Nuclear Technology Development and Economics
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Achieving Net Zero Carbon Emissions in Switzerland in 2050

Low Carbon Scenarios and their System Costs

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NEA No. 7631

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Specific areas of NEA competence include the safety and regulation of nuclear activities, radioactive waste management, radiological protection, nuclear science, economic and technical analyses of the nuclear fuel cycle, nuclear law and liability, and public information. The NEA Data Bank provides nuclear data and computer program services for participating countries.

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Foreword

This report by the OECD Nuclear Energy Agency (NEA) studies different scenarios under which Switzerland can achieve its ambitious objective of net zero carbon emission in 2050. To this end, it establishes the total system costs of five low-carbon generation mixes in the Swiss electricity sector. A key feature differentiating the scenarios is the relative contribution of nuclear energy and variable renewables, in particular solar PV, to electricity supply in 2050. In all scenarios, Switzerland's large endowment of hydroelectric resources is expected to continue to make a major contribution. The analysis is further enriched by relating the scenarios to different degrees of interconnection of the electricity systems of Switzerland and its European neighbours, a key determinant of costs and revenues on both sides of the border.

During the preparation of this report, it was well understood that the current central scenario of the Swiss energy strategy aims at reaching net zero by foreseeing primarily solar PV, and a smaller share of wind, as a complement to hydroelectricity and electricity imports, assuming that currently operating Swiss nuclear plants will have been closed before 2050. Swiss law does not allow for the construction of new nuclear plants; however, it also does not limit the duration of the operation of existing nuclear plants. In several NEA member countries, the long-term operation (LTO) of nuclear power plants is currently being discussed or already implemented to reduce or limit carbon emissions and to ensure the security of electricity supply. Commitments to reach the net zero target have given additional impetus to these efforts. It is thus natural to also analyse the potential contribution of the long-term operation of the two youngest Swiss nuclear plants in a perspective of achieving net zero in 2050 in a cost-effective manner.

Comparing the system costs of a renewables-only scenario with the costs of a combined nuclear and renewables scenario is the main contribution of this report. Additional scenarios, such as building new nuclear plants or new gas plants, were provided for comparison purposes. All five scenarios had to contend with the fact that by 2050, the Swiss electricity sector will not only need to satisfy existing demand but also substantial levels of additional electricity demand. This increase stems partly from existing forms of energy services that are currently provided by fossil fuels in sectors such as residential heating or road transport and partly from emerging new usages such as hydrogen production.

Resources for this report were provided in the form of a voluntary contribution from *Swissnuclear*, the Swiss industry association of nuclear operators. Throughout its preparation, this report has benefitted from the accompaniment of a Management Group of stakeholders that provided country-specific, technical input regarding the Swiss energy and electricity systems and a Scientific Advisory Council. The latter was instrumental in helping to overcome a number of methodological challenges in modelling the unique Swiss energy systems with its high capacity levels of hydroelectric generation and interconnection with the NEA's POSY linear programming model for electricity sector analysis. This report thus combines the experience of the NEA in system cost analysis with the in-depth knowledge of the Swiss energy sector of the Management Group and the high scientific competence of the Scientific Advisory Council (SAC). The responsibility for the results remains solely with the NEA.

Acknowledgements

This report was written by Dr Jan Horst Keppler, Nuclear Energy Agency (NEA) Chief Economist, Dr Anne-Laure Mazauric, Junior Energy Analyst, and Francesco Tassi, NEA intern. The NEA's POSY electricity sector model that underlies the analysis was developed by Dr Guillaume Krivtchik while working as an energy modeller at the NEA. This work was undertaken as part of the work programme of the NEA Division for Nuclear Technology Development and Economics (NTE). Diane Cameron, Head of NTE, provided managerial oversight. Dr Michel Berthélemy, NTE Energy Analyst, contributed with additional input during the early stages of the report.

A group of Swiss stakeholders provided country-specific data and insights. Its members were Roger Lundmark, Head of Power Plant Support (Swissnuclear), Cédric Vessiller, Asset Manager (Alpiq), and, during later stages of preparation, Nils Röthlisberger (Swissnuclear) as well as Peter Schoenenberger (Axpo) and Thomas Schmid (BKW). The Swiss Federal Office of Energie (SFOE) and the Association of Swiss Electricity Companies (VSE/AES) were invited on a voluntary basis to provide further expert input. The report benefitted substantially from both the contributions of the stakeholder group as well as the voluntary insights provided by SFOE and VSE on the basis of their deep knowledge of the Swiss electricity system. The electricity system data that was made available as well as the technical issues raised during the modelling process substantially helped to improve the report.

The overall appropriateness of the modelling approach and methodology adopted in this study were periodically reviewed by the Scientific Advisory Council (SAC), which provided valuable input and feedback on the analysis. The SAC was chaired by Marko Aunedi (Imperial College London) and other members included Marco Cometto (International Atomic Energy Agency), Erik Delarue (KU Leuven), Tom Kober (Paul Scherrer Institute). Dr Evangelos Panos, Modeller (Paul Scherrer Institute), also provided data and support on the modelling part of the study. While best efforts have been made to consider the inputs from the Scientific Advisory Council, the findings of the study reflect only the views of the authors.

Last but not least, the report gained from the oversight and comments of the NEA Committee on Nuclear Development and the Fuel Cycle (NDC) under its Chair Patrick Lederman and the NEA Working Party on Nuclear Energy Economics (WPNE) under its Chair William D'haeseleer and co-chair Brent Dixon.

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List of abbreviations and acronyms

BWR	Boiling water reactor
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
DETEC	Federal Department of the Environment, Transport, Energy and Communications (Switzerland)
ElCom	Electricity Commission (Switzerland)
ENSI	Federal Nuclear Safety Inspectorate (Switzerland)
EP2035	Energy Perspectives 2035
EP2050+	Energy Perspectives 2050+
ES2050	Energy Strategy 2050
EU	European Union
GEK	Overall energy concept
GWh	Gigawatt hours
IEA	International Energy Agency
JASM	Joint Activity Scenarios Modelling
KEV	Compensatory feed-in remuneration at cost
kWh	Kilowatt-hour
LCOE	Levelised cost of electricity
LP	Linear programming
LTO	Long-term operation
MILP	Mixed-integer linear optimisation
MIT	Massachusetts Institute of Technology
MWh	Megawatt hours
MWh_{VRE}	Megawatt hour of variable renewable energy
NEA	Nuclear Energy Agency
NET	Negative emission technology
NTC	Net transfer capacity
NTE	Nuclear Technology Development and Economics (NEA)
OCGT	Open-cycle gas turbine
O&M	Operation and maintenance

PEM	Proton exchange membrane
POSY	NEA Power System Model
PSI	Paul Scherrer Institute
PV	Photovoltaic
PWR	Pressurised water reactor
SCCER	Swiss Competence Centers for Energy Research
SFOE	Swiss Federal Office of Energy
STEM	Swiss TIMES Energy Model
TSO	Transmission system operator (Switzerland)
TWh	Terawatt hours
VRE	Variable renewable energy
WNA	World Nuclear Association

Executive summary

Switzerland is aiming to achieve net zero carbon emissions by 2050. While there is consensus in the Swiss government and society to achieve this ambitious objective, the discussion about the appropriate generation mix to realise it remains open. In this situation, the present report by the Nuclear Energy Agency (NEA) studies the total system cost and electricity generation mixes of different scenarios under which Switzerland can achieve this ambitious objective. Key features differentiating the scenarios are the relative contributions of existing nuclear energy and variable renewables (VRE), in particular solar PV, to the electricity supply in 2050.

As one of the NEA member countries with the lowest carbon emissions, Switzerland is well positioned to achieve its objective of net zero carbon emissions. The main features enabling a net zero future are its large endowment of hydroelectric resources and its high degree of interconnection with its European neighbours, allowing for a high level of mutually beneficial electricity trades. However, the Swiss energy sector is not devoid of challenges.

Key questions pertain to the degree of interconnection with European electricity markets and the role of existing nuclear power plants. Although nuclear energy has contributed since 1969 to low-carbon emissions and high levels of electricity security, Switzerland voted in 2017 to no longer allow the construction of new nuclear power plants. Nevertheless, a preceding referendum in 2016 rejected proposals to limit the operating period of existing nuclear power plants. At the same time, a formal electricity agreement between Switzerland and the European Union continues to remain elusive, even if it can be expected that due to its geographic location and the flexibility provided by its hydropower reserves, Switzerland will remain integrated with European electricity markets to facilitate the respective pursuit of net zero objectives. In addition, in 2050, the Swiss electricity sector will need to satisfy higher levels of electricity demand than today. On the one hand, this is due to additional demand for energy services in industry, commerce, the residential sector and transport. On the other hand, it is due to an additional draw from the energy sector itself through increased charging of reservoirs and batteries or hydrogen production.

