in 2035, in CHF_{2024} /MWh (real terms)



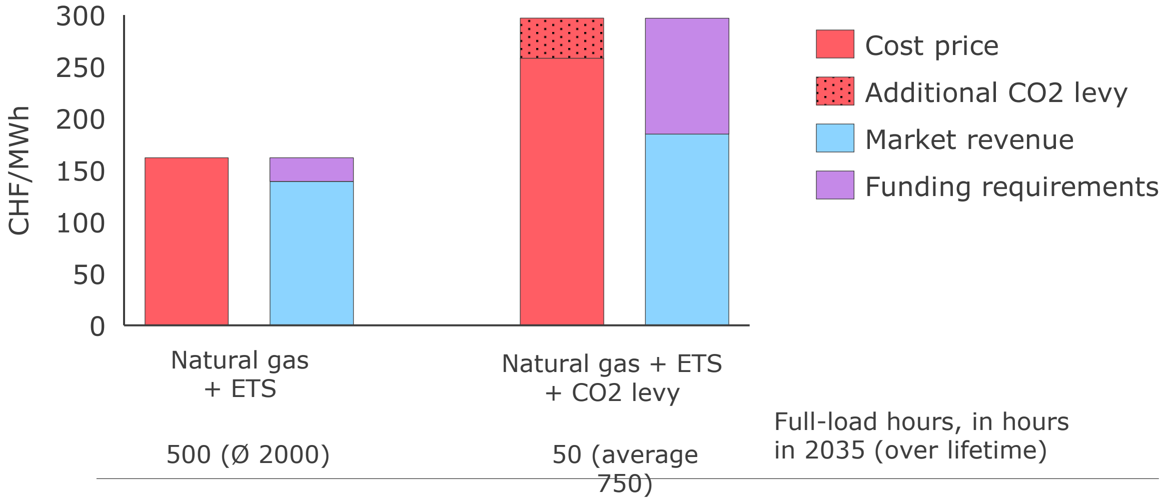
- PV production costs are heavily influenced by the type of system, installation costs, site selection and system size. Small-scale rooftop PV systems under 30 kW and alpine PV are the most expensive, while large ground-mounted PV systems are the cheapest.
- Larger rooftop PV systems benefit from economies of scale and therefore come close to the costs of larger ground-mounted PV systems.
- Reduced grid connection charges for self-consumption contribute significantly to cost-effectiveness, especially for smaller rooftop PV systems.
- The addition of a battery increases costs but also self-consumption, as surplus PV production can be temporarily stored. However, the increase in self-consumption does not fully cover the costs, resulting in a slight increase in the need for subsidies.

1) Assumed battery capacity: 1.5 kWh per kWp of PV output, source: Swissolar; 2) The proportion of self-consumption depends on various factors, including individual consumption patterns. Average values are assumed here in accordance with *the Federal Act on a Secure Electricity Supply from Renewable Energies: Amendment to the Energy Ordinance upon entry into force – Explanatory Report*

Deep Dive: The generation costs and subsidy requirements of gas-fired power plants depend heavily on their operating time, which in turn depends on their position in the merit order

Profitability of gas-fired power plants in 2035

in CHF_{2024} /MWh (real terms)

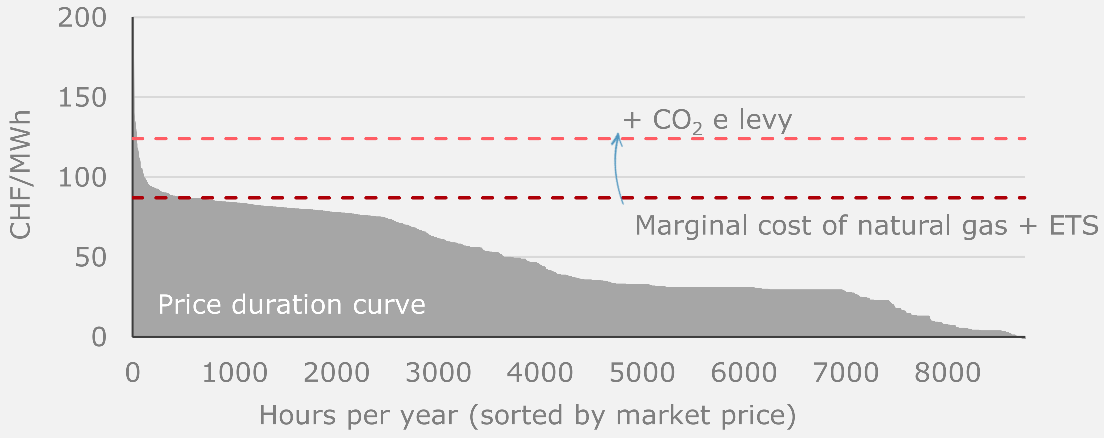


- The double burden of the ETS and the CO_2 levy leads to higher marginal costs and thereby fewer full-load hours. This drives up the levelised cost of electricity. Although average market revenues per MWh also rise, as the plant only operates during hours with very high market prices, the total subsidy requirement increases sharply.
- Plants with very high marginal costs never operate, effectively becoming like reserve power plants, and generate no market revenue. In this case, the subsidy requirement corresponds to the total cost of the plant.

Why do the operating hours of a technology depend on marginal costs?

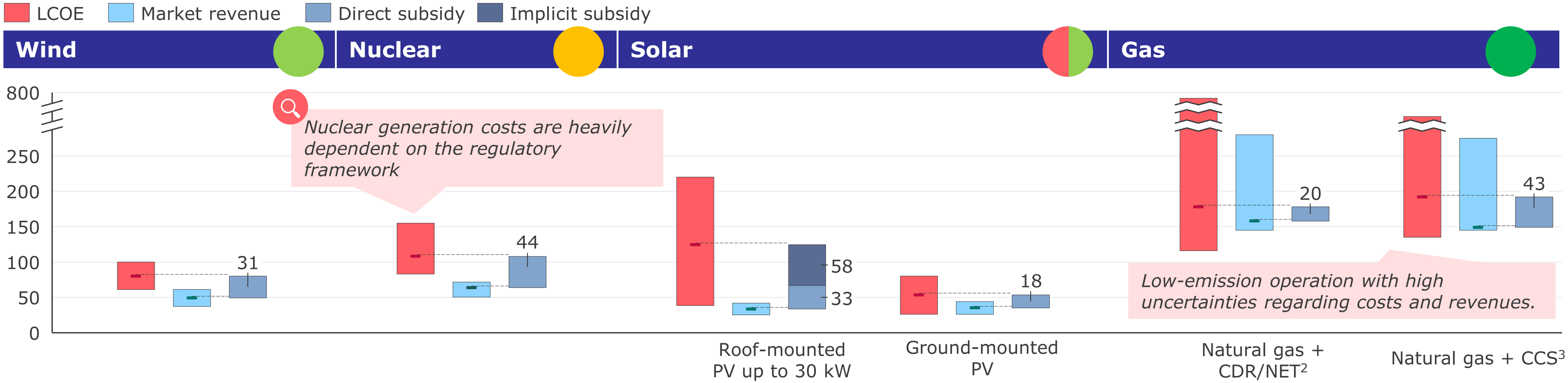
The levelised cost of electricity for a technology depends heavily on the number of full-load hours: the more hours a plant is operated, the better the fixed costs are spread and the lower the average generation costs. Conversely, low utilisation leads to higher levelised costs of electricity.

To determine the expected full-load hours, a plant's marginal costs (the cost of producing an additional kWh of electricity, considering variable costs such as those for fuels and CO_2 emissions) can be compared with hourly electricity market prices. In this case, hourly market prices over a year, sorted by market price level, known as the price duration curve. The plant generates electricity during the hours when the market price exceeds the marginal costs. If marginal costs increase, for example through a CO_2 levy, the full-load hours decrease, and the electricity generation costs rise correspondingly.



By 2050, generation costs will fall due to learning effects. New nuclear power plants may become an option while for gas, the focus will be on low-emission operation

Levelised cost of electricity and revenue, in CHF_{2024} /MWh real[1]



How do our cost assumptions for nuclear power compare with those of current projects?
We have derived the costs for new nuclear power plants from global experience with the reactor type assumed here, the AP 1000. This is based on experience at Vogtle (USA) and analyses by MIT. Compared to Flamanville (FR), we achieve construction costs (OCC) that are around 10% lower per kW of capacity. At Flamanville 3, major delays also increased interest costs. There, the total construction period was 17 years while our assumption for Switzerland is 10 years (including site preparation). Overall, the levelised cost of electricity is around 20% lower than that of Flamanville 3, calculated in each case with a 5% real WACC.

Should we expect changes in usage by 2050?
Our modelling of the development of the Swiss electricity market shows that the number of hours with very low or even negative prices will start to decline again from the 2040s onwards. This is due in part to increased flexibility, such as battery storage and controllable demand, as well as to a general rise in demand. As a result, the operating hours of nuclear power plants are not expected to decline heavily, and cannibalisation between wind and PV will increase only marginally. Furthermore, it is important to understand that curtailing or shutting down generation when prices are low or negative – that is, below the marginal costs of the respective technology – can only improve economic efficiency.

1) Assumed weighted average cost of capital (WACC) rates: wind 4%, nuclear 5%, rooftop PV <100kW 3.5%, other PV 4%, gas 4%; 2) Combustion of imported fossil methane and offsetting the associated emissions with carbon dioxide removal (CDR) certificates from negative emissions technologies (NET); 3) Carbon capture and storage: capture and storage of CO_2 emissions

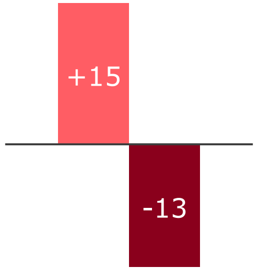
Deep Dive: Costs for new nuclear power plants are strongly influenced by regulatory and political factors. A clear strategy with state risk-sharing is needed

<u>Sensitivity of nuclear electricity generation costs</u>, in CHF_{2024} /MWh (real terms)

Cost of capital (WACC)

+ 1%

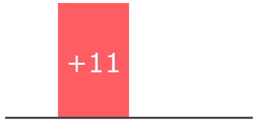
- 1%



- The weighted average cost of capital (WACC) has the greatest influence on total costs due to the long period over which capital is tied up.
- The WACC is critically dependent on which risks are borne by the investors, and which are borne by the state. The higher the perceived investment risk, the higher the return requirements of the investors. A well-structured subsidy scheme can help to lower the WACC and thus reduce costs.

Design adjustments during construction[1]

+ 1,150 CHF/MW

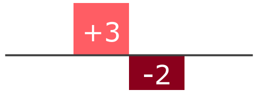


- Regulatory changes, for example due to stricter safety requirements, have a particularly significant impact during the construction phase: planning halts and delays cause commissioning to be postponed, construction and financing costs rise, and the economic viability of the overall project is compromised.
- Such changes represent a risk that is difficult for investors to accept. To reduce the likelihood and impact of design modifications, plants under construction should be assessed in the same way as existing plants.

Construction period

+ 1 year

- 1 year



- Delays, for example due to challenges in the approval process during the construction phase, increase costs. A delay of 6 years, as was the case with Flamanville in France, could increase production costs by 18 CHF/MWh.

For new nuclear power plants, it is necessary to assume state-driven political-regulatory risks*, such as subsequent changes to safety and environmental requirements during the planning and construction phases. The challenge with these risks is that, while they are imposed through political decisions, the resulting financial consequences – in the form of higher capital and construction costs – must be borne by the investors. That is, unless the state assumes the risk.*

1) The reference assumption for nuclear energy generation costs already includes design adjustments prior to the start of construction as well as minor subsequent adjustments. The adjustments shown here relate to substantial, major changes to the power plant design after construction has begun.

In-depth analysis: Switzerland's location increases costs across all technologies, but regulatory changes could reduce the 'Swiss premium'

Factors driving higher costs in Switzerland compared to other countries

	Wind	**Nuclear**	**Solar**	**Gas**
Cost environment *Given*	**Labour costs and the general price level are higher in Switzerland**			
Geography *Given*	**Geography and land availability lead to higher costs**			
	• Small wind farms limit economies of scale • Logistics are more difficult in alpine terrain	• Hardly any economies of scale (limited number of units)	• Open space: limited land availability and high land prices, challenging topography in mountainous areas	Complete dependence on other countries for fuel and CO_2-storage
Regulation ***Partially modifiable***	**Swiss Finish**			
	• Requirements for wind measurement • Historically long and expensive approval process	• Lengthy approval process, including a referendum • Adoption of standard reactor design hampered by Swiss regulations	• Comprehensive requirements and building regulations for ground-mounted PV • Severe restrictions on agricultural land[1]	• Double tax burden: CO_2 levy & ETS system • Stipulated waste heat utilisation may incur additional costs

1) Installations must not impair agricultural production

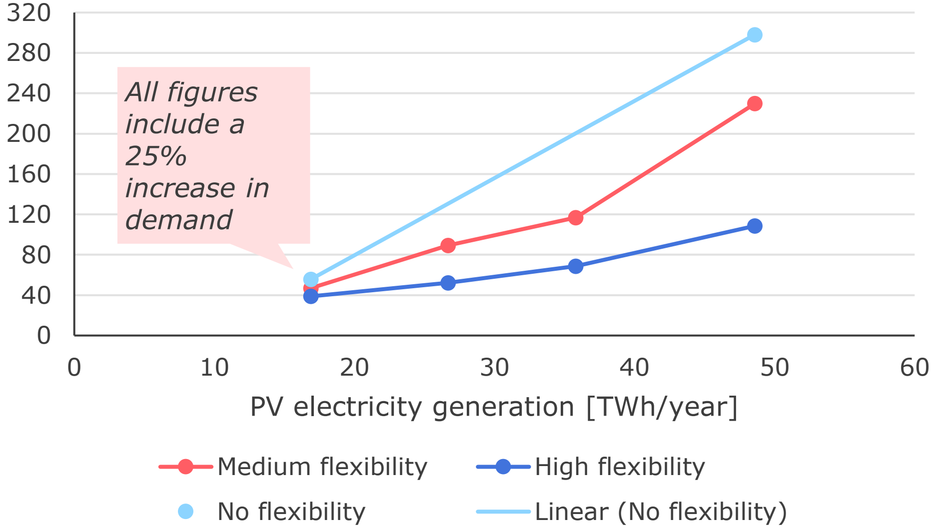
The costs of grid expansion, driven in part by rising demand, could increase with the expansion of generation capacity, especially with a high proportion of decentralised PV

Based on analyses with
FEN of ETH Zürich

Grid integration and grid expansion requirements

	Wind	Nuclear	Solar	Gas
Grid integration	Less impact on the distribution network, as connection is at a higher grid level	Preference is given to existing power plant sites, ensuring grid integration	Grid expansion or other measures (see below) required with more rooftop	Connection at the extra-high voltage level limits potential sites

Annualised grid expansion costs in CHF million/year
Grid levels 4–7, analysis by EBP and FEN in Zurich



- *Rising demand (+25% in winter) and low PV expansion trigger comparatively low grid expansion (costs approx. CHF 40–50 million/year)*
- *As PV capacity increases, grid expansion costs rise (assuming constant demand). Decentralised flexibility can significantly reduce costs. For example, in the case of very high PV penetration this can be by a factor of 3*
- *Flexibility measures for grid integration that are considered here:*
  (i) Feed-in limitation to reduce power peaks (low energy losses, e.g., max. 3% when limited to 70%)
  ii) Flexible demand and batteries (where beneficial to the grid, price signals are important)
  iii) Additional grid expansion as an expensive option.