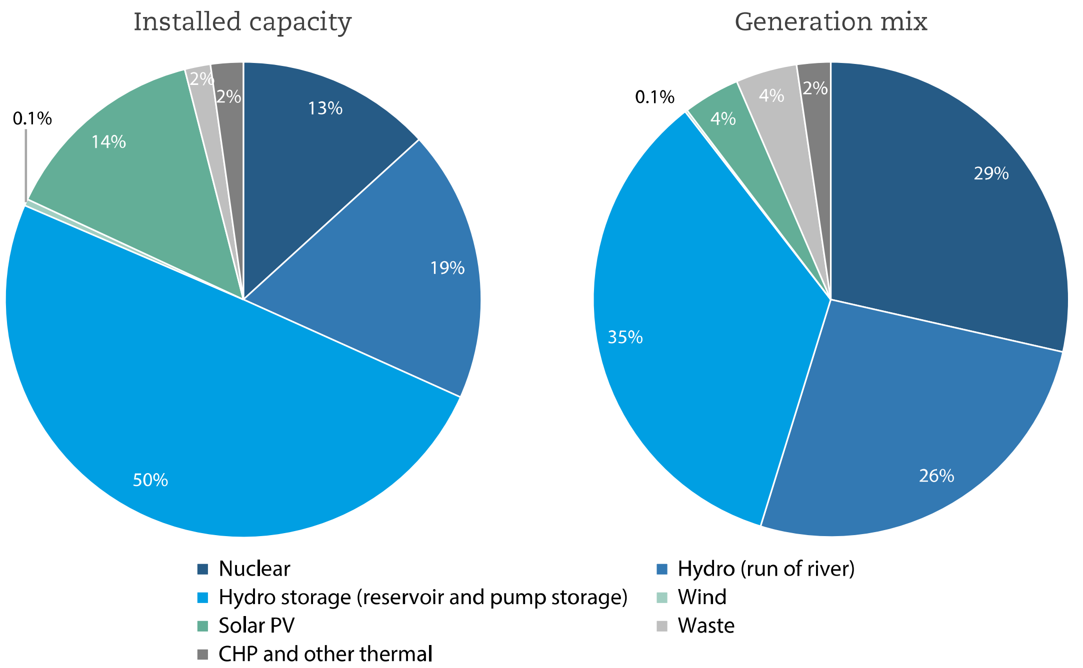
The current central scenario of the Swiss energy strategy aims at reaching net zero by relying primarily on solar PV, and a smaller share of wind, as a complement to hydroelectricity and electricity imports, assuming that the Swiss nuclear plants will have been closed before 2050. Yet as Swiss law does not limit the duration of the operations of existing nuclear plants, the question of a potential contribution in 2050 arises. Several NEA member countries are discussing or have already planned long-term operations (LTO) of nuclear power plants for 60 or even 80 years to limit carbon emissions and ensure the security of electricity supply. Commitments to reach the net zero target have given additional impetus to these efforts. The question thus arises as to what the contribution of the long-term operations of the two youngest Swiss nuclear plants could be to achieving net zero in 2050 in a cost-effective manner.

Comparing the system costs of a renewables-only scenario with the costs of a combined nuclear and renewables scenario is the principal focus of this report. Additional scenarios, such as modelling new nuclear plants or new gas plants, are provided for comparison purposes. In a context of ambitious efforts to achieve climate targets and increasing uncertainty regarding the security of electricity supply, this report aims to set out the costs and characteristics of possible net zero scenarios to provide information to the Swiss energy debate.

The Swiss electricity system

The current low carbon intensity of the Swiss electricity sector is due to high shares of hydroelectricity and nuclear energy, alongside a small share of solar PV and wind in the generation mix. Residual emissions are due to a number of small, decentralised cogeneration plants for both industrial and domestic electricity and heat consumption (see Figure ES1).

Figure ES1. **Installed capacity and generation mix in 2021 (GW and TWh)**



Note: PV = photovoltaic; CHP = combined heat and power.

Hydroelectric reservoirs and pump storage units are also important providers of flexibility. Nuclear power plants and run-of-the-river plants instead operate as baseload producers. Nuclear energy is Switzerland's second largest source of electricity, contributing 13% of its capacity and 29% of its electricity. The annual output of nuclear power plants is of the order of that of either run-of-the-river hydroelectric plants or that of reservoirs and pump storage units combined. In 2022, nuclear energy was produced by the four reactors Beznau 1 and 2, Gösgen and Leibstadt. Despite a stated assumption of 50-year operation of nuclear power plants, as considered for instance in Switzerland's Long-Term Climate Strategy (FOEN, 2021), a progressive shift towards 60 years of nuclear power plant operation can be observed in informal policy discussions, utilities' plans, and academic models. Switzerland's 2050+ *Energy Perspectives* report thus features a 50-year scenario and a 60-year scenario (Prognos et al., 2021).

The characteristics of nuclear power generation, i.e. its ability to produce large amounts of baseload power in a predictable manner, coupled with the large Swiss interconnection capacity make a sizeable contribution to reducing the economic costs of the Swiss power system. While operated in a less flexible manner than reservoirs and pump storage facilities, nuclear baseload enables Switzerland's more flexible hydro resources to contribute to profitable electricity trading next to satisfy Swiss domestic demand.

For the time being, the contribution of non-hydro renewables to total electricity generation is modest. However, many scenarios including the reference study *Energieperspektiven 2050+* commissioned by the Swiss Energy Ministry foresee significant additional amounts of variable renewable energy capacity to be installed to achieve *net zero* emissions in its energy sector. The *ZERO base* scenario of *Energieperspektiven 2050+* thus estimates that Switzerland will generate

44% of its electricity from VRE in 2050 (Prognos et al., 2021). The well-regarded JASM study prepared by a consortium of research institutes lead by the Paul Scherrer Institute (PSI) assumes in its Climate Policy (CLI) scenario, also for 2050, that VRE will contribute 34% of total generation (Panos et al., 2021).

Although not part of the European Union, Switzerland is a key platform for European electricity flows and trading. Strategically placed between Austria, France, Germany and Italy, Swiss flexible hydroelectric resources are an important element in balancing electricity demand and supply for its neighbouring countries. The role played by Swiss hydroelectricity is further increased by the fact that the electricity sectors of its four neighbouring countries differ strongly. Electricity trading, however, is not only beneficial for Switzerland's neighbours. The ability to buy electricity when it is cheap elsewhere and to sell it when it is expensive is an important element for reducing overall costs.

The evolution of electricity demand will be a crucial determinant of the feasibility and cost of Switzerland's net zero carbon objective in 2050. Switzerland is currently not a highly electrified country. In 2022, only about a quarter of its energy consumption stemmed from electricity. As a comparison, in highly electrified countries such as Norway almost half the energy is consumed in the form of electricity.

For the scenarios in this report, the exogenous demand for energy services in 2050 was based on the Swiss JASM study with its detailed representation of different end-use sectors (Panos et al., 2021), while endogenous energy sector demand for charging and hydrogen production was modelled as a function of the generation mix for each scenario. In 2021, energy services demand was driven by households (34.8%), followed by industry (29.5%), the commercial sector (26.0%), transport, including the legendary Swiss railroads, (8%) and finally agriculture and forestry (1.6%). Peak electricity demand was slightly over 10 GW with capacity for both imports and exports of electricity being of a comparable magnitude.

A growing literature to inform the Swiss policy debate

There exists an ample and growing literature on the costs of different low-carbon scenarios in the Swiss energy and electricity sectors. The present report on the system costs of scenarios with different shares of nuclear and variable renewables under a net zero carbon constraint by 2050 adds to the literature by employing the NEA's detailed POSY linear optimisation model with 8 760 hours per year and a careful representation of the economically important electricity trade flows between Switzerland and its European neighbours.

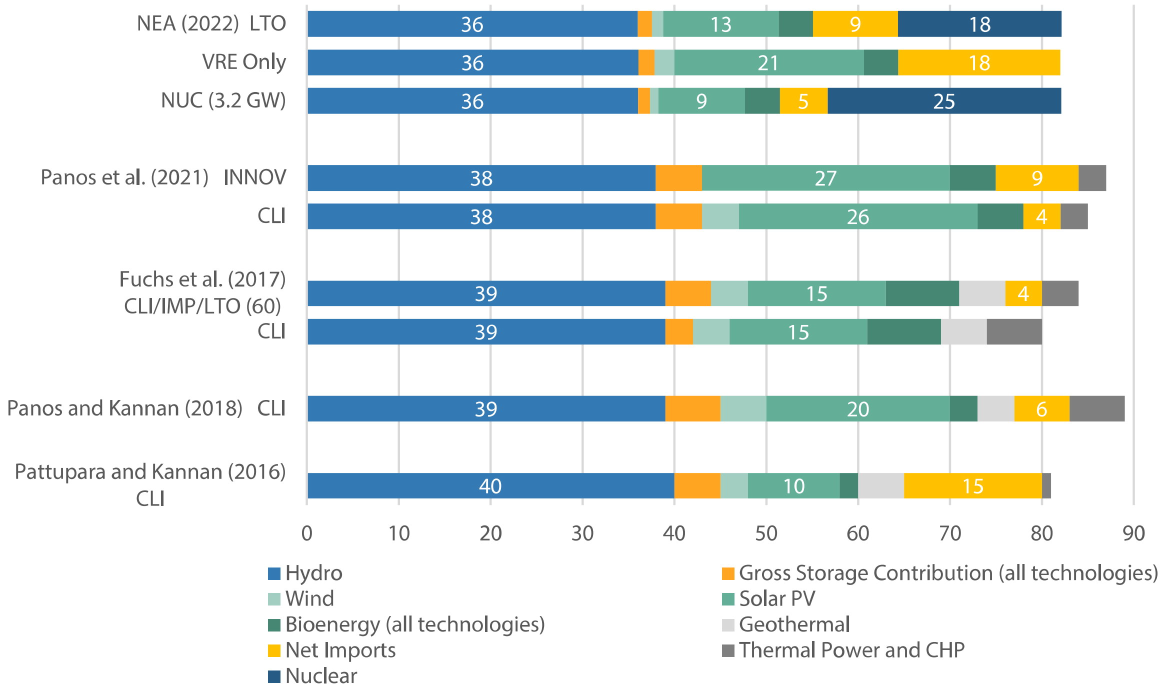
Several previous studies, including both near zero emissions as well as net zero emissions scenarios, have modelled Switzerland's future electricity generation mix and associated costs. Most studies employ the Swiss TIMES Energy Model (STEM), a technology-rich cost-optimisation model for the Swiss energy system developed by the Paul Scherrer research institute. STEM includes the detailed demand structures for more than 90 energy end uses as well as hundreds of technologies, and infrastructures for 17 energy demand subsectors (Panos et al., 2021). The EP2050+ report (Prognos et al., 2021), employs its own bottom-up energy model, but does not include cost optimisation.

The already mentioned JASM study was also produced on the basis of the STEM model in a collaborative effort of the modelling teams from eight Swiss Competence Centres for Energy Research (SCCER) to explore possible pathways towards net zero goals (Panos et al., 2021). The study included in particular a net zero scenario (CLI) that provided useful input, notably for the characterisation of the demand side, also to this report, although final energy and capacity mixes differ markedly.