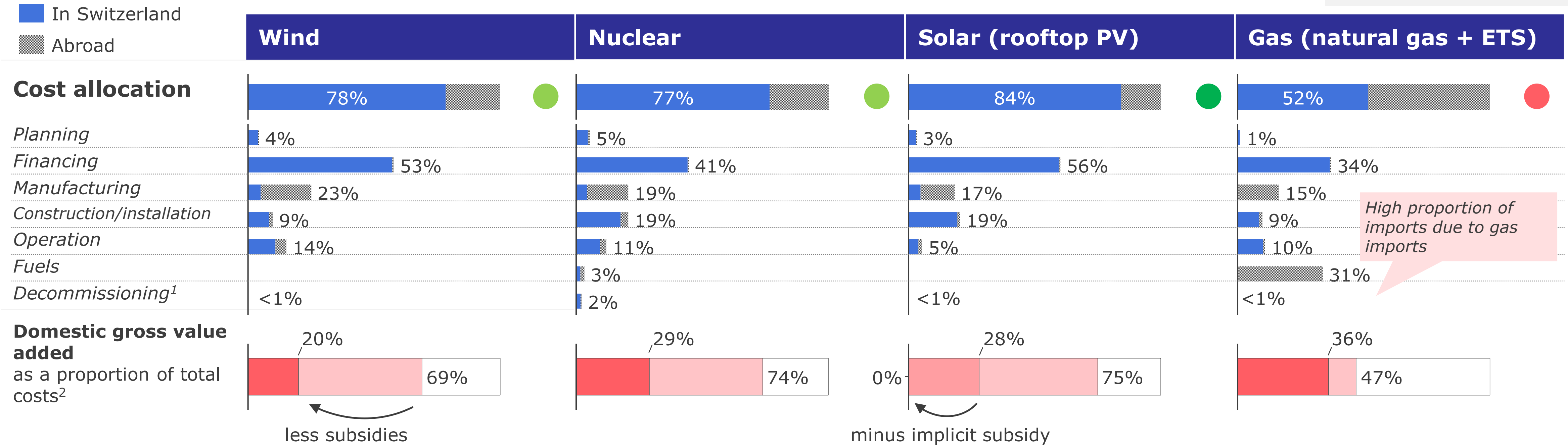
Analyses conducted jointly with FEN Zurich and EBP (see p.45 for further details)

***Inaccurate feed-in forecasts increase the current demand for balancing energy**. However, we assume that more flexibility, improved forecasts and adjustments to market design will correct current inefficiencies.*

Rooftop PV accounts for the highest proportion of domestic costs, while a large proportion of expenditure on gas-fired power plants flows abroad due to fuel imports

Based on analyses using Swiss Economics

Cost allocation and domestic gross value added from investments in electricity generation



How was gross value added calculated?

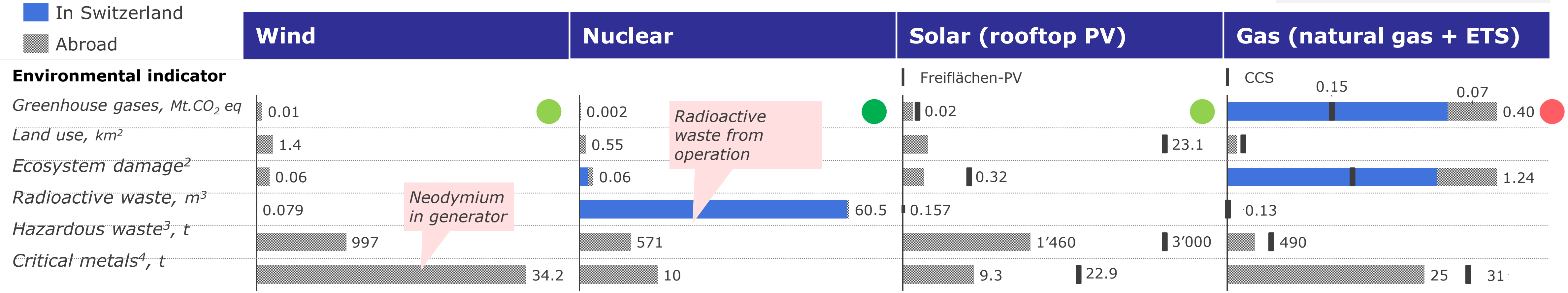
The blue bars show what proportion of the costs are incurred in Switzerland and how much flows abroad. For example, of the total costs of a 5 MW wind turbine (around CHF 32 million), 78% of expenditure is incurred in Switzerland. However, imported intermediate inputs (e.g., components) result in a lower domestic value added of 69% (around CHF 22 million) (red bar). As part of this value added is financed by subsidies (e.g., grid surcharge), it does not represent purely additional value added. This is because the funds used displace consumption – and thus value added – elsewhere. If the total subsidies are deducted from the value added, the wind turbine retains around CHF 7 million in market-based value added, which corresponds to a domestic value-added share of around 20% of the total costs. To determine the exact difference, the value added from the lost consumption would also need to be calculated, but this was not possible within the scope of this analysis. The actual domestic value added therefore lies between the two figures – with and without the deduction of the subsidy.

1) Decommissioning costs for wind, solar and gas are included in the total costs, but are not paid annually, as is the case with nuclear power. Instead, they are incurred as a one-off expense at the end of the plant's lifespan. They are negligible compared to the decommissioning costs of nuclear power; 2) To calculate domestic value added, all costs incurred within Switzerland are broken down by cost type and assigned an appropriate multiplier. This is important because not all expenditure generates the same amount of value added in Switzerland. Value added that results from the consumption of the electricity that is produced is not considered

Every technology has specific environmental impacts: CO_2-e emissions from gas, radioactive waste from nuclear energy, and hazardous waste and land use from solar and wind power

Environmental impacts, per TWh in 2035 (2050 for nuclear)[1]

Based on analyses with PSI



Explanatory notes

Wind: The impacts of wind power occur almost exclusively along the supply chain and are therefore located abroad. As a result, greenhouse gas (GHG) emissions, for example, are low but not zero. Impacts on the landscape, such as visual intrusion, are not considered.

Nuclear: The operation of nuclear power plants generates radioactive waste, which must be stored in deep geological repositories. All other indicators are comparatively low. For example, nuclear power has the lowest GHG emissions.

Solar (rooftop PV): The impacts of rooftop PV occur almost exclusively along the supply chain and are therefore located abroad. Ground-mounted PV requires a significant amount of domestic land. It also generates a large amount of hazardous waste in the supply chain, due to the copper required for cabling and transformation.

Gas (natural gas + ETS): Gas-fired power plants have high domestic and foreign GHG emissions. They also contribute to ecosystem damage. The environmental impact of alternative fuels is included in PSI's environmental analysis[6].

How can environmental indicators be interpreted and compared?

The indicators are based on life-cycle analyses per TWh and measure different environmental impacts that are neither directly comparable nor quantifiable. The results depend heavily on assumptions regarding service life and full-load hours of the reference plants[5]. A low value for a single indicator does not, therefore, imply the general environmental superiority of a technology. Such an assessment would require normative weightings, which have been deliberately omitted here. Consequently, the comparison is limited to the greenhouse gas indicator.

1) Environmental impact indicators are available from 2025 to 2050; figures for 2035 are presented for comparability with nuclear energy. The values typically show a slight decrease by 2050, driven mainly by global decarbonisation. The detailed report also includes results for battery storage; 2) Measured in terms of species-years lost per TWh, species-loss*a/TWh; 3) Hazardous waste comprises waste that must be stored in underground repositories due to its hazardous properties; 4) Critical metals comprise cobalt, lithium, neodymium and nickel; 5) The same reference plants were used as in other parts of the technology comparison; 6) The analysis of natural gas in combination with CDRs (carbon dioxide removal certificates) was omitted, as there are significant uncertainties surrounding these certificates and no clear regulatory or methodological guidelines for such certificates are currently available.

03 Scenario analysis

The aim is to establish a secure, affordable and low-emission energy supply (I/II)

Two realistic technology mix options for future winter electricity supply were used, from a wide range of possible scenarios: ‘Renewables + Gas’ focuses on renewable energies and gas, while ‘Coexistence’ focuses on the interaction of nuclear energy with other technologies.

- The analysis is based on an increase in demand. By 2050, demand is expected to grow by around 25% or 9 TWh in the winter half-year, compared to 2025.
- To meet this growth in demand and replace existing nuclear power plants, both scenarios require the rapid expansion of wind and PV, supplemented by preparations for gas power plants and, where necessary, new nuclear power plants.

Total costs rise in both scenarios. In the ‘Renewables + Gas’ scenario, the cost increase is more pronounced. The grid surcharge can cover the funding requirement, plus the implicit subsidy for rooftop PV.

- In both scenarios, the expansion of electricity generation leads to rising costs. These are higher overall in the ‘Renewables + Gas’ scenario.
- The grid surcharge of 2.3 Rp/kWh can roughly cover the direct subsidies in both scenarios. However, a part of the costs of rooftop PV systems is financed through an implicit, rather than direct, subsidy.
- The long-term operation of existing nuclear power plants reduces costs and is particularly valuable in the event of a delayed expansion of renewables.

Grid expansion costs are higher in the ‘Renewables + Gas’ scenario due to the greater expansion of rooftop PV but are relatively low overall, compared to investments in generation.

- Grid expansion costs driven by PV expansion can be reduced through targeted measures, such as feed-in limits of 70% or 50%, as well as flexible demand.

Technology scenarios: Costs are highest with very high PV expansion. Scenarios focusing on wind or gas are cheaper.

- The range of costs can be seen across the technology scenarios: the ‘PV-focus’ scenario has total costs that are around 50% higher than the ‘Wind-focus’ scenario, and 60% higher costs than the ‘Gas-focus’ scenario.
- The need for subsidies is also significantly higher in the ‘PV-focus’ scenario than in the other technology scenarios considered.

The aim is to establish a secure, affordable and low-emission energy supply (II/II)

There is limited potential to further increase winter electricity generation from hydropower. Imports and gas-fired power plants are essential for meeting demand, particularly during the meteorological winter from December to February.

- Existing hydro storage facilities are already being operated at optimal levels. Additional winter generation – through dam height increases or new facilities – is only possible to a limited extent and is relatively expensive.
- During the meteorological winter, non-flexible generation is low; hydropower cannot always meet demand and must be supplemented by gas or imports.

Imports remain a key pillar of electricity generation and primary energy. However, the majority of electricity demand is met by domestic generation, thereby also reducing dependence on primary energy imports.

- While the majority of electricity demand can be met by domestic generation, electricity exchange with neighbouring countries also plays an important role in all scenarios and remains central to security of supply.
- Imports and exports are possible in the scenarios, but developments in neighbouring countries are uncertain.
- Additional reserve power plants are planned to cover worst-case scenarios.
- Scenarios are generally robust against either lower or higher demand. The expansion of gas, and potentially wind and PV, is possible in the short term.
- The net import requirement for energy sources is falling significantly. The lack of gas storage facilities poses a challenge for gas-fired power plants.

Domestic value added and employment sit at a similar level in both scenarios.

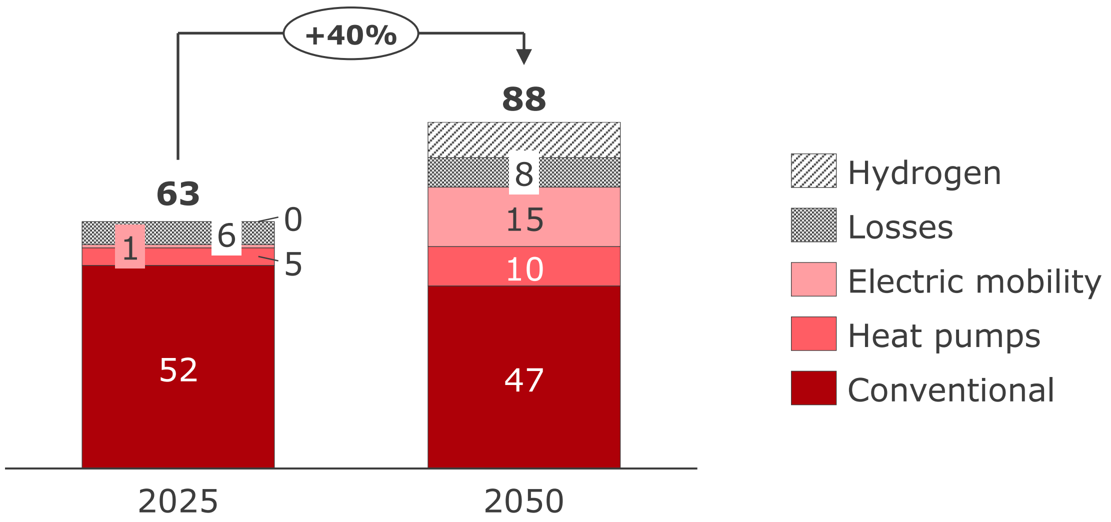
- In both scenarios, the domestic value-added share is around 65% while there are approx. 15,000 full-time jobs per year. In the ‘Coexistence’ scenario, long-term operation is required to maintain expertise.

Greenhouse gas emissions fall across the entire system due to electrification, which in turn increases electricity demand.

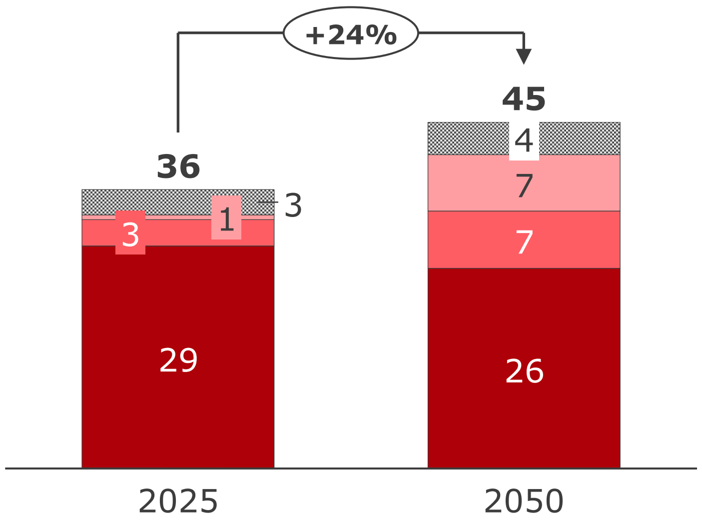
- Gas-fired power plants increase greenhouse gas emissions but can improve security of supply and therefore contribute to electrification and decarbonisation.
- New gas-fired power plants in Switzerland are more efficient than existing ones. Solutions for low-emission operation are possible by 2050, but the availability of these solutions and the associated costs are highly uncertain.

The scenario analysis is based on an increase in demand in the winter half-year of 25% or 9 TWh by 2050, compared to 2025. Demand is the same in both scenarios

Annual electricity demand, TWh



Winter electricity demand, TWh



How will demand develop over the course of the year?
Fundamentally, demand trends are subject to uncertainties – how rapidly is electrification progressing, how many data centres will be built? In the following analyses, we assume a total increase in demand of 16 TWh (excluding hydrogen) by 2050, or 25%. Electrolysers could be used to produce hydrogen in summer, to utilise summer surpluses, but this development is particularly uncertain.