Considering studies with a *net zero* carbon constraint, none include connection costs, balancing costs and grid costs. Only Fuchs et al. (2017) includes grid expansion costs. As the STEM model employs an hourly intra-annual time resolution of three typical days for four seasons, other Swiss *net zero* cost-optimisation models offer similarly sampled resolutions. Overall, models are found to exhibit similar total electricity generation (between 80 and 90 TWh), while varying in electricity generation technology shares, most visibly solar PV, net imports as well as thermal and combined heat and power (CHP), as shown in Figure ES2.

Figure ES2. **Electricity generation mixes in cost-optimised net zero 2050 scenarios**

(Present report and selected studies, TWh)



Note: LTO = long-term operation; VRE = variable renewable energy; PV = photovoltaic; CHP = combined heat and power.

In terms of costs, *net zero* scenarios that rely on higher shares of generation from VREs and lower net imports tend to exhibit higher overall system costs. Quite intuitively, scenarios including a higher deployment of VRE also exhibit higher levels of storage. While recent studies arrive at similar conclusions regarding the amount of electricity generation required for increased electrification in Switzerland under a net zero carbon constraint for its energy sector, system costs, due to different assumptions regarding imports and carbon capture and storage (CCS), result in varying shares of VRE, storage, thermal power and CHP, and net imports. In Fuchs et al. (2021) increasing nuclear power plant operation to 60 years coupled with net imports is found to represent the least-cost *net zero* scenario. An increase of nuclear power plant operation to 60 years is found to decrease system costs significantly compared to a 50-year scenario. In line with results from past NEA modelling studies (NEA, 2019; NEA, 2012), a review of the literature on Swiss net zero system costs appears to confirm that long-term operation of existing nuclear power plants, limiting reliance on VRE, contributes to lower overall system costs.

Modelling system costs under a net zero carbon constraint with the NEA POSY model

Accounting for the system costs of different generation mixes in order to attain ambitious net zero carbon emission objectives is indispensable for informed energy decision-making. The present report contributes to this effort, assessing the costs of five scenarios with distinct generation mixes capable of attaining net zero carbon emissions with different levels of interconnection capacity. To allow for a full understanding of the results provided below, it is useful to first recall the principal features of system cost analysis as well as to present briefly the NEA POSY model, with which the analysis has been undertaken.

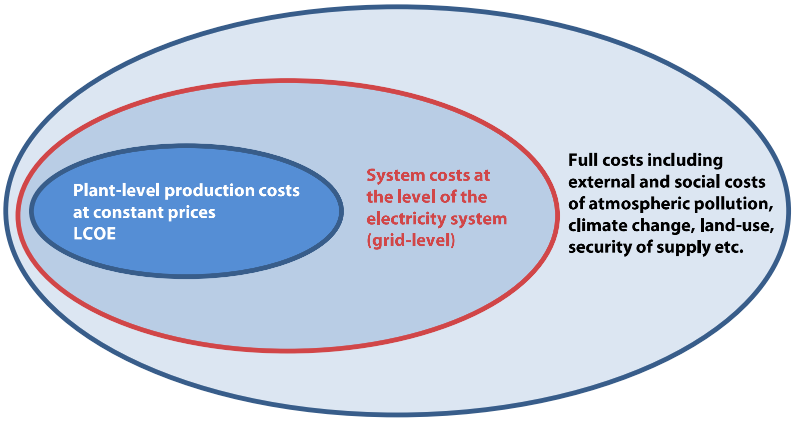
System costs in low-carbon electricity systems

At its most simple, power system costs can be categorised into three groups, as shown in Figure ES3. The most basic element of electricity system modelling is composed of the levelised costs of generating electricity (LCOE) at the plant-level. Introduced in the regulated electricity systems of the 1960s, this methodology provided a simple and intuitive tool to compare the lifetime costs of different baseload generation technologies. By discounting or compounding all lifetime costs for capital and operations to the date of commissioning and dividing their sum by the total discounted lifetime revenues, regulators disposed of a handy gauge for the costs of each technology per unit of output. To guarantee comparability, usually identical load factors and discount rates were employed across technologies. While the LCOE methodology can be and has been severely criticised for the stilted nature of its assumptions and its inability to take into account system interactions, it continues to provide a simple and immediately understandable starting point for more complex cost assessments.

Yet for all its qualities as a pragmatic tool, the limits of relying on the LCOE methodology alone became obvious with the advent of variable renewable energies such as wind and solar PV. All technologies impose some additional costs at the system level that are not accounted for in LCOE calculations. Nuclear and coal, for instance, have specific siting requirements due to cooling needs or require special grid characteristics for the outlay of transmission system. While these added costs at the level of the grid-based system are relatively small compared to the overall costs of generation, the variability and uncertainty of wind and solar PV generation introduces effects of a different magnitude.

In particular, the variability of wind and solar PV forces analysts, planners, regulators and policymakers to adopt a system perspective. No matter how much solar PV capacity is installed, some dispatchable capacity is required to meet electricity demand at night. That dispatchable capacity, however, will run at lower load factors and hence higher average costs per unit of output than otherwise thus raising the costs of the system as a whole. In the language of system cost analysis this is referred to as profile costs. To **profile** costs, by far the largest component of electricity system costs, there must also be added **balancing** costs, arising from the uncertainty rather than the variability of electricity generation, **grid** costs in the form of added outlays for transport and distribution, which can be significant for decentralised renewables, and **connection** costs, to connect a power plant to the nearest bus of the transmission grid.

Figure ES3. **Major cost categories in electricity systems**



Accounting for profile and balancing costs in a systematic manner requires the use of linear optimisation models with at least hourly granularity. Different modelling efforts will subsequently be differentiated by the number of technical constraints they are able to accommodate, the representation of non-adjustable (brownfield) elements of the system, the estimation of electricity demand, the taking into account of electricity trade as well as the pertinence of the policy constraints that are formulated.

NEA (2012) provided first insights into the relative system costs of different generations mixes, while NEA (2019) provided a first systematic modelling of generation mixes with different shares of nuclear energy and VRE under the same stringent carbon constraint. The current report is the first of a series of co-operations between the NEA and its member countries in assessing the costs, challenges and opportunities for their energy systems in a context of increasingly stringent carbon constraints.

The NEA POSY model

Methodological advances and technological progress in computing power and modelling software have allowed for a broader adoption of tools for analysing the costs of integrated electricity systems. These regard in particular models using mathematical techniques such as linear programming (LP), and mixed-integer linear programming (MILP) to solve the cost minimisation problem involved in jointly optimising long-term capacity investment and short-term dispatch.

Standard linear programming focuses on solving problems in which the objective functions, for instance the production profile of a generation plant, are linear and constraints are thus specified using only linear equalities and inequalities. MILP models instead solve linear programmes in which variables can be constrained to take on integer values. In the context of an electricity system this may imply, in its simplest form, that a plant cannot produce at hour $n+1$ at full capacity (or must produce at a certain level) if it has not produced (or has produced) at hour n. MILP is thus designed to solve far more complex problems than regular LP and substantially increases the technical realism of the electricity system studied. A convincing representation of unit commitment is possible only with MILP, which today constitutes the state of the art in advanced electricity sector modelling.

The POSY MILP model was developed within the NEA to allow the assessment of the system costs of different constellation of integrated low-carbon systems. With 8 760 time-steps per year it has an hourly representation that is sufficient to capture profile costs, even if balancing costs might benefit from a higher temporal resolution, although differences are second-order. As other MILP models, it produces optimised mixes and generation profiles under a set of exogenously formulated policy constraints. The strength of the present modelling effort is based in particular on a careful representation of the Swiss electricity system established in co-operation with experts from the electricity industry and academe. This involved a careful calibration and validation of POSY in the year 2019, the last year before the COVID-19 pandemic, to capture the structural determinants of the Swiss electricity sector that then informed the modelling of the assumptions and constraints formulated for 2050. See Chapter 3 and Annex 1 for a full presentation of POSY's features.

The system costs of five net zero scenarios in 2050 in Switzerland

Switzerland's large hydroelectric capacity and high level of interconnections for electricity trading provide a solid foundation towards the objective of net zero carbon emissions in 2050. Hydroelectricity and imports alone, however, will be unable to fulfil all low-carbon electricity needs, in particular as transfers from other sectors such as heating and transport will significantly increase Swiss electricity demand by 2050. The key energy policy question is then which low-carbon technologies will provide the remainder of electricity supply. In the following are presented two viable and policy-relevant scenarios that could allow Switzerland to attain net zero carbon emissions while safeguarding the security of electricity supply (see below). Three additional scenarios have been added for comparison purposes only and are not foreseen in the country-specific strategy. Each scenario is analysed with different levels of interconnection capacity, which remains a crucial determinant for the total system costs of the Swiss electricity sector (see also Figure ES4).

a) The **LTO** scenario assumes that in addition to the existing hydro capacity, Switzerland will dispose of 2.2 GW of nuclear capacity from the LTO of the two nuclear reactors at Gösgen and Leibstadt. Such LTO would, of course, depend on fulfilling the safety retrofits required by the regulator, the Swiss Federal Nuclear Safety Inspectorate (ENSI), and the viability of the plants. In addition to the 2.2 GW of nuclear baseload capacity, the POSY model generates as much solar PV and wind capacity as required complemented by the necessary flexibility resources.