Future per capita consumption will fall due to efficiency improvements in industry, commerce, retail, services and the private sector. A reduction of around 20–25% is assumed here. Conversely, demand is increasing, driven for example by data centres and population growth. To decarbonise the heating sector, 10 TWh of demand from large and small heat pumps is assumed. Electromobility leads to an increase in demand of around 14 TWh.

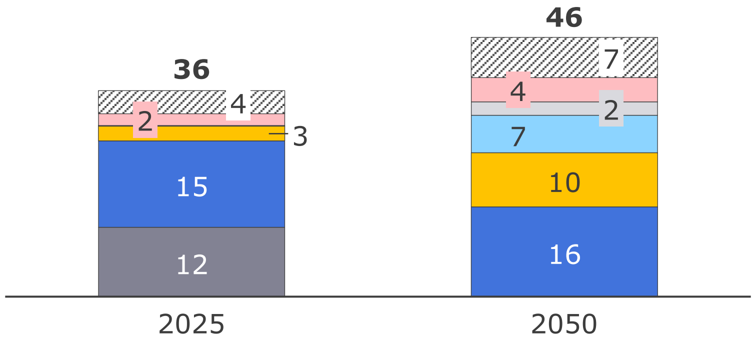
How does demand develop in winter?
60% of the increase in demand (excluding hydrogen) occurs in winter – an increase of 9 TWh, to around 45 TWh in 2050.

The main drivers of the stronger growth in winter are heat pumps, around 70% of which are used in winter, and conventional demand, which already has a winter-heavy profile today.

Two realistic technology mix options are considered: one focuses on renewable energy and gas, the other on the coexistence of nuclear energy with other technologies

Electricity generation in the winter half-year in TWh

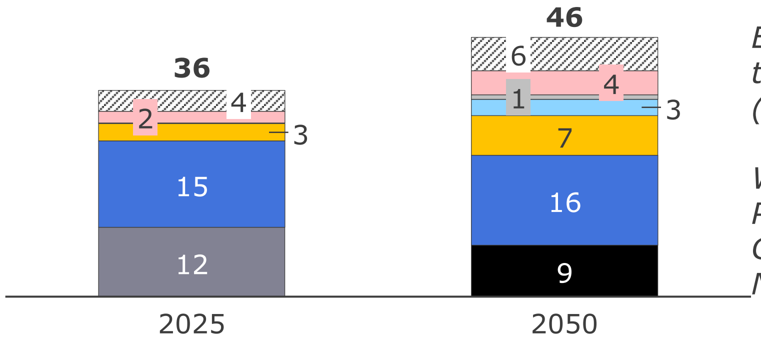
Renewables + Gas



Expansion of the four technologies (compared to 2025):

Wind: +5.8 GW
PV: + 25.8 GW
Gas: +1.2 GW
Nuclear: no expansion

Coexistence *(renewables + gas + nuclear)*



Expansion of the four technologies (compared to 2025):

Wind: +2.5 GW
PV: +16.8 GW
Gas: +0.4 GW
Nuclear: +2.2 GW

Import | Others | New gas-fired power stations | Wind | PV | Hydro | Nuclear energy stock | New nuclear energy

- This is based on the current energy strategy, with a focus on renewable energies. The framework decree's target for 2045 is met (45 TWh of new renewables, target for 2035 unrealistic)
- There is no long-term operation of existing nuclear power plants. The scenario assumes a world in which nuclear energy is less socially desirable (see slide 41 for long-term operation sensitivity)
- The scenario requires a significant acceleration in the construction of wind power, from 50 to approx. 1,000–1,300 wind turbines
- Gas-fired power plants operating on the market[1] are also needed

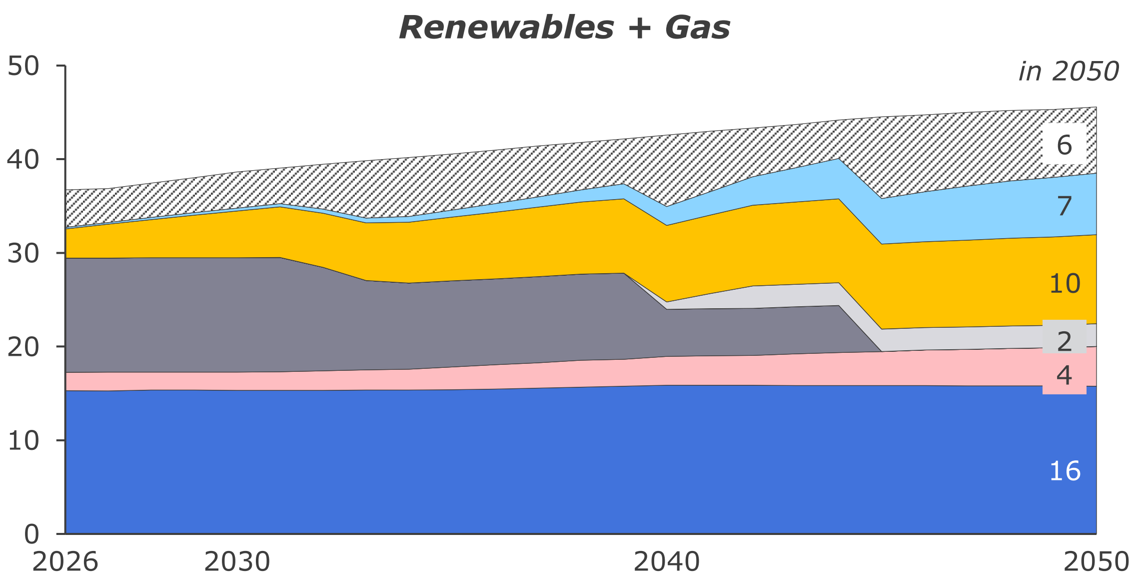
- New nuclear power plants are constructed, to further diversify the electricity mix. 2 AP1000s (each ~1,100 MWe) are constructed by 2050 and broader acceptance of nuclear energy enables the operating life of existing plants to be extended until then
- Expansion of renewables (wind and PV) continues, though at a slower pace than in 'Renewables + Gas'. There are approx. 400–500 wind turbines, while growth in rooftop PV is slower than today
- In addition, there is a low capacity of gas-fired power plants operating on the market

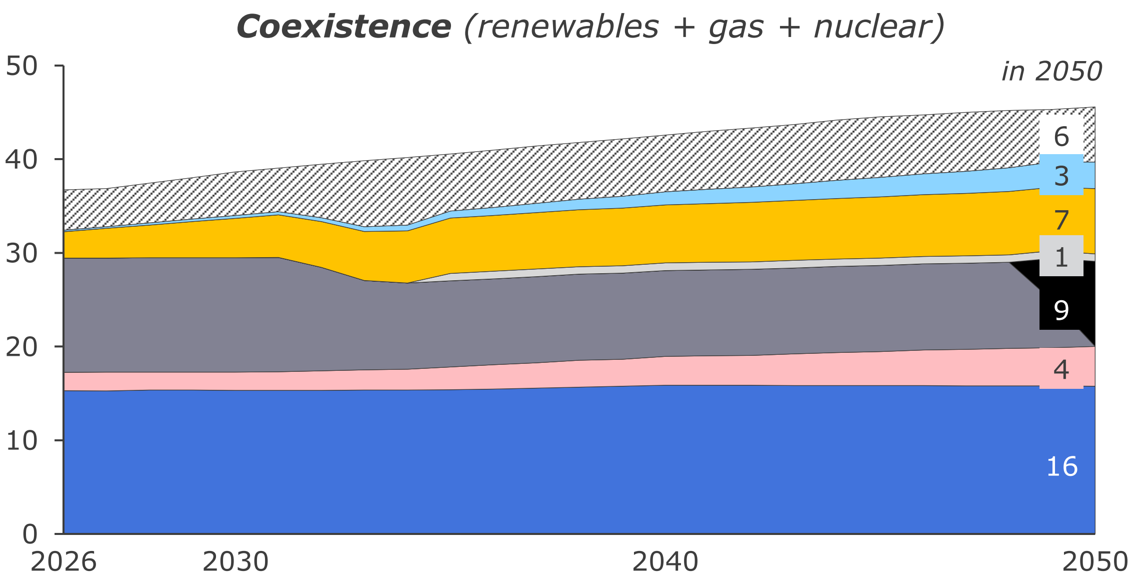
Underlying assumptions: *Exchange (imports and exports) with neighbouring countries is possible. Both scenarios have the potential to cover demand with domestic electricity generation, apart from 5 TWh of imports in winter. Higher imports are a market-based decision to forego domestic (gas) power plant operations and instead import more cheaply. For situations of scarcity, the existence of reserve power plants (around 1.4 GW in both scenarios, based on ElCom analyses) is assumed. This is not modelled in detail here.*

1) Fuel and operating hours of gas-fired power stations are uncertain; here and below, 2,000 full-load hours and costs of natural gas + CDR are assumed on a market basis; for other fuels, these values differ

There needs to be rapid expansion of wind and solar power, plus preparations for gas and, if necessary, new nuclear power plants, to meet growing demand and replace existing nuclear power plants

Electricity generation in winter in TWh





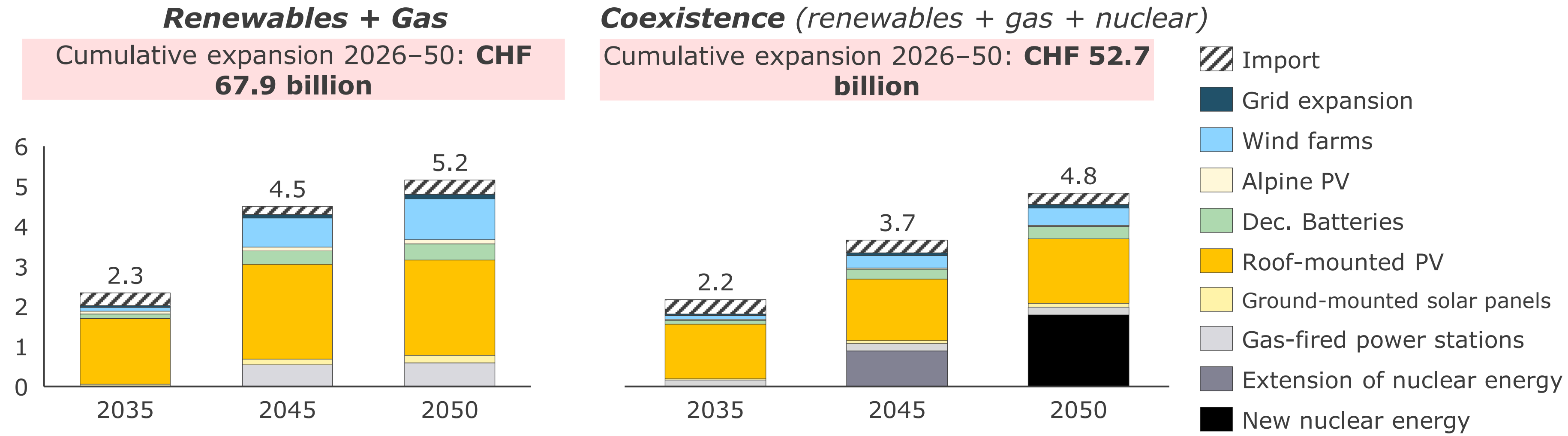
Import | Wind | PV | New gas-fired power stations | New nuclear energy | Nuclear energy stock | Others | Hydro

What steps need to be taken today?
In the 'Renewables + Gas' scenario, the expansion of wind farms must be significantly accelerated. To achieve this, the acceleration decree must be implemented, more suitable areas designated and nationwide planning strengthened. The expansion of PV will be slightly reduced, with a focus on grid integration. Suitable areas will be designated for ground-mounted installations. Gas-fired power plants must be made possible by adapting the regulatory framework (auctions, CO_2 levy and waste heat utilisation), to achieve expansion from 2040 onwards.

What steps must be taken today?
In the 'Coexistence' scenario, the extension of the operating life of existing nuclear power plants and preparations for new nuclear power plants must be initiated today.
The expansion of wind farms must be accelerated using the same measures as in the 'Renewables + Gas' scenario. PV subsidies will be slightly reduced, meaning that the rate of PV expansion will slow down in the 2030s compared to today. Gas-fired power plants must be made possible, to achieve expansion from 2035 onwards.

In both scenarios, the expansion of electricity generation leads to rising costs. In the 'Renewables + Gas' scenario, these costs are higher

Annual costs for new plants and grid expansion in CHF billion



How are the annual costs calculated?

- *The calculation considers the annual costs of each plant. CAPEX is allocated over the entire lifetime, as with production costs, and annual OPEX is added. Construction and decommissioning are included.*
- *This yields annualised electricity generation costs, which can then be compared year on year.*
- *A comparison of investments would be misleading, as they are incurred in individual years, but plants operate for longer.*
- *For rooftop PV systems, different plant sizes are assumed: for each of the categories >30 kW, 30–100 kW and >100 kW, the potential and current installed capacity were assessed. The difference between these figures represents the remaining potential. New installations are accounted for proportionally based on the remaining potential.*
- *The focus is on the costs of the technologies under consideration – wind, PV, nuclear and gas – as well as the extension of the operating life of existing nuclear power plants beyond 60 years. Costs for maintaining the existing grid, existing generation plants and other facilities are the same in both scenarios and are not shown here. Import costs are not included in the cumulative expansion costs (imports cumulated in 'Renewables + Gas': CHF 7.1 billion, Coexistence: CHF 7.3 billion).*

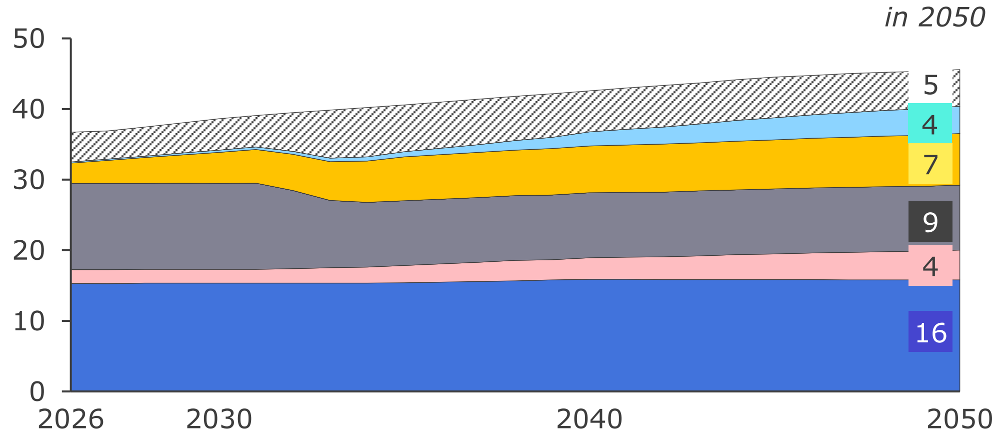
Key findings

- Renewables are more expensive than 'Coexistence', at , at a cumulative cost of CHF 67.9 billion vs. CHF 52.7 billion (cumulative costs for expansion 2026–2050).
- The largest cost drivers are PV and new nuclear power. Long-term operation (LTO) of nuclear power plants offers cost advantages in a 'Coexistence' scenario. See the next slide for details on LTO in the 'Renewables + Gas' scenario.
- Renewables are slightly more expensive, particularly in the early years. From 2050 onwards, annual costs are roughly comparable.
- The additional costs for grid expansion are comparatively minor. Costs for decentralised batteries are also incurred.