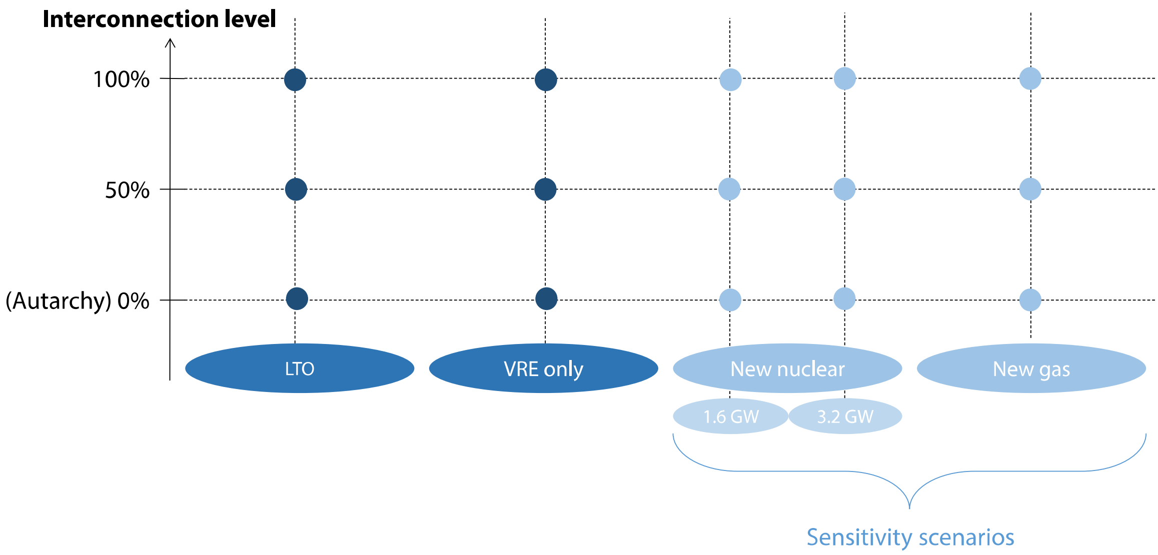
b) In the **VRE only** scenario, the POSY model generates in addition to existing hydroelectric facilities as much solar PV and wind capacity required, as well as flexibility resources to satisfy the supply constraint. Given the realities of the Swiss policy debate, solar PV was assumed to contribute 90% of VRE generation and wind 10%. The same distribution was applied to the VRE contribution in other scenarios.

c) The **New nuclear 3.2 GW** scenario assumes that two new Generation III+ nuclear reactors will provide 3.2 GW of nuclear baseload in 2050. On the other hand, there would be no nuclear LTO in this case. The remainder of the required low-carbon electricity would again be provided by solar PV and wind. There is currently no legal basis for nuclear new build in Switzerland, so this scenario must be considered a pure thought-exercise for comparison purposes only.

d) The **New nuclear 1.6 GW** scenario assumes that only one new Generation III+ nuclear reactor will provide 1.6 GW of nuclear baseload. The rest of the required low-carbon electricity would again be provided by solar PV and wind. There would also be no nuclear LTO in 2050. The same disclaimer as in the New nuclear 3.2 GW scenario applies.

e) The **New gas** scenario assumes the construction of 2 GW of gas-fired capacity and the implementation of a carbon price of USD 100 per tonne of CO_2. The balance of electricity needs is again provided by VRE. The scenario contains no nuclear power. Given the opportunity cost of the high carbon price in this scenario, it can be assumed that CO_2 emissions would either be abated, for instance through CCS, or compensated, for instance through reforestation schemes in non-European countries and that thus the net zero constraint would continue to be respected. New gas capacity, however, is not part of any official strategy but presented here for comparison purposes.

Figure ES4. **Considered scenarios of the study for reaching *net zero* target**



The LTO and VRE only scenarios are the two central scenarios analysed in this report. The primary function of the nuclear new build and new gas scenarios is to provide further cases for comparison rather than to provide alternatives to key scenarios. The five aforementioned scenarios of the Swiss electricity sector in 2050 have been modelled by the NEA's POSY MILP optimisation model in three different trade constellations:

1) Swiss interconnection capacity in 2050 will be 100% of its 2022 level and trade relations with the European Union in the electricity market continue without change;

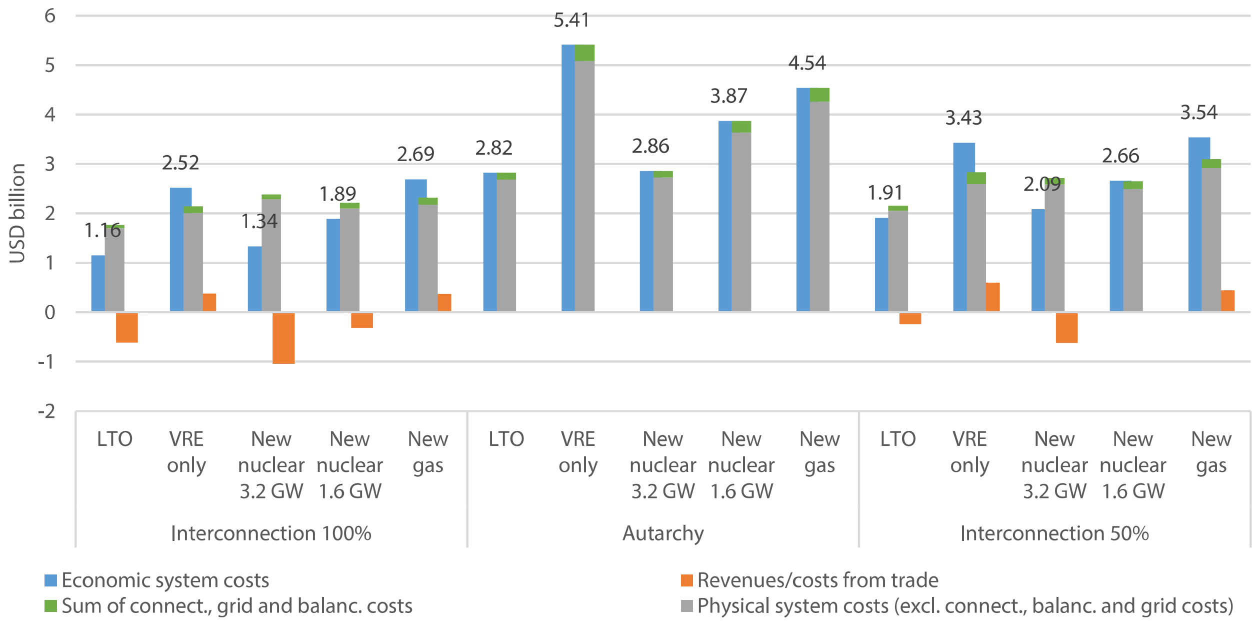
2) Swiss interconnection capacity in 2050 will be reduced to 50% of its 2022 level thus limiting but not terminating electricity exchanges with its European neighbours;

3) Switzerland will attempt to attain net zero emissions in autarchy, i.e. all interconnections with neighbouring countries will be closed.

Combining five scenarios with three levels of interconnection capacity yields 15 cases that have then been analysed with the POSY model. Figure ES5 provides an overview graph of the total system costs and its different components. Economic system costs, are equal to the domestic generation costs (physical system costs) *minus* net trade revenues. Positive net trade revenues are indicated in orange as negative costs. In the rare cases that Switzerland would have a net trade deficit in electricity trade, this would appear as a positive cost. The physical system costs includes also in green the sum of connection, grid and balancing costs. The numerical value indicated on each bar of the graph refers to the economic system cost.

Figure ES5. **System costs of the five net zero scenarios under different trade constellations**

(USD billion)



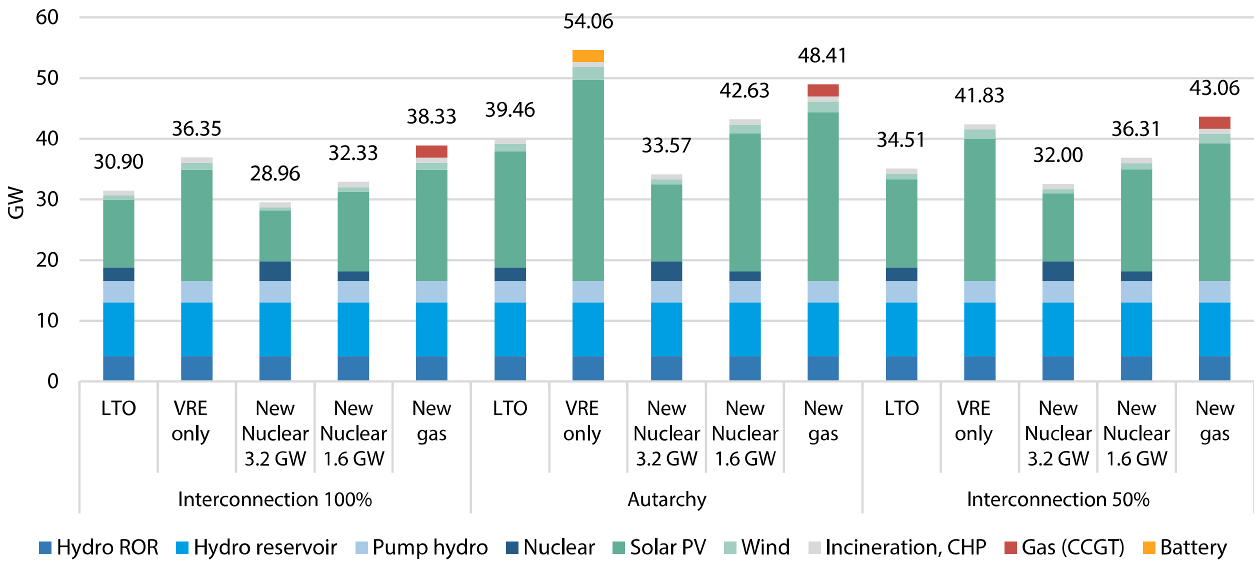
Note: Economic system costs equal physical system costs minus trade revenues plus sum of connection, grid and balancing costs. LTO = long-term operation; VRE = variable renewable energy.

The results show that the most cost-effective option to reach Switzerland's net zero objective in 2050 is to continue operating its two youngest nuclear power plants, Gösgen and Leibstadt, as well as to maintain the level of interconnection capacity for electricity trading with its neighbours at current levels. Long-term operation of 2.2 GW of nuclear capacity would also be the most cost-effective option under autarchy or with reduced interconnections capacity. The LTO scenario has, in particular, lower economic costs than the VRE only scenario, less than half indeed if levels of interconnection capacity are kept at current levels. Figure ES5 further shows that regardless of which electricity generation mix Switzerland decides to adopt, it is always economically more efficient to maintain interconnection capacity at current levels, rather than seeing them reduced or even to close them entirely. Autarchy is always, by some distance, the least-best option.