Deep Dive: Extending the operational life of existing nuclear power plants enables cost reductions, even in the 'Renewables + Gas' scenario. This is particularly valuable if the expansion of renewables is delayed

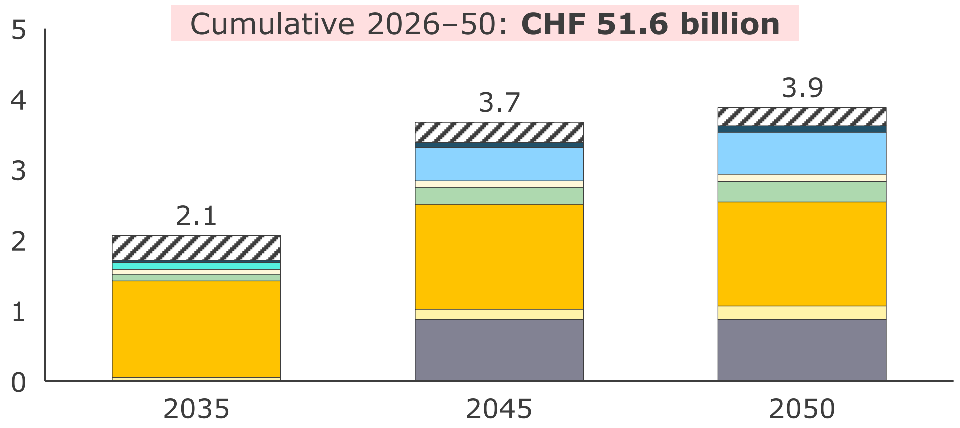
Electricity generation in the winter half-year in TWh

Renewables + Gas with long-term operation



Annual costs for new plants and grid expansion in CHF billion

Renewables + Gas with long-term operation



Import | Wind | PV | New gas-fired power stations | New nuclear energy | Nuclear energy stock | Others | Hydro

- Long-term operation (LTO) of existing nuclear power plants would buy time for the 'Renewables + Gas' scenario, should the roll-out of other technologies (e.g., renewables) be delayed.
- Assuming an operational lifetime of 80 years for the Gösgen and Leibstadt nuclear power plants, it would only be necessary to compensate for the loss of production from Beznau (3 TWh in winter, with decommissioning from 2033 already decided) and for the growth in demand (9 TWh in winter).
- Cumulative costs from 2026 to 2050 would fall from CHF 67.9 billion to CHF 51.6 billion, making costs comparable to the 'Coexistence' scenario.

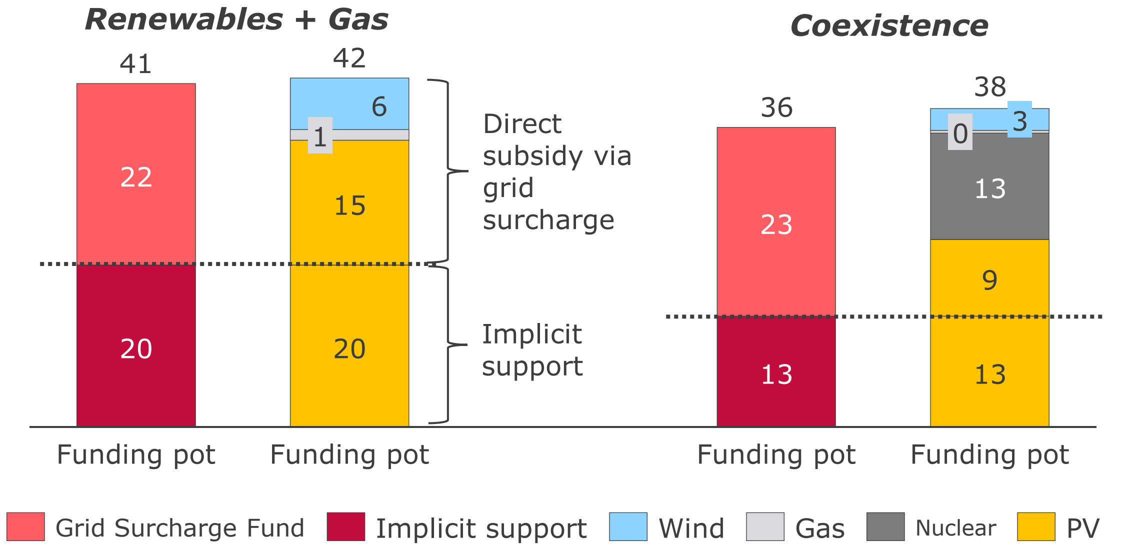
What changes in the 'Renewables + Gas' scenario if a phased decommissioning plan is considered?

- *PV expansion continues at a rapid pace until the mid-2030s and helps to compensate for Beznau's output (decommissioning from 2033). From 2040, PV expansion is significantly delayed compared to the main 'Renewables + Gas' scenario (24 GW in 2050).*
- *Wind expansion also proceeds at a high rate initially, then slows from 2040 (3.4 GW in 2050).*
- *No expansion of gas-fired power plants is needed by 2050.*

The grid surcharge of 2.3 Rp/kWh can roughly cover the direct subsidies in both scenarios, while part of the PV costs are financed through an implicit subsidy

Cumulative subsidy pot and requirements in CHF billion 2026–2050

The scenarios are not directly comparable! Funding is provided upon construction of the facilities, but the remaining lifespans vary across the scenarios



Key findings

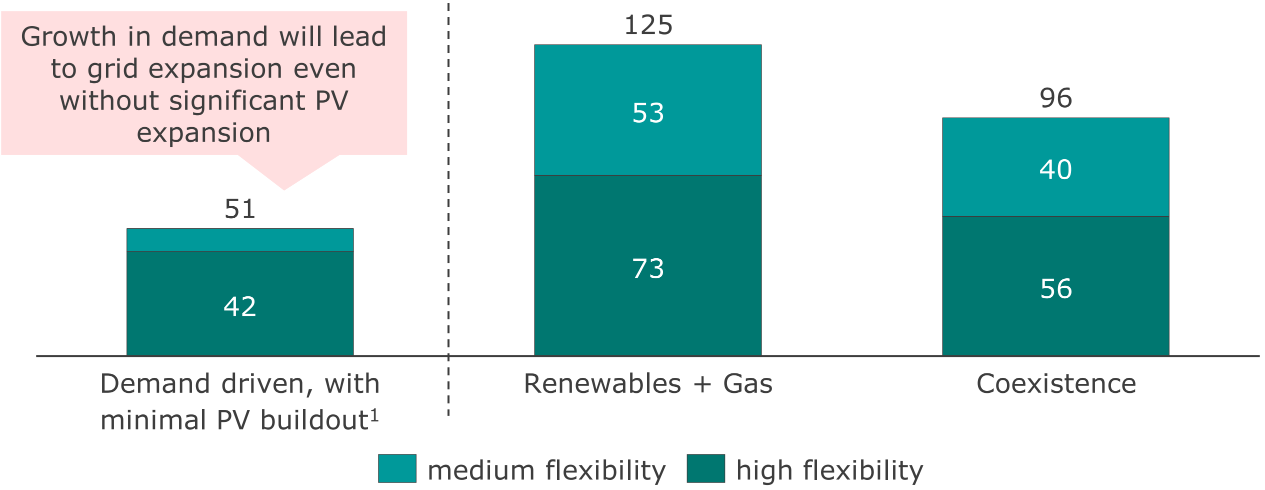
- **The grid surcharge fund is sufficient to cover direct subsidies in both scenarios.** Implicit subsidies are not included.
- ‘Renewables + Gas’: CHF 22.6 billion in direct subsidies (excluding existing commitments), plus CHF 19.6 billion in implicit subsidies.
- ‘Coexistence’: CHF 25.1 billion in direct subsidies (excluding existing commitments), plus CHF 13.4 billion in implicit subsidies.
- All technologies receive their full subsidy upon construction. The subsidies for nuclear power plants in the ‘Coexistence’ scenario are therefore incurred before 2050, even if they continue to generate electricity for ~60 years thereafter.
- Funding requirements for long-term storage and additional risk assumptions are not included in the analysis.
- Funding requirements would significantly exceed the funding pot without implicit support and funding would need to be increased to 3.1 to 3.7 Rp/kWh.
- Grid surcharge currently applies to renewables. For nuclear and gas-fired power stations, the fund would need to be extended to cover these or a new surcharge introduced.

How do we calculate the subsidy pot and funding requirements?

- *The figure shows the direct funding (based on winter funding requirements) as an investment cost contribution, aggregated from 2026 to 2050. Funding is incurred in the year of construction. This means that the investment cost contribution for nuclear energy is fully included, despite a longer operating life beyond 2050.*
- *The funding requirement is additionally partially covered by the implicit subsidy for rooftop PV, which can reduce rooftop PV’s grid cost contribution through self-consumption. The implicit subsidy is borne by other end customers through higher grid charges.*
- *The subsidy pot consists of the grid surcharge and the implicit subsidy. The volume of the grid surcharge will rise from around CHF 1.2 billion per year today to around CHF 1.5 billion per year in 2050, due to higher future demand. In addition, the reimbursement for energy-intensive industry is considered, as is the fact that no grid surcharges are levied on self-consumed electricity from rooftop PV systems.*
- *The grid surcharge fund has existing commitments of around CHF 10 billion, for example payments that have already been committed to hydropower, which have already been deducted from the analysis presented.*

Grid expansion costs are higher in the 'Renewables + Gas' scenario due to the increased installation of rooftop PV, but are generally relatively low compared to the investments in generation

Annualised grid expansion costs in Switzerland for the two scenarios, 2050 in CHF million/year



	Feed-in limit	Demand flexibility: Electric mobility	Demand flexibility: Heat pumps	Battery storage
Medium flexibility	70% (at the property connection)	20% reduction in the evening	No flexibility	0.8 kW BESS per kWp PV (for new installations)
High flexibility	50% (at the property connection)	50% reduction in the evening	Reduction between 6 pm and 10 pm	1 kW BESS per kWp PV (for new installations)

Key findings

- Demand-driven grid expansion leads to costs in both scenarios. Even without PV expansion, this results in costs of CHF 40–50 million per year (depending on the availability of flexibility).
- The integration of PV feed-in peaks may lead to additional costs.
- The need for grid expansion can be reduced through various measures: i) limiting PV feed-in peaks, ii) increasing the flexibility of existing demand, and iii) decentralised battery storage. Without these measures, grid expansion is much more expensive (see p. 32 Grid integration of PV).
- We consider two options, both with flexibility measures (see table). These flexibility measures are factored into the overall cost analysis.
- In the 'Renewables + Gas' scenario, the grid must be expanded more extensively, to integrate higher PV feed-in peaks, than in the 'Coexistence' scenario.

The evolution of balancing energy costs through to 2050 is not considered in the assumptions, as it is assumed that more flexibility in the future, improved forecasts and adjustments to market design will correct current inefficiencies.

1) PV expansion by 2050: +7 GW, i.e. an annual expansion of around 290 MW (which corresponds to only around 15–20% of the expansion seen in recent years)

The range of costs can be seen across the ‘technology scenarios’: a scenario with a high proportion of PV is more expensive than one with a high proportion of wind or gas

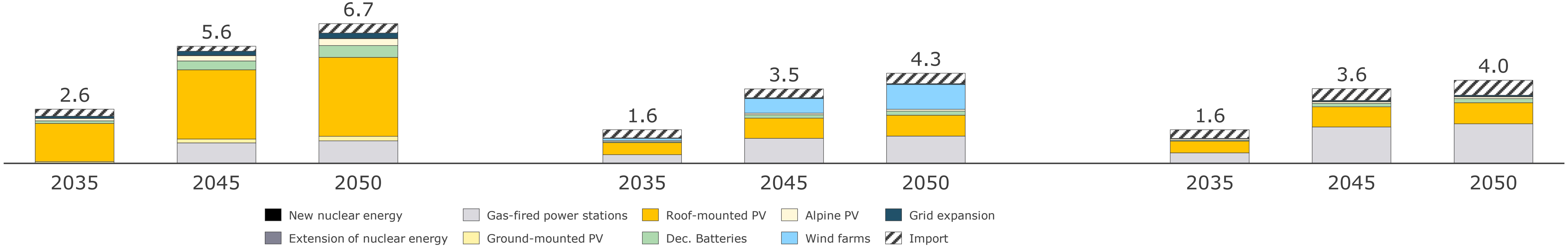
Annual costs for new plants, grid expansion and imports in CHF billion/year

Considerations: In average years, all scenarios can cover electricity demand in the winter half-year with up to 5 TWh of imports

PV-focus
Cumulative expansion 2026–50: **CHF 80.4 billion**
+ CHF 8 billion in imports

Wind-focus
Cumulative expansion 2026–50: **CHF 44.7 billion**
+ CHF 10.2 billion imports

Gas-focus[1]
Cumulative expansion 2026–50: **CHF 41.5 billion**
+ CHF 11.6 billion imports

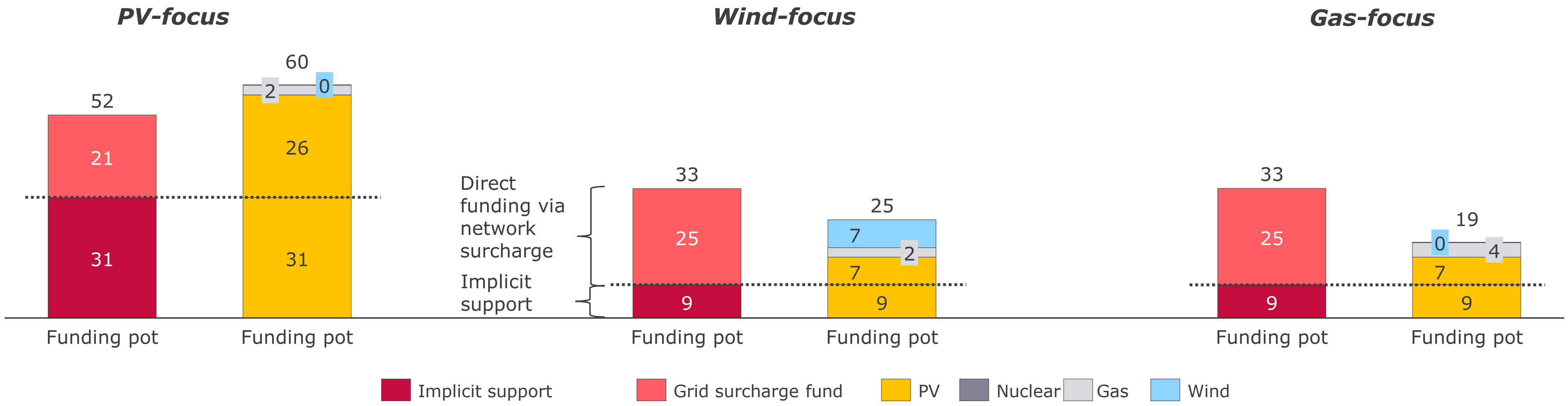


	PV-focus	Wind-focus	Gas-focus
Key findings	• A scenario with a high proportion of PV is very expensive. This is because small, decentralised PV plants, decentralised flexibility (batteries) and grid expansion all lead to additional costs.	• A scenario with a high share of wind would be more cost-effective than the two synthesis scenarios (‘Renewables + Gas’, ‘Coexistence’)	• The most cost-effective scenario involves many gas-fired power plants. A key prerequisite is sufficient export capacity in neighbouring countries. If this is the case, cheap imports can be utilised and domestic gas-fired operating hours kept low. • However, costs are highly uncertain: if import capacity is low, total costs rise
Capacity in 2050[2]	50 GW PV (+40 GW compared to today) 0.3 GW wind 2.2 GW gas 0 GW nuclear	17 GW PV (+7 GW compared to today) 8 GW wind 2.6 GW gas 0 GW nuclear	17 GW PV (+7 GW compared to today) 0.3 GW wind 3.8 GW gas 0 GW nuclear

1) A key challenge in this scenario is ensuring a secure supply of gas, even in critical times. There are currently no large gas storage facilities in Switzerland (see Slide 49); 2) Hydro and other sources are the same in all scenarios, not shown here; fuel and operating hours of gas-fired power stations are uncertain; here and below, 2,000 full-load hours and costs of natural gas + CDR are assumed on a market basis; for other fuels, these values differ

In the scenario with a high proportion of PV, the funding need is also significantly higher than in the scenarios with a high proportion of wind power or gas-fired power plants plus imports

Cumulative funding requirements in CHF billion 2026–2050



Key findings

- The ‘Gas-focus’ and ‘Wind-focus’ scenarios require significantly less funding than the ‘PV-focus’ technology scenario or the ‘Renewables + Gas’ and ‘Coexistence’ synthesis scenarios.
- In both the gas and wind scenarios, the grid surcharge fund would be able to cover the funding requirements, even if the implicit subsidies were removed. In the ‘Gas-focus’ scenario, the grid surcharge – and thus the burden on end consumers – could be reduced. ‘PV-focus’ has the highest funding requirement.