The third observation is that other than continuing the operations of Switzerland's two youngest nuclear power plants, new nuclear power plants would be the alternative scenario with the lowest economic costs to achieve *net zero*. In all three trade constellations, two new nuclear power plants with 3.2 GW would be more cost-effective than only a single new 1.6 GW plant. Due to the round-the-clock generation of low-carbon electricity, which frees flexible hydro capacity for arbitraging electricity trade flows, the comparative advantage of higher baseload capacity is particularly relevant in the two scenarios with electricity trading. Results for the total system costs of the different scenarios in Figure ES5 are complemented by the corresponding capacity and generation mixes in Figures ES6 and ES7.

Figure ES6. **Capacity mix of the five net zero scenarios under different trade constellations**

(GW)

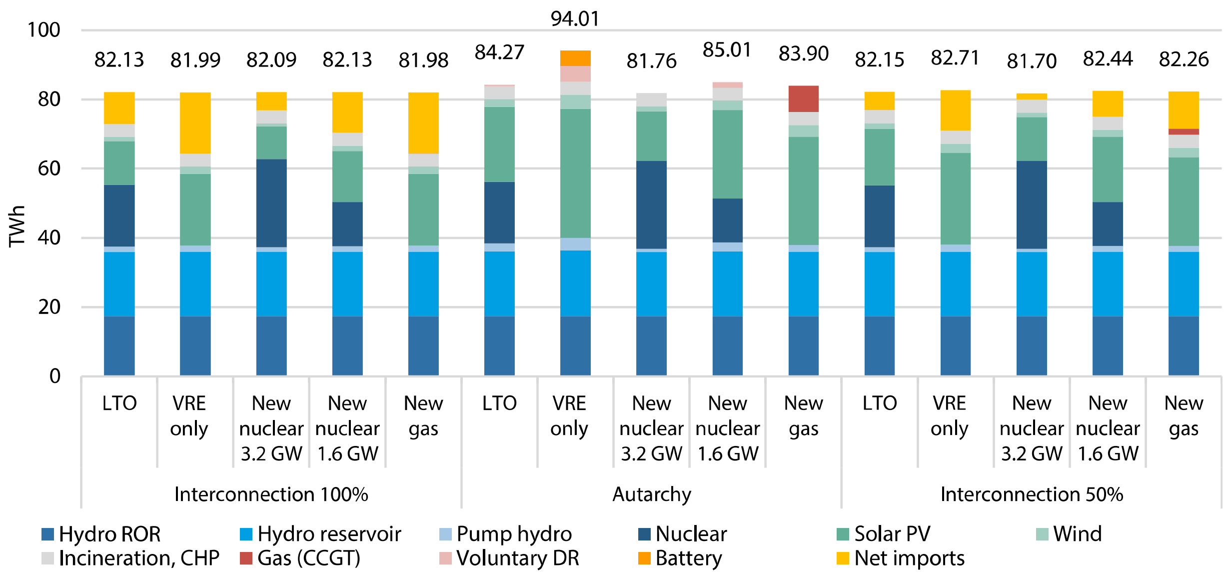


Note: LTO = long-term operation; VRE = variable renewable energy; ROR = run-of-the-river; PV = photovoltaic; CHP = combined heat and power.

It is immediately visible that high shares of solar PV and wind in the generation mix increase total capacity, which is due to their comparatively low load factors. This may make land use an issue in the Swiss energy debate. In addition, in the autarchy scenario, the absence of interconnection capacity as a flexibility resource requires the adoption of new flexible capacity such as demand response (see Figure ES8) or batteries. Their additional costs provide a first indicator of the stress to which the Swiss electricity system would be subjected in the autarchy scenarios.

Figure ES7. **Generation mix of the five net zero scenarios under different trade constellations**

(Gross production, TWh)



Note: LTO = long-term operation; VRE = variable renewable energy; ROR = run-of-river; PV = photovoltaic; CHP = combined heat and power.

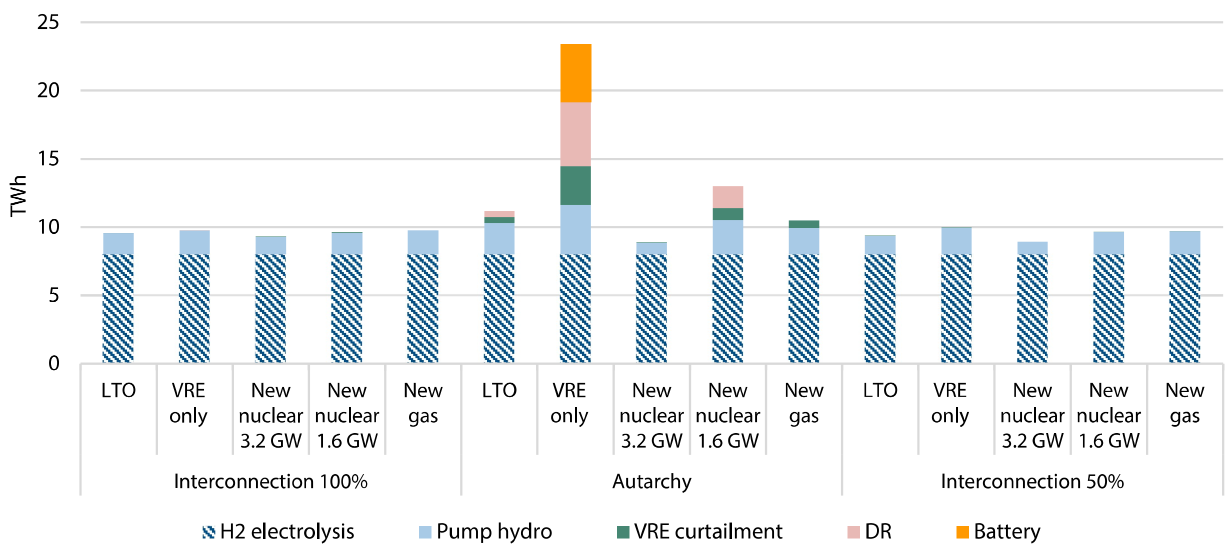
Regarding generation, the main observation is that electricity imports play an important role. In all five net zero scenarios with open interconnections, Switzerland imports more physical electric energy than its exports. Nevertheless, it has a positive trade balance in most scenarios due to its ability to buy electricity when prices are low and to sell it when they are high. Physical net imports are highest in the VRE only scenario, as in this case the flexibility needs are greatest. Net imports are lowest in the LTO and New Nuclear scenarios with their constant round-the-clock generation of baseload electricity.

Results from the POSY model also show the crucial role of flexibility provision when advancing to net zero carbon emissions by 2050. Flexibility provision in electricity systems is primarily characterised by the ability to react quickly to changes in demand or in the load provided by other generators, whether foreseen or unforeseen. In this regard, Switzerland is fortunate to dispose of a large set of low-carbon flexibility providers.

Switzerland's 3.58 GW of hydro pump storage facilities are the bedrock of its domestic flexibility provision. In addition, more than 10 GW of interconnection are an extremely important source of flexibility. Together these two flexibility sources allow for system constellations that could not be realised in countries with less abundant flexibility resources. Curtailment of VRE generation, i.e. the temporary disconnection of solar PV or wind capacities from the grid, provides further flexibility. They are complemented by 1.4 GW of voluntary demand response, i.e. electricity customers willing and capable of shedding load, against remuneration, during times of need, as well as batteries. Finally, the 2050 system foresees flexible hydrogen production on the basis of water electrolysis with proton exchange membrane (PEM) electrolysers at a level of 8 TWh per year that can be switched on or off according to system needs. Figure ES8 gives an overview of the composition of flexibility provision in the different scenarios.

Figure ES8. **The contribution of different flexibility providers in each scenario**

(TWh)



Note: LTO = long-term operation; VRE = variable renewable energy; DR = demand response.

Quite intuitively, the greatest flexibility needs arise in a VRE only scenario under autarchy. Future energy policy debates must thus not only answer the question of which low-carbon technologies other than hydro will provide the bulk of Switzerland's electricity needs under different scenarios, but also which technological and market design options are most apt to provide the large amounts of flexibility required. It should be highlighted that POSY modelling in the present report concentrated on the economic costs and viability of the different scenarios. Further research on the technical feasibility of extreme scenarios presenting never before encountered challenges for systems operations might provide further insights.

Conclusions

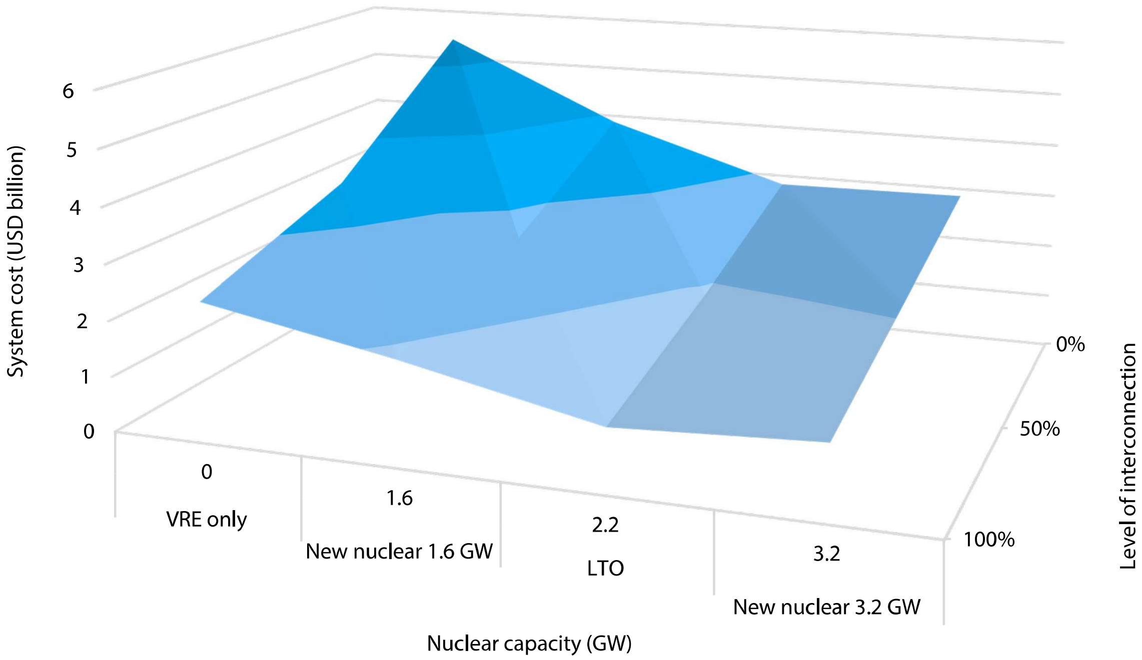
Switzerland currently enjoys a secure, low-carbon electricity system. The reliability of its baseload nuclear power and run-of-the-river hydropower plants, as well as its large interconnection capacity, allows flexible hydro reservoirs and pump storage units to engage in profitable electricity trading with its neighbours. The present study aims at providing insights around three robust conclusions based on a transparent and sound methodology to achieve net zero carbon emission by 2050.

First, scenarios built on a generation mix of renewables *and* nuclear baseload have consistently lower system costs than scenarios based exclusively on variable renewables such as solar PV and wind. The analysis shows that most cost-effective scenario to reach net zero carbon emissions in 2050 is to engage in the LTO of the two youngest Swiss nuclear power plants, while maintaining 2022 levels of interconnections capacity for electricity trading with its neighbours.

Second, while more expensive, Switzerland's high level of domestic flexibility resources renders a VRE only strategy technically feasible as long as the level of interconnection capacity allowing for electricity trade with neighbouring countries remains at today's levels. Sufficient interconnection capacity remains critical for the Swiss security of electricity supply. Just as today, Switzerland will continue to be a net importer of electricity in physical terms in all scenarios allowing for electricity trading. This assumes that electricity systems in neighbouring countries will develop sufficient levels of capacity and flexibility resources to supply the required electricity. As shown in the autarchy scenarios, developing such capacity and flexibility domestically is, however, always considerably more costly.

Figure ES9 briefly summarises the total system costs of different scenarios grouped along two axes, the amount of nuclear generation capacity and the degree of interconnection between Switzerland and its neighbours. It shows that a higher degree of interconnection always reduces system costs. It also shows that LTO of Switzerland's two newest nuclear power plants is the most cost-effective solution in terms of the contribution of nuclear power to achieving net zero. However, even incurring the fixed cost for new nuclear capacity would be more cost-effective than a VRE only strategy.

Figure ES9. **Total system costs as a function of nuclear capacity and interconnection level**



Note: For expositional purposes the "new gas" scenario was excluded from this figure.

Third, a VRE only strategy to reach net zero in 2050 in autarchy would not only be very expensive but would also move the Swiss system away from security of supply resilience despite the high level of Swiss domestic flexibility resources. The feasibility of such a scenario relies on the constant availability of all flexibility resources, including a substantial level of flexible hydrogen production, with little residual capacity to absorb unforeseen shocks. Furthermore, in such a scenario, the amplitude and frequency of oscillations would be considerable (see Annex A for details). Hence additional testing of the technical feasibility of the VRE only scenario in autarchy would be welcome.

These three key results developed on the basis of reasonable assumptions and a sophisticated modelling tool, which is fully presented in the following report, appear robust. They will constitute the parameters of the future energy policy debates that Swiss politicians, energy decision-makers, stakeholders and consumers will need to have in the years to come to ensure achieving a net zero target by 2050 while preserving current levels of security of supply and economic efficiency.

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Chapter 1: **The Swiss energy policy context and carbon emission objectives**

1.1. **Introduction**

This report by the Nuclear Energy Agency (NEA) studies different scenarios under which Switzerland can achieve its ambitious objective of net zero carbon emission in 2050. To this end, it establishes the total system costs of five low-carbon generation mixes in the Swiss electricity sector. A key feature differentiating the scenarios is the relative contribution of nuclear energy and variable renewables, in particular solar PV, to electricity supply in 2050.

During the preparation of this report it was well understood that the current central scenario of the Swiss energy strategy aims at reaching net zero by relying primarily on solar PV and a small share of wind, as a complement to hydroelectricity and electricity imports, on the assumption that the Swiss nuclear power plants will have been closed before 2050. Swiss law does not allow for the construction of new nuclear plants, however, it also does not limit the duration of the operations of existing nuclear plants. Analysing the potential contribution of the long-term operation of the two youngest Swiss nuclear plants in a perspective of achieving net zero in 2050 in a cost-effective manner is thus part of the lively and wide-ranging Swiss energy policy debate that will be briefly synthesised in this introductory chapter. Needless to say, under all circumstances, nuclear energy would contribute to low-carbon electricity generation alongside the contribution of substantial amounts of new solar PV and wind capacity as well as the ongoing contribution of Switzerland’s large hydropower reserves.

With the lowest carbon intensity and second-lowest energy intensity of all NEA member countries, having achieved decoupling of energy consumption from economic growth, Switzerland is well positioned to achieve net zero carbon emissions by 2050. However, Switzerland’s net zero ambition is also deeply interdependent with its current and future energy policy. Presently relying on low-carbon electricity generation from its hydropower and nuclear power plants, achieving net zero while foreseeing a nuclear phase out and integration of its electricity market with Europe’s may provide challenges and opportunities. Although consensus towards the need to achieve net zero exists in Swiss government and society, less consensus is apparent on pathways towards that goal. The main features of the Swiss energy policy debate will now be presented with special attention to the role that nuclear energy is supposed to play in achieving net zero.

Despite a long tradition of successful nuclear power production, Switzerland voted to no longer allow construction of new nuclear power plants in 2017. However, over several referenda, Switzerland also voted not to limit the duration of operation of existing nuclear power plants – cautiously rejecting calls to change overnight a generation system supporting energy security, low-carbon electricity, and net zero emissions. Although an EU-Swiss electricity agreement remains unlikely in the near term, due to the country’s geographical location and large hydropower reserves, Switzerland is expected to continue playing an important arbitraging role in electricity markets, relying on greater market integration to help achieve net zero objectives. However, Switzerland may also face challenges in securing its electricity supply in the mid- to long term, especially if Swiss nuclear power plants are retired earlier than their operationally feasible duration. While renewable energy generation is increasing in Switzerland, alongside imports, further investments appear necessary to achieve generation targets and maintain security of supply. Swiss nuclear power plant operation beyond 60 years could prove both a cost-effective contribution for Switzerland to achieve net zero in 2050 and help decrease imports that would likely be required to maintain electricity supply if nuclear power plants go offline.

Assessing past and present policies, Swiss electricity generation and carbon emission reduction goals are deeply intertwined with, and often balanced by differing federal, popular, and cantonal stances. Despite a federal basic assumption of a 50-year operation of nuclear power plants post-Fukushima, in 2021, given possible uncertainty surrounding security of Swiss electricity supply, a shift towards a 60-year nuclear power plant operating period was observed in informal federal policy, utility plans and academic models. The emerging energy security challenges Switzerland faces are not easily resolved by renewable energies in the short to medium term – reflected by federal considerations to build temporary gas-fired power plants. In the long term, several studies also find the relatively untested roles of domestic and foreign carbon capture and storage (CCS) necessary to attain the desired emission reductions. Finally, the unrealised revision of Switzerland's CO_2 Act also showcase the boundaries of policy as a predictable indicator to further reduce carbon emissions. With all technologies available at the table, including nuclear energy, achieving net zero may become more attainable. In a context of uncertainty over security of electricity supply, financing limits, and net zero goals, the aim of the present study is an assessment of unexplored pathways to net zero and their associated costs, to further inform stakeholders in the Swiss energy realm.

1.2. Swiss energy policy pre net zero

Before 1973 there existed no constitutional basis for Switzerland's government to draft a national or cantonal energy policy. Electricity companies, primarily owned by the public sector, were only obliged to ensure electricity supply in their service areas (Fagagnini, 1977). In the early 1960s, as existing Swiss hydropower capacities were viewed as largely exhausted, the Federal Council sought to develop nuclear energy to meet growing demands for electricity (SFOE, 2020a). Utilities proposed building coal and oil-fired plants but the Swiss government encouraged them to plan for nuclear power (WNA, 2022). In its 1963 annual report, the Federal Council included in its programme the statement that water and atomic energy would be built into a rational system complementing one another – outlining Switzerland's future and current low-carbon electricity mix defined by hydropower and nuclear power. Switzerland's first commercial reactors were Beznau I – a 365 MW pressurised water reactor (PWR) ordered by Nordostschweizerische Kraftwerke AG in 1965 and soon after duplicated with (Beznau II), and Mühleberg – a similar-sized General Electric boiling water reactor (BWR) ordered by Bernische Kraftwerke AG in the same year (WNA, 2022). Mühleberg eventually shut down in 2019 following a complex case largely based on grounds of safety and associated costs for additional investments – nonetheless, citizens in Bern rejected a vote to prematurely shut down the plant (WNA, 2022). The 1973 oil crisis and its aftermath spurred the adoption of energy policies in several European countries – including Switzerland. The Federal Council assigned to a Federal Commission the design of an Overall Energy Concept (GEK) to formulate Swiss energy policy goals, based on the expansion of nuclear energy, ambitious energy efficiency targets and energy research (Rieder and Strotz, 2018).