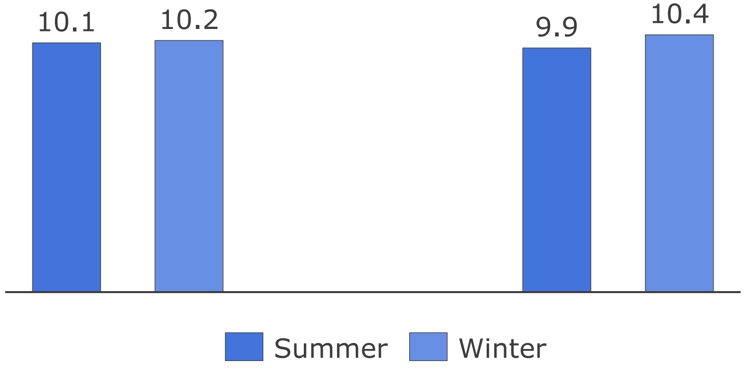
For a brief explanation of the methodology, see slide 37

Hydropower is already operated with a focus on winter: the scope for increasing seasonal storage capacity is limited

Winter and summer electricity generation from Swiss hydropower in TWh

Market-optimised hydro utilisation (full import capacity)

Hydro deployment for security of supply* (no imports)



Based on analyses with
FEN of ETH Zürich

Key findings

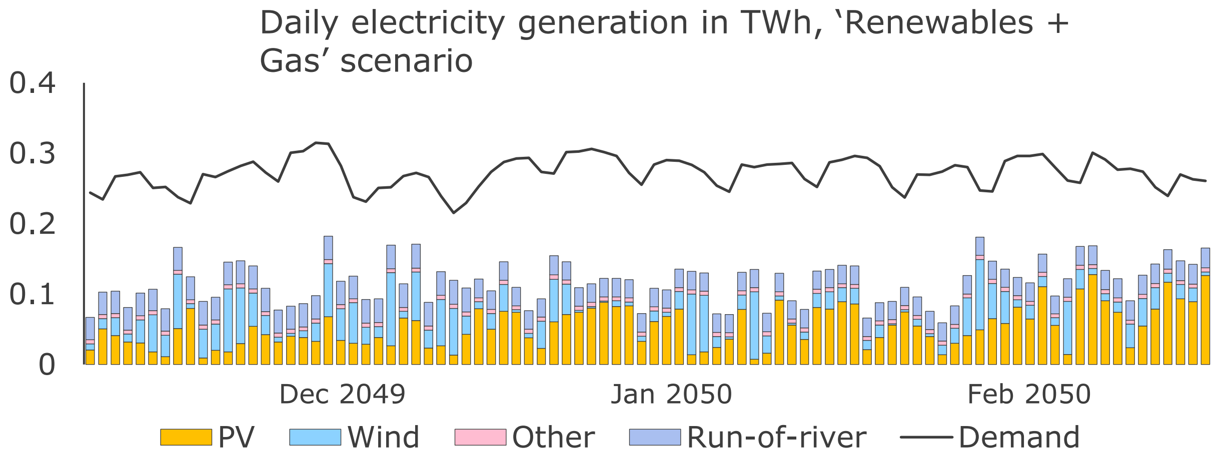
- There is limited scope to shift electricity generation from Swiss hydropower further into the winter months:
  - Hydropower already leans heavily towards winter in today's market-optimised operation approach, and
  - Even in the event of a supply shortage in winter, there is limited scope for further seasonal shifting.
- The growth potential for hydroelectric power generation is limited.
- Pumped-storage power plants are not seasonal storage facilities. Their operational profiles are typically daily or weekly.
- Hydropower can distribute stored energy throughout the winter:
  - Whether generation happens during the meteorological winter or the winter half-year has limited relevance.
  - This is a specific advantage of the Swiss system.
- Batteries play no role in seasonal storage.

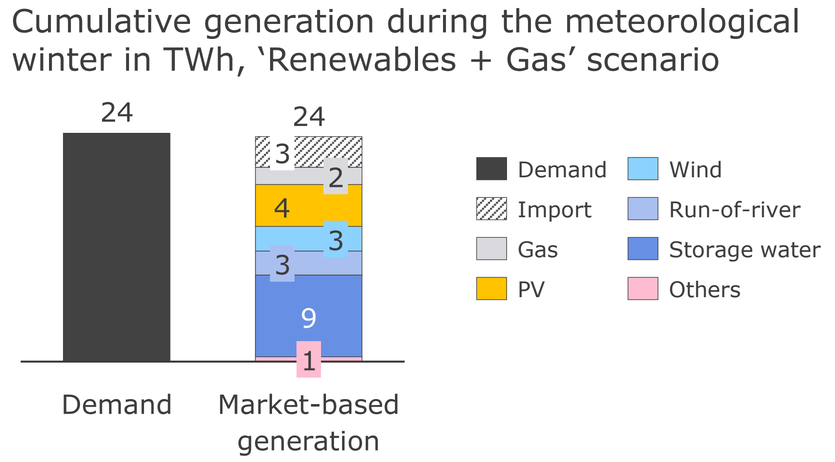
How did we model hydropower operations? *The results that are shown here are for flexible hydropower deployment in the 'Renewables' scenario, with two sensitivities: full replacement options and complete border closures. These are calculated using a fundamental market simulation by FEN (Energy Networks Research Centre, Zurich), for the year 2050.*

Deep Dive: During the meteorological winter, non-flexible generation is low. Hydropower cannot always meet demand and must be supplemented by gas or imports

Based on analyses with
FEN of ETH Zürich

Demand and non-flexible electricity generation in the meteorological winter, 2049/2050

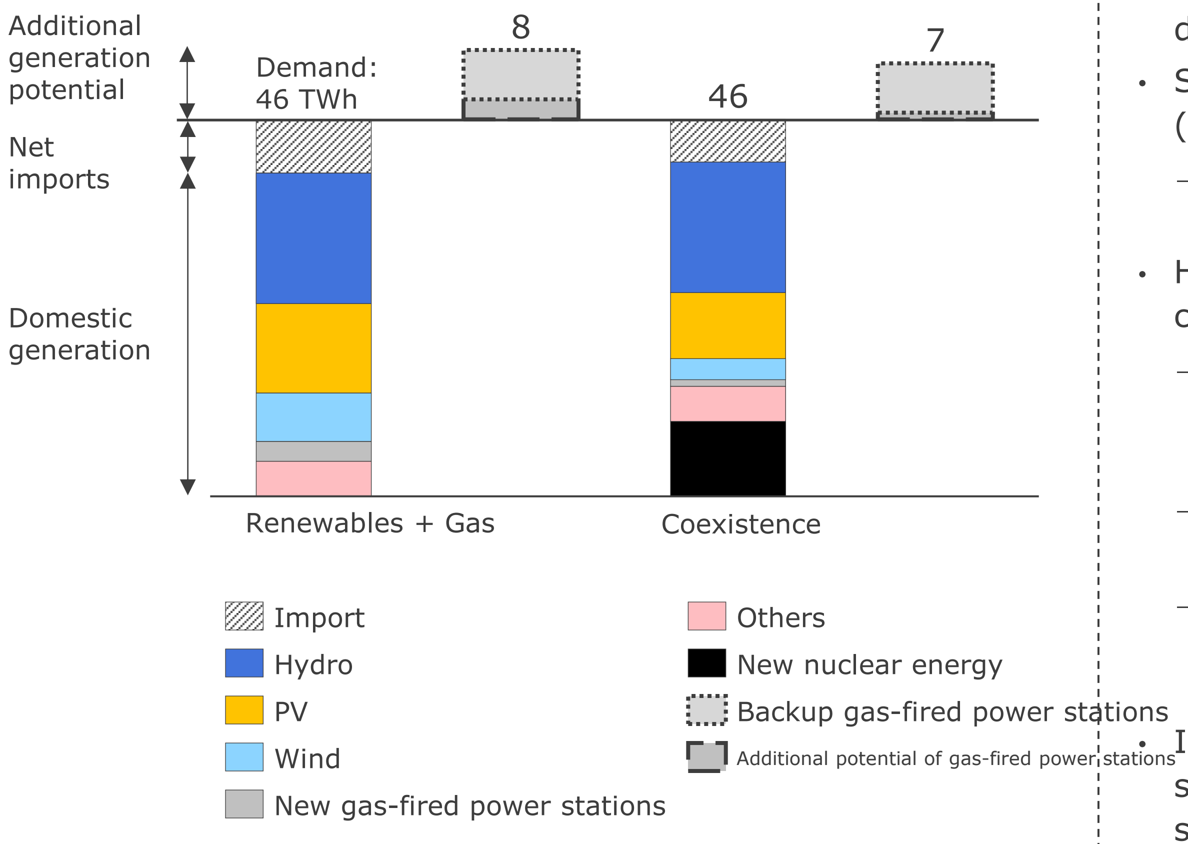




- In the 'Renewables + Gas' scenario, generation from non-flexible power plants (e.g., wind, PV, run-of-river) can contribute 10 TWh towards meeting the 24 TWh demand during the three months of the meteorological winter (December, January and February). These estimates cover an average weather year.
- PV plants only produce around 7–9% of their annual generation during the three meteorological winter months.
- Storage hydropower plants generate approx. 6–8 TWh from December to February. The exact figure depends on the distribution across the months and is influenced by the weather year. For example, by demand and generation domestically and abroad, as well as inflows. Depending on weather conditions, Hydro has the flexibility to shift production back and forth within the winter half-year.
- The major share of hydropower generation therefore falls within the three critical winter months. In the transitional months of October, November and March, non-flexible generation both domestically and abroad can make a more significant contribution to meeting demand.

There is sufficient domestic electricity generation to meet demand. Nevertheless, electricity exchange remains central to security of supply in all scenarios

Electricity generation, imports and remaining generation potential in the winter half-year of 2050 in TWh



Key findings

- In both synthesis scenarios (‘Renewables + Gas’, ‘Coexistence’), sufficient domestic electricity generation is generally available.
- Switzerland can largely supply its own needs. Imports could theoretically (without the use of reserve power plants) be limited to approx. 5 TWh.
  - A prerequisite for this is that all domestic power plants, especially nuclear and gas-fired power plants, are in operation.
- Higher imports occur purely for economic reasons, when electricity is cheaper abroad:
  - In this case, domestic power plants (primarily gas-fired power plants) operate less, leading to higher import volumes. These additional imports are not strictly necessary, but they make economic sense.
  - There are annual imports of approx. 6–7 TWh in the ‘Renewables + Gas’ scenario, as gas-fired power plants are not always used, even in winter
  - In the ‘Coexistence’ scenario, there are annual imports of ~5 TWh. Although there are fewer gas-fired power plants, nuclear power stations are expected to run continuously through winter.
- If import capacity is limited, gas-fired power plants can be ramped up at short notice. For worst-case scenarios (e.g., adverse weather, outages or shortages), additional safeguards are required. These could be implemented, for example, through reserve power plants.

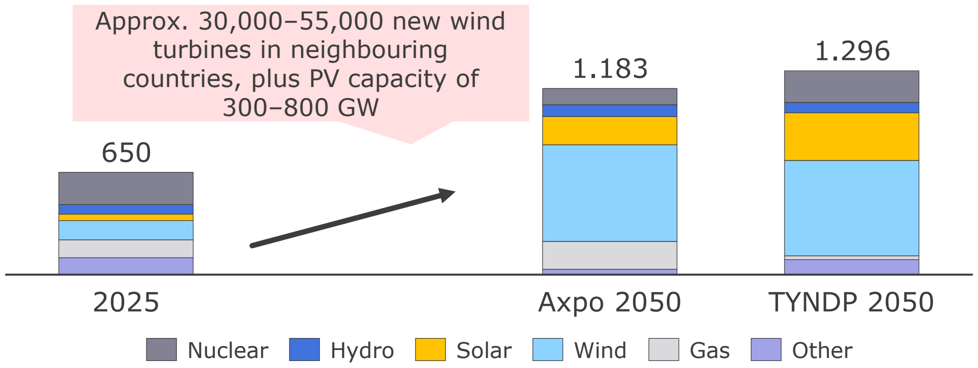
Deep Dive: Integration into the European grid enables efficient imports and exports, but production surpluses in neighbouring countries are uncertain

Based on analyses with
FEN of ETH Zürich

Production surpluses in neighbouring countries enable Swiss imports in winter, but these surpluses are uncertain

- In all calculated scenarios, there is sufficient capacity for around 5 TWh of imports. Flexible Swiss hydro allows for imports, when surpluses are available from neighbouring countries.
- It is highly uncertain whether the future will unfold as is modelled in these scenarios. The different pathways often also reflect political ambitions.
- Relying on even more imports would mean becoming increasingly dependent on the political will of neighbouring countries.
- A massive expansion must also take place in neighbouring countries.
- Grid bottlenecks, for example in Germany, could further restrict imports. Grid expansion is a lengthy process and with limited acceptance.