While renewable energies were considered in the context of the GEK, development of nuclear energy and savings in consumption were viewed as more effective (Rieder and Strotz, 2018). Nuclear energy was expanded further in the 1970s as a key pillar in the GEK, supporting the construction of the Leibstadt, Gösgen, and Kaiseraugst plants among additional nuclear power plant projects (Jegen, 2003). However, plans for Kaiseraugst would eventually be abandoned in 1988 after anti-nuclear opposition following the Chernobyl accident (WNA, 2022). A consortium of utilities ordered a large PWR from Siemens for Gösgen in 1973, and the same year another consortium ordered a similar-sized General Electric BWR for Leibstadt (WNA, 2022). Although anti-nuclear initiatives arose following their construction, the initiatives were rejected (Jegen, 2003). To grant the federal government greater ability to draft a national energy policy, the creation of a constitutional article granting powers to introduce an energy levy and take measures in the areas of energy savings and research was introduced in 1983 (Rieder and Strotz, 2018). However, the Federal Commission for the Overall Energy Concept (GEK) initially was unable to conclude a consensus-based proposal for a national energy policy and the first constitutional amendment vote was rejected, largely due to resistance from Switzerland's cantons (Kriesi and Jegen, 2001).

The Chernobyl reactor accident in 1986, the Brundtland Report of 1987, and the 1988 *International Conference of the Changing Atmosphere: Implications for Global Security* in Toronto gave greater weight to environmental movements, influencing Swiss energy policy (Rieder, 1998). A ten-year moratorium on the construction of new nuclear power plants was supported by 54.6% of the electorate in the popular initiative "Stopping the construction of nuclear power plants" of 1990, leading to passing of the Federal Act on Transitional Disposition, banning new licences for ten years (WNA, 2022; IEA, 2000). A new constitutional article was also drafted by the GEK in 1990 covering energy policy goals – including ensuring an adequate, diverse, secure, economical, and environmentally friendly energy supply and giving the federal government more power to influence expansion, production, and conservation of energy (Rieder and Strotz, 2018). In 1990 the Swiss public voted in favour of granting the federal government a constitutional energy mandate, previously a largely cantonal affair (Baal and Finger, 2019). The federal government also gained the power to issue regulations for energy consumption, vehicles and devices, and design support programmes, especially for renewable energy (Rieder and Strotz, 2018). Based on the successful outcome of the second vote in 1990, the Federal Council designed the first national energy policy programme, Energy 2000, aiming to stabilise electricity consumption, reduce fossil fuel use, increase supply of renewable energies, increase the capacities of existing nuclear power plants by 10% between 1990 and 2000, and stabilise CO_2 emissions (IEA, 2000). The first energy act (*Energiegesetz*) passed in July 1998 and entered into force from 1999 to 2018. The first CO_2 Act was also passed in January 1999, aiming to reduce CO_2 levels by 10% of 1990 levels.

Box 1.1. **Cantons and Switzerland's energy policy implementation**

Switzerland's federal structure of 26 cantons and its use of the subsidiarity principle, devolving policy implementation to the lowest levels of its political system, can complicate energy and climate policy goals (IEA, 2018). While the federal state is responsible for energy issues of national importance such as nuclear safety, oil and gas infrastructure, CO_2 taxation, and efficiency standards, cantons set their own energy policies (IEA, 2018). The Conference of Cantonal Energy Directors has agreed on a set of joint model cantonal provisions for energy, aiming to harmonise cantonal legislation relating to energy efficiency (SFOE, 2020b). However, structures and measures promoting energy efficiency or renewable energy differ from canton to canton. Cantons are primarily responsible for defining suitable regions for renewable energy, the licensing of power plant facilities within respective cantonal frameworks, and energy planning – often being the sole or a co-owner of energy companies (SFOE, 2020b). The role cantons and municipalities play in the planning and approval process, especially for renewable energy projects, is significant for the implementation of Switzerland's net zero goals (Rieder and Strotz, 2018). Cantonal influence on Swiss energy policy, often through its Council of States, is also visible in a historical water tax, the Wasserzins, a levy hydropower producers pay cantons for water use.

Central to Swiss energy policy lies a complex interplay between citizens' voices, federal and cantonal policy, plans of Swiss utilities, neighbouring countries, and the EU. Nuclear energy is featured frequently at the heart of Swiss energy debates, as well as hydroelectric power – the two comprising nearly 94% of the country's electricity production (FDFA, 2019). Decisions to build new nuclear power plants or phase out nuclear power production have been frequently decided on somewhat narrow majorities in the context of shifting policy priorities and public sentiment. Decisions are also regularly intertwined with questions regarding respective competencies of the federal government, cantons, and Switzerland's degree of economic integration with the EU – especially considering its increasingly deregulated electricity market. While the latter offers Switzerland's flexible hydropower an opportunity to arbitrage between varied generation structures of its European neighbours, integration with Europe, including electricity market integration, is perceived by certain Swiss constituencies as a loss of national autonomy and an added source of uncertainty.

As early as the 1990s, the European Union (EU) began efforts to establish complete market liberalisation and an internal European electricity market. In response, Switzerland drafted its own legislation, an electricity market law intended to tie Swiss and EU energy markets; however, the Swiss trade union confederation held a successful referendum against the market law – rejected in 2002 (Sager, 2014). Arguments related to political and economic sovereignty, and less to energy policy were seen to influence the vote (Rieder and Strotz, 2018). In a 2003 referendum, Swiss voters rejected two additional anti-nuclear proposals. One (by two-thirds) to phase out nuclear power by 2014, and the other (by 58%) to remove incentives to invest in and upgrade nuclear power plants – nearly all cantons refused both (WNA, 2022). Across this initial period of Swiss national energy policy, it is evident that both support and opposition for nuclear power was nuanced.

Box 1.2: **Switzerland's "autonomous" EU electricity market integration**

Switzerland was one of the early drivers of European integration in the electricity sector. In 1958, the "Star of Laufenburg" substation in the Aargau canton first connected the electricity grids of France, Germany, and Switzerland (Baal and Finger, 2019). While a liberalisation law, the Electricity Market Law (EMG) was proposed in the early 2000s, it was rejected in a 2002 referendum (Jegen, 2009). As Switzerland is not a member of the EU, rejection could be seen as Eurosceptic, as the EMG meant to assimilate Swiss domestic policy with the EU's (Baal and Finger, 2019). However, an Italian blackout originating on the Swiss border in 2003, causing 56 million people (largely Italians) to be left without electricity and an estimated EUR 1.2 billion in economic damages, placed international and domestic pressure on Switzerland to reconsider market liberalisation and integration (Walker et al., 2014). In 2004, Swiss companies voluntarily agreed to merge several transmission grids into a single control area under the transmission system operator (TSO) Swissgrid (D'Arcy and Finger, 2014). By proactively forming Swissgrid on the TSOs terms, Switzerland could better determine its own rules for both liberalising its electricity market and integrating it with the EU (Baal and Finger, 2019). In 2007 the Electricity Supply Act, or StromVG was approved, partially liberalising Switzerland's electricity market – currently only large consumers (> 100 MW) can choose their electricity supplier (SFOE, 2010).

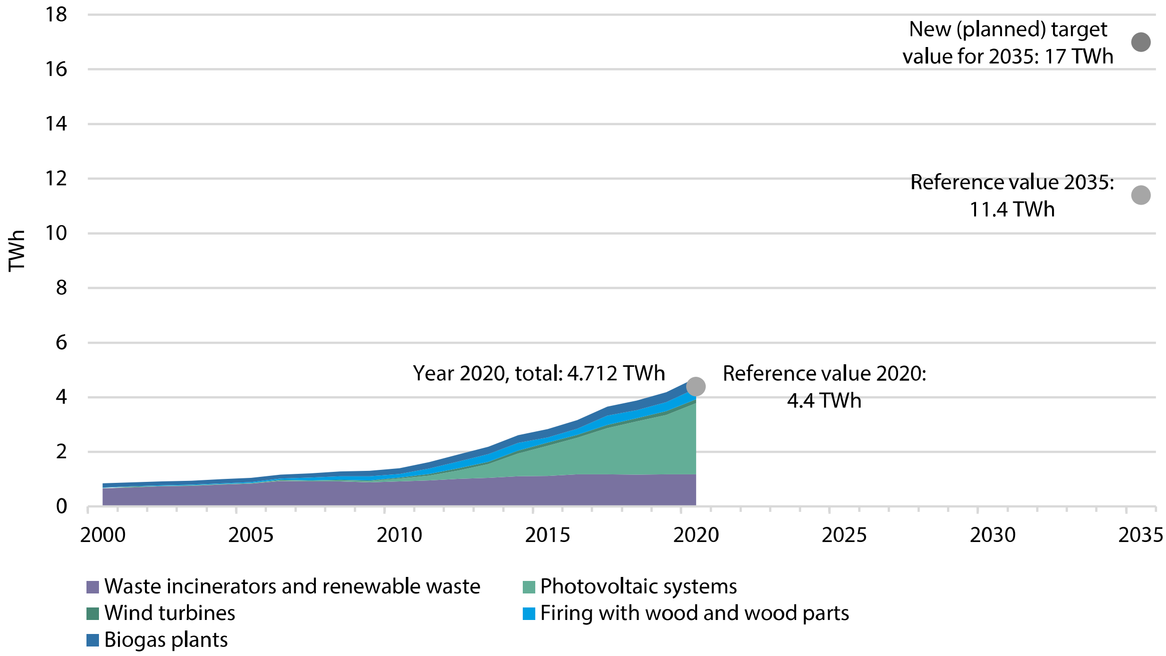
The Swiss electricity grid remains an integral part of the European grid – Switzerland thus has 41 electricity interconnectors with EU member neighbours (Thaler and Hoffman, 2022). To level grid fluctuations cost-effectively, activation of balancing reserves across these interconnections is significant (Schillinger, 2020). Furthermore, Swiss hydropower provides valuable storage services for EU electricity transits (helping increase profitability for Swiss hydropower), and access to a greater EU electricity market could increase the attractiveness of investments in Swiss renewables (Thaler and Hoffman, 2022). Given its large natural storage capacities, and geographically advantageous position for EU electricity transits, Switzerland may achieve strategic benefits from further liberalising and integrating its electricity market. However, while Switzerland and the EU are highly interdependent on energy given Switzerland's geographical position, there exists low policy alignment without a formal EU-Swiss energy agreement (Stromabkommen) and without a Swiss legislative equivalent to the EU energy acquis – consisting of adopting core EU energy legislation (Baal and Finger, 2019). Both Switzerland and the EU thus greatly benefit from the interconnection of their electricity systems. The challenges of decarbonsing their respective generation mixes will further enhance those benefits.