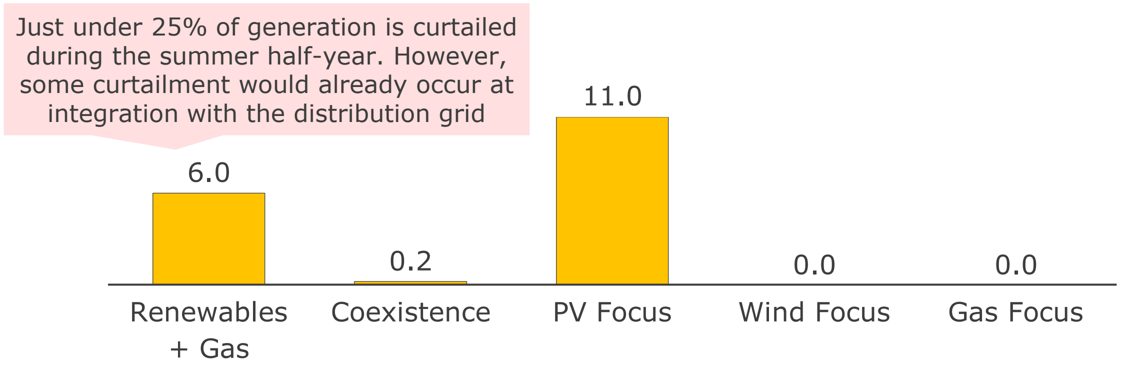
[1] 's electricity generation in neighbouring countries during the winter months, in TWh



Swiss summer surpluses can largely be absorbed by neighbouring countries

- In our simulations, summer surpluses can largely be exported, but this depends on developments abroad.
- The prerequisites for export are that flexibility must be available abroad (e.g., electricity demand for hydrogen production in Germany), and there must be sufficient grid capacity and further load flexibility.
- Without export options, significant amounts of electricity would have to be curtailed in summer, especially in a scenario with high PV expansion.
- When prices at the time of export are low, the value of surplus electricity is low.

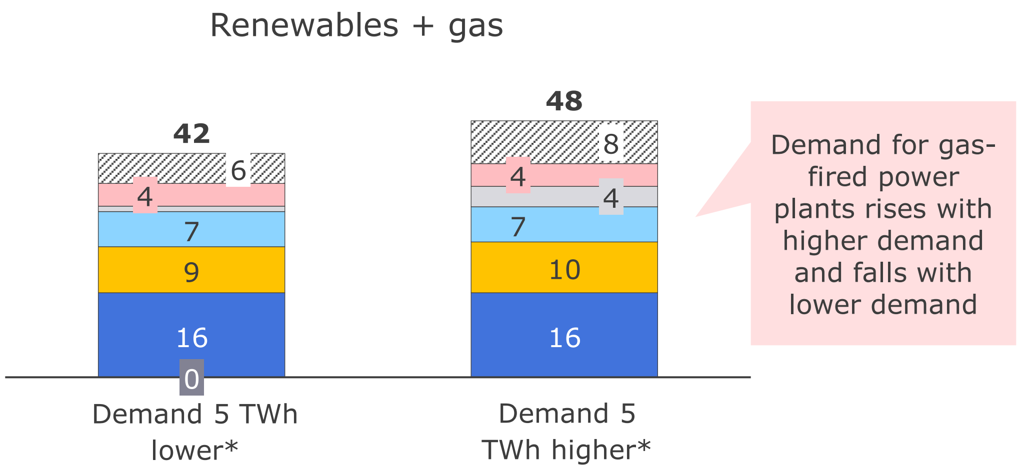
Summer curtailment if exports were not possible, in TWh



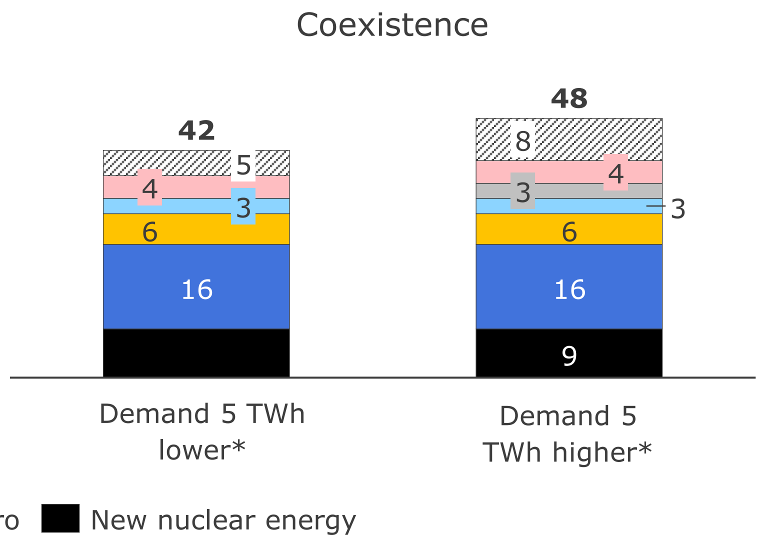
1) First scenario: Axpo assumptions regarding capacity development in other European countries – assuming 80% decarbonisation by 2050; Second scenario: ENTSO-E/ENTSOG TYNDP 'Global Ambition' scenario

Deep Dive: Scenarios are generally robust when faced with lower or higher demand, as the expansion of gas, and to some extent wind and solar PV, can be increased or reduced in the short term

Electricity generation in the winter half-year 2050, TWh



Electricity generation in the winter half-year 2050, TWh

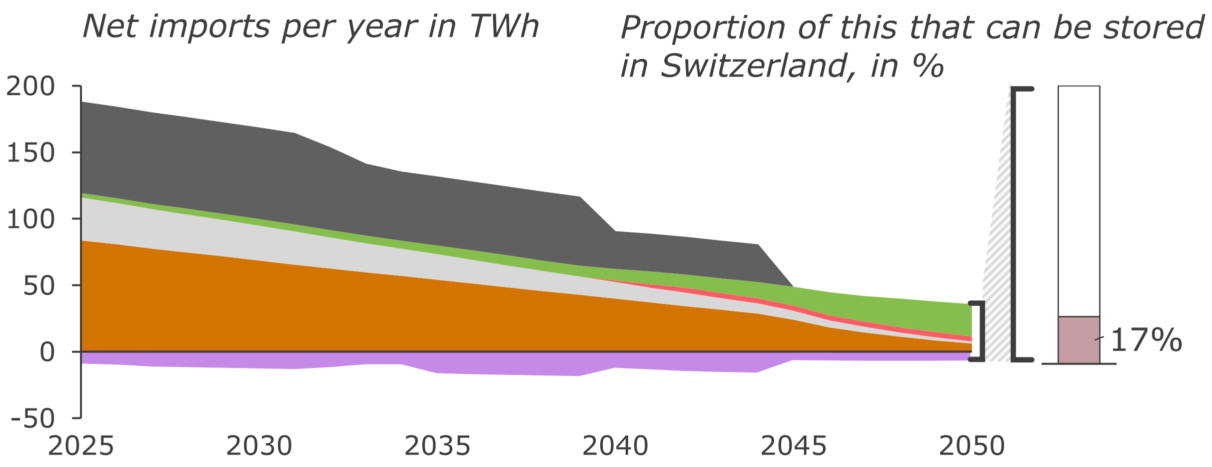


- Demand may turn out to be higher or lower than assumed. This could be as a long-term trend (e.g., stronger/weaker decarbonisation) and/or in the short term (e.g., significantly more data centres are built within a few years). Sensitivity analysis shows the impacts of +/- 5 TWh in total demand in 2050, which corresponds to approx. +/- 2.8 TWh of winter demand.
- ‘Renewables + Gas’: reduced expansion is possible for all technologies in the short to medium term. A higher expansion is primarily driven by gas, while a faster expansion of wind is unlikely and increased PV could mean even more integration challenges.
- ‘Coexistence’: changes in expansion is possible, especially for gas, PV and wind. Nuclear energy remains fairly constant regardless of whether there is lower or higher demand. This is partly due to the largeness of reactor units and long planning phase. Additional nuclear power plants are possible if demand is significantly higher.

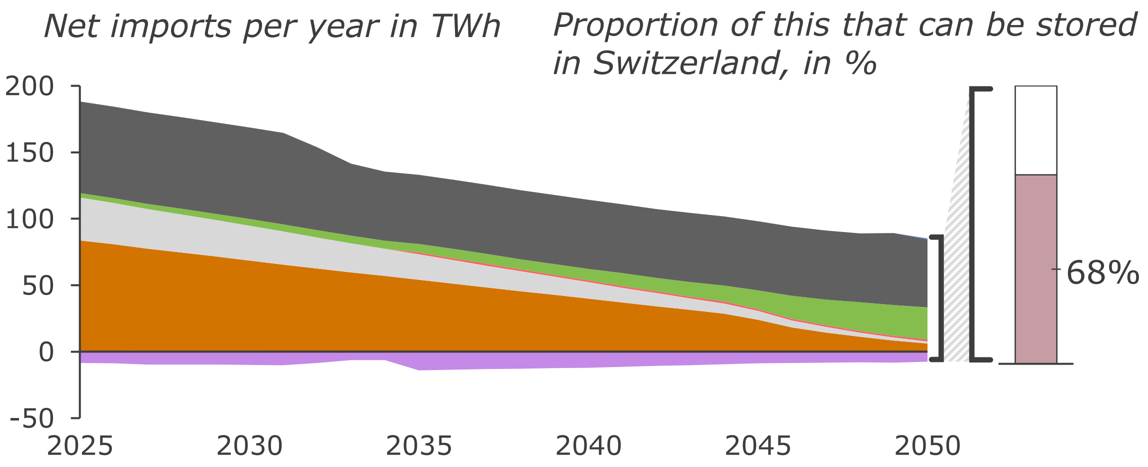
1) Lower or higher than in the original scenario, in line with the slide on the increase in demand; 2) 2.8 TWh of winter electricity can theoretically be produced by 700 MW of gas-fired power stations; the original capacity of 1.2 GW is therefore reduced to 500 MW or increased to 1.7 GW; Alternatively, more or fewer wind or PV plants could be built, but the expansion of these plants in the scenario is already ambitious

Net energy imports fall significantly in both scenarios. The lack of gas storage facilities poses a challenge for gas-fired power plants

Renewables + Gas



Coexistence (renewables + gas + nuclear)



Petroleum products | Natural gas | Natural gas (new gas-fired power stations) | Renewable gases[1] | Nuclear fuels | Electricity

Methodology assumptions:

- *Figures for net import requirements for energy carriers that are not used for electricity generation (coal, petroleum products, natural gas, renewable and synthetic gases) are from the Energy Perspectives 2050 Zero Basis. In the Base scenario, biogas is also used for electricity generation. The corresponding share has been deducted from the values for renewable gases accordingly[2].*
- *For nuclear fuels, natural gas for new gas-fired power plants and electricity, figures are taken from the respective Axpo synthesis scenario.*

- Net imports fall significantly in both scenarios. The drop is more significant in the 'Renewables + Gas' scenario, as no nuclear fuel needs to be imported following decommissioning.
- Nuclear fuel can be stored locally in Switzerland.
- For natural gas, there are no large-scale gas storage facilities or LNG terminals in Switzerland:
  - Dual-fuel solutions would increase security of supply. For this reason, additional liquid fuels are stockpiled in existing storage facilities. As oil demand falls, these capacities are increasingly becoming available.
  - Foreign gas storage facilities offer an alternative. 7.5% of Switzerland's natural gas consumption is stored in France.

1) Includes 'Renewable Energies' and 'PtX'; 2) 1.3 TWh of biogas electricity generation is included in the Zero Basis scenario in the Energy Outlook 2050, which is not accounted for in our scenarios. We assume that the energy sources must be imported. Assumption: efficiency of electricity generation from biogas 50%. Reduces the import requirement for 'Renewable Gases' by 2.6 TWh.

Both scenarios generate a similarly high level of gross domestic value added and employment. In the 'Coexistence' scenario, long-term operation is needed to maintain expertise

Based on analyses using Swiss Economics

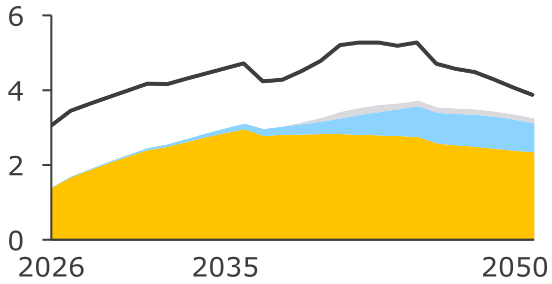
Gross value added and employment effects of the scenarios

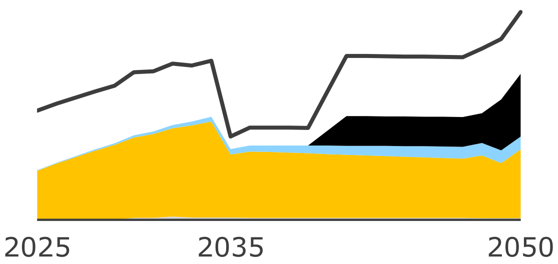
Gas Wind Solar Nuclear

Renewables + Gas

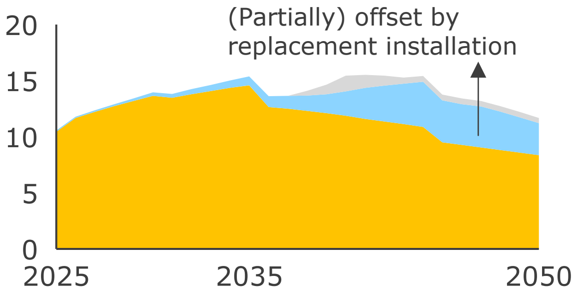
Coexistence
(renewables + gas + nuclear)

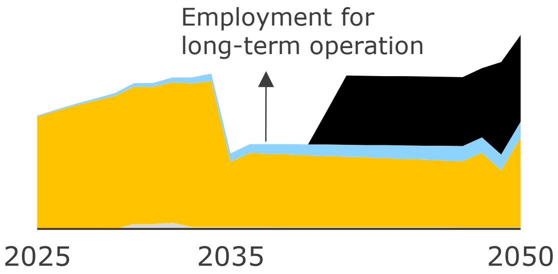
Domestic gross value added, in CHF billion / year





Domestic employment, in thousands of full-time equivalents / year





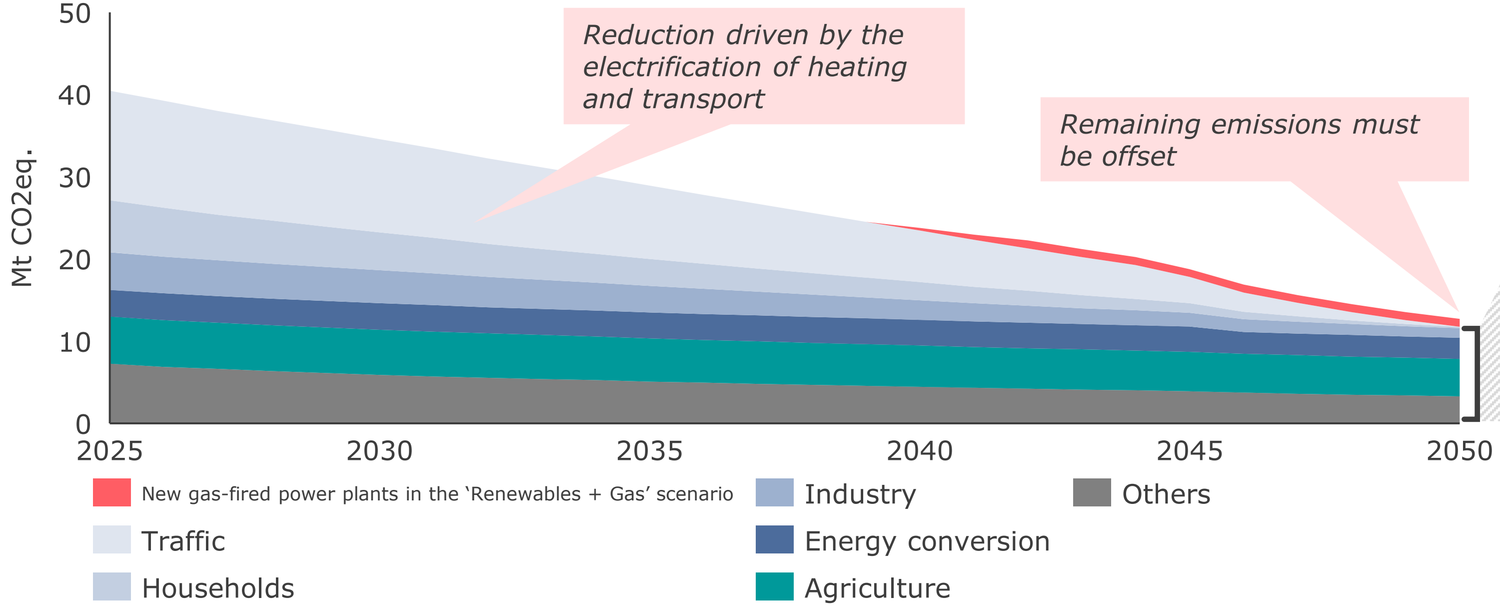
Key findings

- Both scenarios show a similarly high share of domestic gross value added: 64% for 'Renewables + Gas' and 63% for 'Coexistence':
  - In the 'Renewables + Gas' scenario, the slowing pace of expansion from 2035 onwards leads to a decline in gross domestic value added. The replacement of existing plants, which is not considered here, is likely to mitigate this decline.
  - In the 'Coexistence' scenario, the slowing rate of expansion leads to a sharp fall in domestic gross value added. Expenditure on the long-term operation of existing nuclear power plants is likely to offset this decline to some extent.
- Employment also remains at a similarly high level in both scenarios, at around 15,000 full-time positions per year:
  - In the 'Renewables + Gas' scenario, employment changes gradually. In the 'Coexistence' scenario, however, there is a risk of a 'boom-and-bust' cycle. This should be avoided through sensible regulatory adjustments.
  - The construction of new nuclear power plants leads to a sharp rise in employment and requires appropriate management. Long-term operation is key to securing technical and operational expertise for the future.

Gas-fired power plants increase greenhouse gas emissions, but can improve security of supply and thus contribute to electrification and decarbonisation

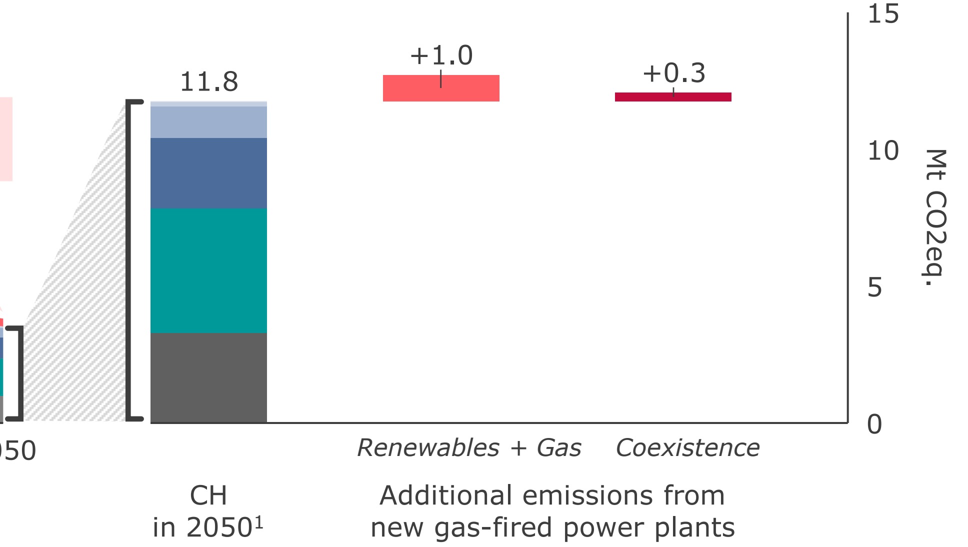
Switzerland's greenhouse gas emissions by 2050, including new gas-fired power plants

Trends according to Energy Perspectives 2050+[1] and the 'Renewables + Gas' scenario



Emissions in 2050

Switzerland according to Energy Outlook 2050+[1]



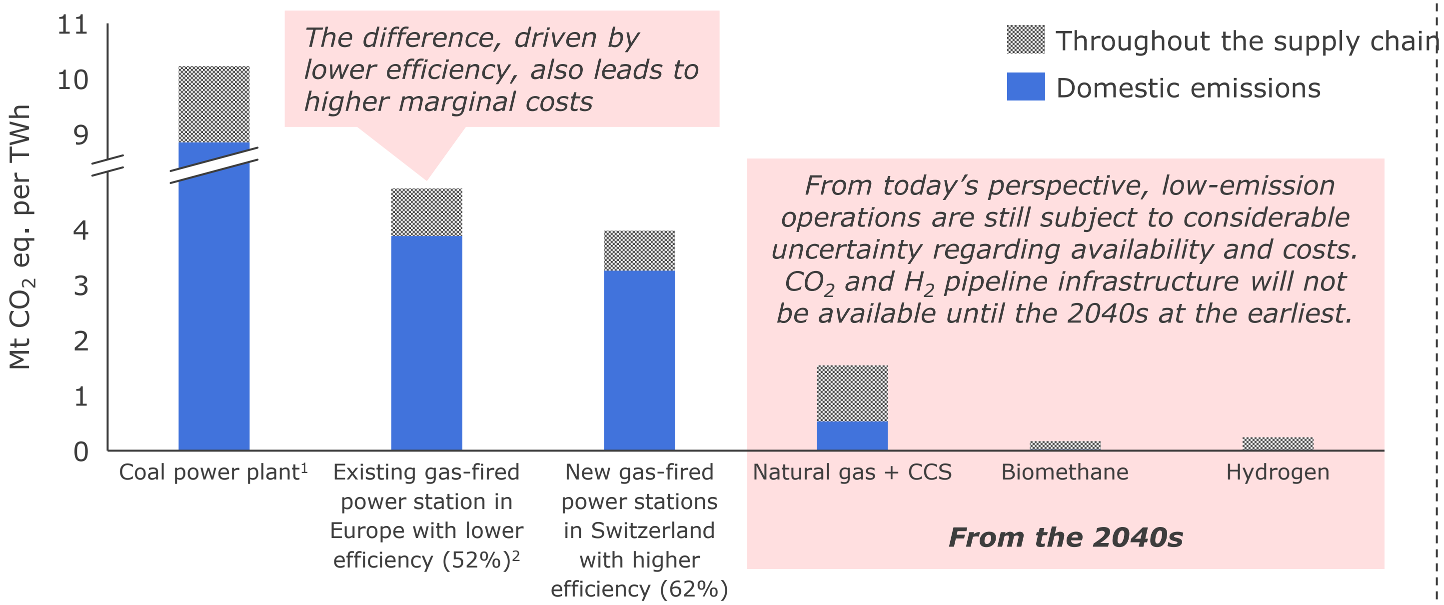
Electrification of heating and transport drives the decline in total emissions

According to the Energy Outlook 2050+, Switzerland's greenhouse gas emissions will fall significantly by 2050. To achieve the net-zero target, any emissions that remain in 2050 must be offset by negative-emission technologies, both domestically and abroad. The main driver of falling emissions is the electrification of sectors that currently have high emissions. Although using electricity from gas-fired power plants does result in additional emissions during electricity generation, these emissions are lower than the emissions from the fossil fuels that electrification directly replaces. This effect is particularly pronounced with heat pumps and electric mobility, as their high efficiency further reduces specific energy demand. As a result, total emissions across the system fall, even though additional emissions are generated in the electricity sector. If electrification is powered by even lower-emission electricity, for example from wind or solar, the reduction achieved increases. In both scenarios, the impact of gas-fired power plants on Switzerland's total greenhouse gas emissions is limited.

1) Development according to the ZERO scenario from the Energy Outlook 2050+, SFOE, in million tonnes of CO2-eq. The breakdown of total emissions by sector has been adjusted for the sake of simplicity. The contribution of new gas-fired power stations to Swiss emissions may be slightly overestimated, as emissions from fossil fuel power stations (~1 TWh in 2050) are likely already accounted for in the 'energy conversion' category in the SFOE scenarios.

New gas-fired power plants in Switzerland are more efficient than existing ones. Solutions for low-emission operation are possible by 2050, but the availability thereof and associated costs are highly uncertain

Greenhouse gas emissions from various technologies



Methodology assumptions: Comparison of emissions from different technologies

Emissions are compared based on life-cycle analyses, including domestic emissions and emissions along the supply chain, of various electricity generation technologies. An electrical efficiency of 62% is assumed for new gas-fired power plants. For comparative purposes, an existing plant with an efficiency of around 52% is shown[2]. Lower efficiency results in correspondingly higher emissions per TWh. Looking ahead, further reductions in emissions are possible from 2050 onwards, through carbon capture and storage (CCS) and alternative fuels such as biomethane or hydrogen. However, the availability and costs of these options are highly uncertain.

Key findings

- Older gas-fired power plants have higher greenhouse gas emissions (and higher marginal costs[3]) due to their lower efficiency, compared to newer, more efficient gas-fired power stations.
- Due to their lower marginal costs, new Swiss gas-fired power plants would primarily displace old, inefficient fossil fuel plants in the European electricity market. This means that total emissions would not increase and could even fall.
- Renewable energies such as wind and solar, as well as nuclear power plants, remain unaffected by this displacement effect. This is because their low marginal costs mean they are prioritised over gas-fired power plants anyway.
- By 2050, solutions for low-emission operation could be possible, but are associated with significant uncertainties:
  - Gas-fired power plants can be upgraded with CCS, which reduces total emissions by around 60%.
  - Biomethane, from Switzerland or abroad, and hydrogen produced by electrolysis using renewable electricity can be used as low-emission fuels.

1) Life Cycle Assessment of Electricity Generation Options, UNECE 2021; 2) Illustrative comparison, efficiency of Axpo gas-fired power stations in Italy: Calenia, 51.7%, Rizziconi, 51.1%. Efficiency levels of large (GW-scale) gas-fired power stations in Germany: Irsching power station 38–60%, Lausward power station 54%, Emsland natural gas power station 46–59%, Knapsack power station up to 60%; 3) Due to lower efficiency, more gas is required per MWh of electricity, which increases costs and alters the position within the merit order;

Details of the scenarios can be explored in Axpo Power Switcher

POWER SWITCHER

Scenarios in the Axpo Power Switcher

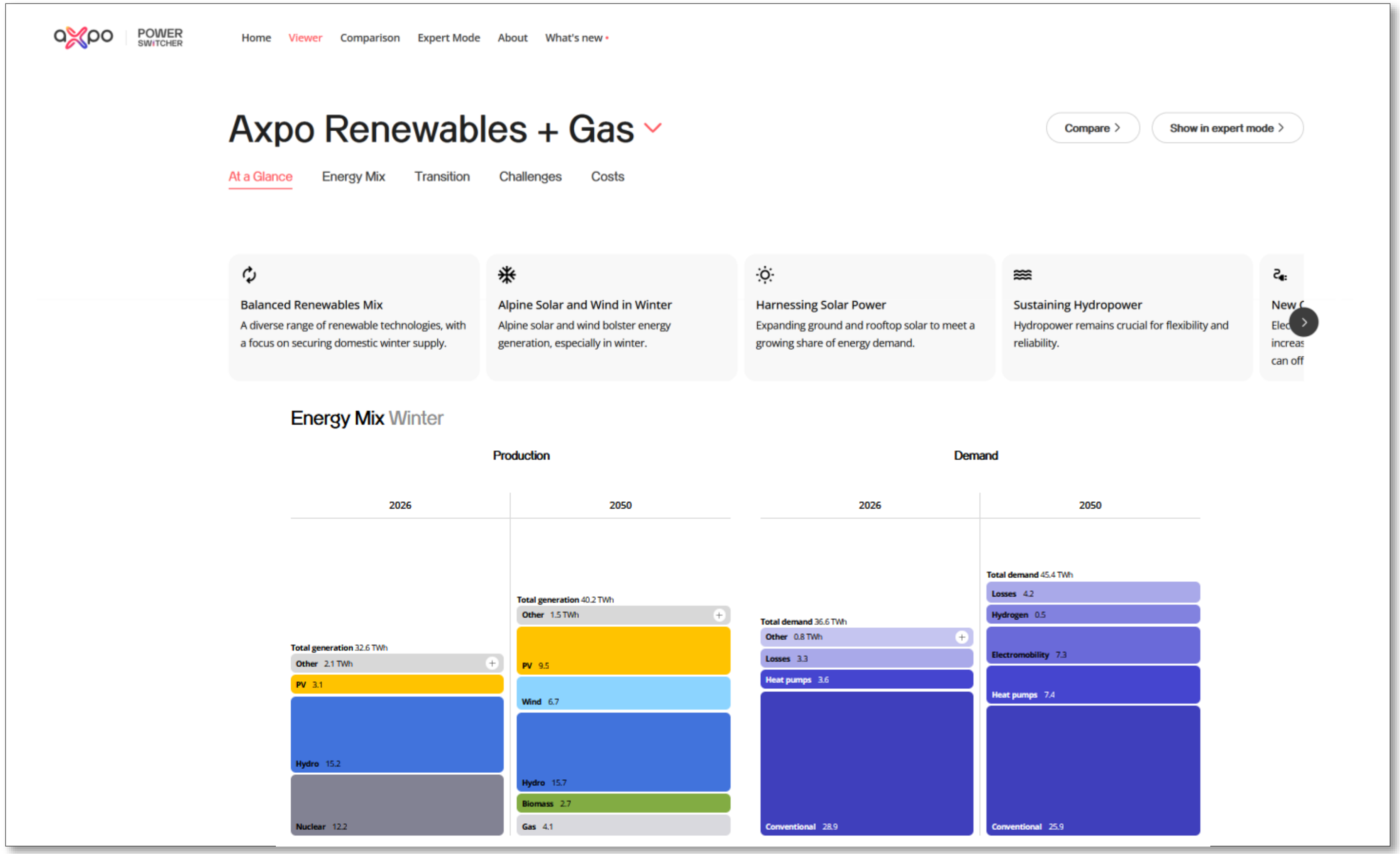
- Power Switcher displays the 'Renewables + Gas' and 'Coexistence' scenarios
- Using the Power Switcher, the electricity mix can be explored, compared and costs can be analysed

Differences between the Axpo Energy Reports and the Power Switcher

In the Energy Reports, we aim for the greatest possible accuracy. The Power Switcher, on the other hand, is designed to be fast and interactive. This means that we have had to make some simplifications there, for example:

- Gas-fired power plant operation: electricity generation from gas-fired power plants differs, as we were able to calculate detailed models in the Energy Reports. In the Power Switcher, however, we cannot calculate market coupling due to computational capacity constraints, so gas-fired power plants operate before imports.
- Electricity prices: in the Power Switcher, prices are set by the user, so revenues from plants may differ.
- System costs: evaluations may differ. For example, the system costs in the Power Switcher refer to the entire system including existing capacity, whereas in the Energy Reports the costs of expanding wind, PV, nuclear and gas capacity are evaluated.

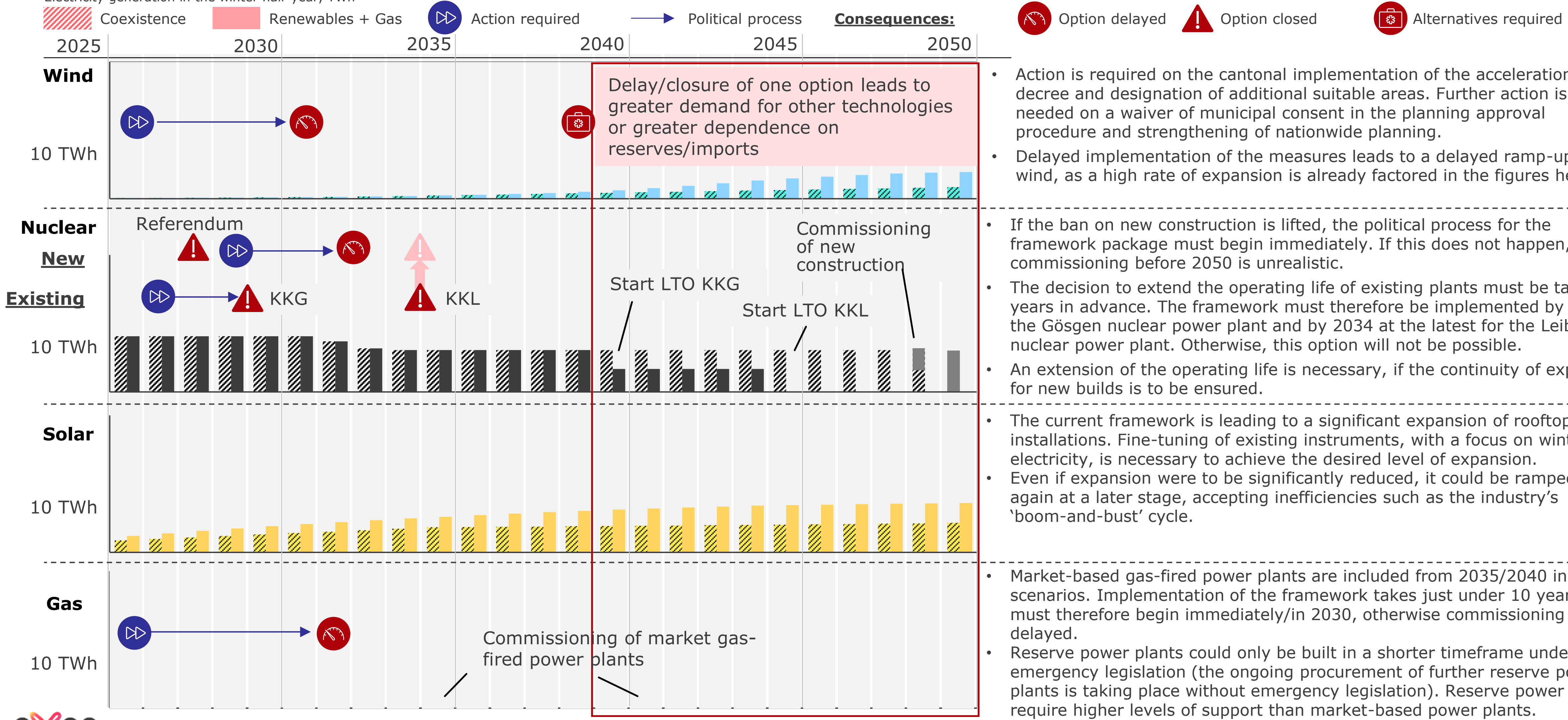
www.powerswitcher.axpo.com



04 Recommendation for action

In both scenarios, prompt action is required to achieve the necessary expansion. Higher imports and ad-hoc reserve power plants are the last resort if no action is taken

Electricity generation in the winter half-year, TWh



Wind

- Action is required on the cantonal implementation of the acceleration decree and designation of additional suitable areas. Further action is needed on a waiver of municipal consent in the planning approval procedure and strengthening of nationwide planning.
- Delayed implementation of the measures leads to a delayed ramp-up of wind, as a high rate of expansion is already factored in the figures here.

Nuclear

- If the ban on new construction is lifted, the political process for the framework package must begin immediately. If this does not happen, commissioning before 2050 is unrealistic.
- The decision to extend the operating life of existing plants must be taken ten years in advance. The framework must therefore be implemented by 2029 for the Gösgen nuclear power plant and by 2034 at the latest for the Leibstadt nuclear power plant. Otherwise, this option will not be possible.
- An extension of the operating life is necessary, if the continuity of expertise for new builds is to be ensured.

Solar

- The current framework is leading to a significant expansion of rooftop PV installations. Fine-tuning of existing instruments, with a focus on winter electricity, is necessary to achieve the desired level of expansion.
- Even if expansion were to be significantly reduced, it could be ramped up again at a later stage, accepting inefficiencies such as the industry’s ‘boom-and-bust’ cycle.

Gas

- Market-based gas-fired power plants are included from 2035/2040 in the scenarios. Implementation of the framework takes just under 10 years and must therefore begin immediately/in 2030, otherwise commissioning will be delayed.
- Reserve power plants could only be built in a shorter timeframe under emergency legislation (the ongoing procurement of further reserve power plants is taking place without emergency legislation). Reserve power plants require higher levels of support than market-based power plants.

Wind: Accelerated expansion of wind power is recommended, as it is particularly cost-effective for winter electricity supply. In particular, the implementation of the acceleration decree is necessary

Scenario-independent

ROLE OF TECHNOLOGY AND KEY FINDINGS

- **Wind power is valuable for Switzerland's electricity supply**: wind turbines generate two-thirds of their electricity during the winter months, they are low-emission, and the infrastructure requirements are comparatively low. Around 1,100 wind turbines would be needed to generate 10 TWh.
- **There is significant untapped potential:** even with moderate wind speeds, there are still many sites in Switzerland with suitable conditions. From a theoretical perspective, up to 30 TWh could be generated per year.
- **The acceleration decree and designated suitability areas shorten the approval process:** planning approval procedures, combined with the cantons' obligation to designate suitable areas, enable a shorter approval phase. These measures bring the process down from around 15 years to around 5 years (depending on cantonal arrangements).
- **Local acceptance remains the key challenge**: many of the ongoing projects are either slowed down or prevented by local referendums and objections from private individuals and associations. Or, they have to be scaled down.

SPECIFIC RECOMMENDATIONS FOR ACTION

- **Acceleration decree:** The acceleration decree must be consistently implemented at the cantonal level. In doing so, cantons should involve the municipalities but refrain from seeking formal consent as part of the planning approval process.
- **Suitable areas:** Suitable areas with a theoretical potential of around 7 TWh per year have already been identified. However, actual yield and implementation in these areas remain unclear. Cantons must identify further suitable areas.
- **Strengthening planning from a national perspective:** Strengthening the binding nature of federal guidelines (the so called 'Wind Concept'), nationwide monitoring of the implementation thereof (suitable areas, project development, permits), and coordination between the federal government, cantons, project developers and other stakeholders regarding suitable areas and specific projects.
- **Further measures:** Should the expansion targets set by the federal government not be achieved, even with strengthened nationwide planning and coordination, further measures would need to be considered. One example could be the creation of a national sectoral plan for wind energy.

Kern: Existing nuclear power plants need a framework to ensure a longer operating life. For new power plants, the state would have to assume risks

	THE ROLE OF TECHNOLOGY AND KEY FINDINGS	SPECIFIC RECOMMENDATIONS FOR ACTION
Regardless of scenario	• **Extended operation of existing nuclear power plants is the most cost-effective option to secure large volumes of winter energy** and would buy Switzerland time, should the roll-out of other technologies be delayed. • A decision on extending the operating life must be made ten years before decommissioning begins.[1]	• **Timely implementation of appropriate regulatory measures** to reduce the political, regulatory and financial risks that existing plants face. For example, transferring existing plants to a 'Regulated Asset Base' (RAB) could be a viable approach.[2]
Coexistence	• **New nuclear power plants would diversify the electricity mix, just as they do today**. New power plants open an additional option. This is particularly important if the expansion of other plants, such as wind or gas, continues to prove difficult. • **Existing nuclear power plants should remain in operation until the new plants come online**, so that the continuity of expertise is ensured and sufficient winter electricity is available. • **Comprehensive assumption of political, regulatory and financial risks by the state is necessary**. Without this assumption of risk (including financial support), the financial risks of new nuclear power plants are not bearable for companies.	• **Lift the ban on new nuclear power plants** • **Press ahead with project development, without delay:** Project development should commence following the referendum, to build up the necessary maturity for decision-making[3]. If this does not happen, commissioning by 2050 is unlikely. Costs of around CHF 100 million would have to be borne by the state, regardless of whether a new plant is ultimately built. • **Establish a legal and regulatory framework for the construction and operation of new nuclear power plants:** Adaptation of licensing procedures, introduction of support instruments and state participation (public-private partnerships) to assume the political, regulatory and financial risks. With such a framework, companies essentially act as operators. • Assess **construction based on 'state of the art retrofitting technology'.**

1) For KKG this would be until 2029, for KKL until 2034. Ten years are required for the preparations and process of obtaining the decommissioning order, as well as for decommissioning work; 2) In a RAB model, the federal government or the regulatory authority sets the permissible revenues. These correspond to the recognised costs plus an agreed rate of return on capital. The mechanism is similar to the current regulation of electricity grids; 3) Developing the technical and economic readiness for decision-making involves working with manufacturers to assess the feasibility of various internationally proven reactor designs – such as the AP1000 or EPR – and comparing their strengths and weaknesses in terms of economic viability and implementation feasibility. A key step is verifying whether these designs meet Swiss safety and regulatory requirements.

Solar: Rooftop PV has already been approved and installed but grid integration and redistribution effects must be addressed promptly. Ground-mounted PV can be deployed as a cost-effective alternative.

	ROLE OF TECHNOLOGY AND KEY FINDINGS	SPECIFIC RECOMMENDATIONS FOR ACTION
Regardless of the scenario	• **PV is becoming a cornerstone of Switzerland's electricity supply.** Rooftop PV is currently the only technology undergoing significant expansion in Switzerland. • **The impact of rooftop PV on distribution grid expansion needs should be addressed.** This requires integration measures such as targeted feed-in limits and the implementation of controllable demand (e.g., charging of electric vehicles). Home storage systems also help from a technical perspective, but they are not cost-effective from a system-wide view. • **Roof-mounted PV with self-consumption currently leads to redistribution effects**, as end customers with rooftop PV reduce their share of grid costs and the grid surcharge. The resulting shortfall must be borne by the remaining end customers through higher grid charges.	• Fine-tune **PV subsidies** to achieve the desired expansion. • **Implement integration measures prior to grid expansion:** In the event of continued PV expansion, integration measures such as feed-in limits of 50% or more, depending on the situation, should be examined. This would avoid cost-inefficient grid expansion. • **Total PV support – both direct and implicit – should** be **reported transparently** and calculated when calculating support efficiency. This enables comparability with other technologies and between plant types. • A 'polluter-pays' approach to the distribution of grid costs (and the introduction of incentives for grid-friendly behaviour) would require an **adjustment to the existing grid tariff design**. For example, so-called power tariffs could be used more widely, which would also provide incentives to reduce consumption peaks.
Renewables + Gas	• **Ground-mounted installations** are **a more cost-effective alternative,** but present conflicts when it comes to land use, including with agriculture. Alpine PV is comparatively expensive due to complex construction.	• **Suitable areas for ground-mounted installations** should be designated, and sites for already developed areas should be included in the land-use plan. • Implement **the acceleration decree** to shorten the processing time for ground-mounted PV in suitable areas.

Gas: Market-active gas-fired power plants, which do emit CO_2, should be permitted, to help secure Switzerland's electricity supply. The need for new capacity depends on the situation.

Scenario-independent

ROLE OF TECHNOLOGY AND KEY FINDINGS

- **Gas-fired power plants operating on the market help to secure Switzerland's electricity supply.** They supply electricity particularly when power from renewables is in short supply both domestically and abroad. However, these are effectively excluded under current regulations.
- **The required number of gas-fired power plants depends** on the operating life of existing nuclear power plants, the expansion rate for other technologies, and how electricity demand evolves. For example, the later the expansion of other technologies takes place, the higher the gas-fired power plant capacity that will be required.
- **Without gas-fired power plants, the only options left are ad-hoc reserve power plants and an increase in imports** in the event of unforeseen developments. Reserve power plants require significantly higher subsidies, as they cannot generate market revenue.
- **Gas-fired power plants cause emissions**, as they are expected to be fuelled by natural gas, at least in the medium term. From today's perspective, low-emission operation is associated with many uncertainties regarding both the availability and costs of such operations.

SPECIFIC RECOMMENDATIONS FOR ACTION

- **Prompt action is needed** to operate gas-fired power plants by 2035. Establish a legal/regulatory framework now and decide in early 2030 whether gas-fired power plants should be put out to tender.
- **A support mechanism should be established**, which is also open to gas-fired power plants. This could be, for example, through a tender for additional winter capacity.
- **The double burden imposed by the CO_2 tax should be removed**. Swiss gas-fired power plants can only compete fairly at an international level if the tax burden is comparable. In the event of participation in the ETS, the CO_2 tax should be fully refunded.
- **Cantonal regulations on waste heat utilisation must be amended**. Currently, even modern, highly efficient gas-fired power plants cannot reasonably comply with these. In principle, the downstream steam cycle should be considered sufficient heat utilisation.
- **Fuel must be available in critical situations**. This requires either domestic gas storage facilities, guaranteed access to foreign gas storage facilities even in times of crisis, or plants with dual-fuel solutions as well as access to storage facilities for liquid fuels.

Consistently focus funding schemes on winter electricity

Status quo

- Technology- and plant-specific funding instruments result in a patchwork of measures. Funding is distributed indiscriminately rather than allocated based on the respective contribution to winter electricity.
- Funding levels are set based on the federal government's economic viability calculations rather than those of project developers. Auctions are only planned for large-scale PV projects.
- There are funding caps for large-scale plants that are inappropriate. For example, caps that are too low for large-scale PV plants and absolute maximum contributions for biomass plants.

Fundamental need for adjustment

- Subsidies should be set in a technology-neutral way, based on the contribution to winter electricity. This should include a transparent comparison between different plant sizes and consider implicit subsidies, such as reduced grid cost contributions for self-consumption.
- Extension of the support instruments due to expire in 2035 in good time. These will continue to be needed beyond that date.

Auctions for winter electricity

- Auctions for winter electricity result in the most efficient allocation of funding. Technology neutrality broadens the pool of bids and further increases funding efficiency.
- In addition to sliding-scale market premiums, investment subsidies based on potential winter production could be auctioned off for flexible plants, such as gas-fired power plants.
- The auctions could be financed via the grid surcharge fund. An additional 'winter electricity surcharge' is also conceivable, which would reduce the necessary level of the grid surcharge accordingly.
- The surcharge at the auction could be accompanied by simplified authorisation procedures. For example, the principle of overriding national interest and faster processes. This could increase the number of projects.

Dealing with small-scale installations

- Small-scale installations can continue to be supported through flat-rate, one-off payments, staying outside of auctions.
- The level of support should be based on the contribution to winter electricity, for example, CHF per unit of winter electricity potential. It could also be based on the results of the auctions for winter electricity.
- Small-scale installations should also be guided by market price signals and have no incentive to feed electricity into the grid when prices are negative.
- Any remaining implicit support should be transparently disclosed and taken into account accordingly.

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