Full market opening was anticipated for 2015, but negotiations with the EU regarding a bilateral agreement for electricity market integration halted in 2014 when Switzerland voted to limit immigration from EU countries (IEA, 2018). Until a bilateral electricity agreement is signed, Switzerland is excluded from participating in major EU market coupling mechanisms, increasing the need for re-dispatching power in Switzerland (Baal and Finger, 2019; Swissgrid, 2018). A technical approach (negotiated bilateral contracts) has arisen ensuring a minimum level of Swiss-EU co-operation sufficient for basic energy security (ElCom, 2020). However, future EU regulations may limit the efficacy of bilateral contracts, and the ability of Switzerland to secure competitive prices (Grünewald et al., 2021). As from 2025, all European TSOs must reserve at least 70% of cross-border network capacities for EU member states, Switzerland may see its import capacity reduced (Frontier Economics, 2021). Ensuring network stability under bilateral contracts may also require temporary restriction of Swiss exports and imports (ElCom, 2020a). A 2021 combined study by ElCom, Swissgrid, and Frontier Economics assessing security of electricity supply found that if no bilateral agreements are reached by 2025, in the worst-case scenario Swiss electricity needs may no longer be covered for 47 hours during the winter (Frontier Economics, 2021).

In 2021 the Swiss government decided to formally stop institutional negotiations with the EU. Institutional questions unrelated to energy (more political and economic integration into the EU) arose as obstacles impeding a Swiss-EU electricity agreement (Thaler and Hoffmann, 2022). Cantons also appear wary of EU state aid rules – accepting an agreement could mean existing market premiums for Swiss hydropower would become incompatible with EU state aid rules (Van Baal et al., 2019). It is unclear whether an agreement is possible within the next five years (Grünewald et al., 2021). To maintain market access in key areas, the Swiss government appears to be "adjusting autonomously" to EU legislation (Thaler and Hoffmann, 2022). As energy costs rise due to geopolitical tensions, a long-term relationship with Europe awaits clarification. A complete phase out of Swiss nuclear power, likely requiring an increase in imports to secure electricity supply, risks further complicating this equation.

In 2007 a new bill surrounding market liberalisation, the Electricity Supply Act (StromVG), was passed by Swiss Parliament with no referendum, ushering in a gradual opening of Swiss electricity supply (Rieder and Strotz, 2021). From 2009, the federal government was also able to select producers of domestic renewable electricity, compensating small hydropower, PV, wind, geothermal, and biomass producers with a feed-in remuneration at cost, or KEV (SFOE, 2021a). With the introduction of the KEV, financed by a capped surcharge on consumers, production of renewable energy began to increase in Switzerland, with subsidies for renewables increasing from USD 235 million in 2012 to USD 527 million in 2016 (Rieder and Strotz, 2021). In the early 2010s, renewable energies (excluding hydropower) represented less than 3% of Swiss production, compared to 10% in 2021, while an exponential growth is expected in the near future as shown in Figure 1.1 (SFOE, 2021b; SFOE, 2021c).

Figure 1.1. **Development of electricity production from renewable energy sources (excluding hydropower) since 2000 (GWh)**



Source: SFOE, 2021b.

Since 2004, the Federal Council began to draft and align energy policy with the Energy Perspectives 2035 (EP2035) report, focusing on energy efficiency, renewable energy, replacement and construction of new power plants (including nuclear power plants), and foreign energy supply (WNA, 2022). In the EP2035, a 60-year nuclear power plant operation is assumed for Gösgen and Leibstadt, the newest nuclear power plants, and the scenario employing construction of new nuclear power plants to secure electricity supply until 2035 is found to be the most cost-effective (Prognos, 2007). Due to anticipated scarcity of electricity supply, in 2007 the Swiss government announced that its five existing nuclear power reactors should be replaced with new units – Solothurn canton called for rapid construction of a nuclear power plant – Swiss utilities formed a joint planning company to construct three reactors, and the Federal Nuclear Safety Inspectorate (ENSI) approved their site suitability (WNA, 2022).

1.3. Post-Fukushima Daiichi nuclear power plant policy shift and ES2050 launch

The federal government's energy policy markedly shifted in 2011 due to aims to reduce residual risks from nuclear power plants following the Fukushima Daiichi reactor accident, as well as perceived disadvantages of future costs for electricity generation from nuclear power (Swiss Federal Council, 2011). The Swiss federal government thus suspended ongoing general licence procedures to replace nuclear power plants (Sager, 2014). In 2011 the Federal Council introduced an updated Energy Strategy 2050 (ES2050), including a phase out of nuclear energy. The Federal Council commissioned its Department of the Environment, Transport, Energy and Communications (DETEC), which houses the SFOE, to conduct a phase out cost study, modelling three scenarios to ensure the security of Swiss electricity supply in a nuclear phase out: premature replacement of the oldest plants, no replacement at end of their operating lives, and premature exit (Swiss Parliament, 2011). The Federal Council is ultimately in favour of the second scenario, rejecting considerations to alter the existing regulatory regime and determine decommissioning dates (Swiss Parliament, 2011). DETEC, alongside Prognos, found that total costs for not building new nuclear power plants would amount to an additional USD 31 billion by 2050, but a transition might be feasible assuming a 50-year operation, largely relying on increased gas-fired combined cycle power plants and imports (Swiss Federal Council, 2012).

Box 1.3. Switzerland's nuclear power plant safety and operating standards

Immediately following the Fukushima Daiichi accident, ENSI instigated an emergency equipment store, and Swiss nuclear power plants were backfitted with additional water supply connections to spent fuel pools (ENSI, 2021a). The conclusion of a three-year long investigation by ENSI found, post investments and updates after 2011, that Swiss nuclear power plants have a high level of protection against natural disasters and extreme weather conditions (ENSI, 2021a). Through active participation in EU stress tests, Swiss nuclear power plants were found to have a high safety level (ENSI, 2021b). The safety of Swiss nuclear power plants is reviewed comprehensively at least every ten years as part of a periodic safety review, with benchmarks for Generation III designs and legal requirements to perform safety retrofits (ENSI, 2021b). The safety standards of Swiss nuclear power plants rank among the highest in the world (Axpo, 2022b). Testament to its safety regime, Switzerland's first nuclear power plant, Beznau, the oldest active commercial nuclear power plant in the world, has provided low-carbon energy for over 50 years (Axpo, 2022a). Due to extensive maintenance and modernisation investments (over USD 2.5 billion), Beznau meets all regulatory and safety requirements, with approval from ENSI validating sufficient safety margins, for 60 years of safe operation (Axpo, 2022a).

In the United States, two-thirds of the 104 nuclear power plants have obtained long-term operation (LTO) extensions from 40 to 60 years, with a fifth of all reactors planning, and 6 obtaining, extensions from 60 to 80 years (DOE, 2020; NRC, 2022). Over USD 825 million have been invested in the past ten years in the Gösgen plant – with requirements for all nuclear power plants to be protected from a recently assessed 10 000-year flood (Delaye, 2022). A Swiss nuclear power plant LTO beyond 60 years may also be feasible as peaks in electricity demand for Swiss electricity generation have relied on flexible hydropower storage instead of altering nuclear power plant production capacities – which can wear down reactors more quickly over time (Delaye, 2022). Future safety standard requirements set by the ENSI will also factor into the economic and technical feasibility of long-term operation (LTO) of Swiss nuclear power plants. Nonetheless, Switzerland's significant investments in nuclear power plant upgrading post-Fukushima Daiichi, its high degree of nuclear power plant safety, and reliance on flexible hydropower storage appear to support operation beyond 60 years.

In 2011 the original CO_2 Act underwent a revision, entering into force in 2013, aiming at reductions of 20% of 1990 levels by 2020 (Swiss Federal Council, 2022a). In 2011 the National Council also voted to endorse a gradual phase out of nuclear energy by banning new construction licences, with the last unit projected to go offline by 2034 – assuming a 50-year operational duration for Leibstadt and Gösgen (WNA, 2022). The proposal was approved by the Council of States, subject to an ongoing review of technology which might allow for new nuclear power plants (WNA, 2022). Parliament was also in favour of a gradual phase out of nuclear energy, but voted against banning it altogether. Instead, Parliament mandated that Switzerland continue researching all energy sources, including nuclear energy, as spelled out in the ES2050 (IEA, 2018). In 2013, a proposition of the Federal Council on the legal text of the ES2050 was reached, focusing on reducing energy and electricity consumption, increasing renewable energies, ensuring access to international energy markets, converting and expanding the electric grid and intensifying energy research (Swiss Federal Council, 2013). In the same dispatch, the Federal Council adopted an official stance against a popular initiative introduced to limit nuclear power plant operating lives to 45 years, citing extended operating lives would allow more time to convert Switzerland's energy system and cushion costs associated with a rapid exit which would lead to higher imports and potentially undermine energy security (Swiss Federal Council, 2013).

Box 1.4. **Referenda and Swiss preferences: Beyond black or white**

Under the country's direct democracy, Swiss citizens have direct influence over political affairs, including energy policy. A referendum is required for any change to Switzerland's constitution or international treaties, while it is optional for legislation passed by parliament. Some 50 000 signatures within a defined time frame can initiate a referendum for legislation passed in parliament, and 100 000 signatures can create a popular initiative demanding a constitutional amendment (IEA, 2018). Referenda have featured centre stage in Swiss energy policy in general, and particularly in policy regarding nuclear power generation. The result of a referendum is binding, and not only advisory. Despite a majority voting in favour of the new Energy Act in which the construction of new nuclear power plants is prohibited, citizens appear aware of nuclear energy's contribution to security of supply, low-carbon energy production, and its low costs (Swissnuclear, 2017). Recognition of its practical advantages can be said to be reflected in rejections of a quicker transition away from nuclear energy by the electorate (Stadelmann-Stefen and Dermont, 2021). As an overview of Swiss energy policy up to the ES2050 demonstrates, in the fluid, even if slow-moving, context of Swiss consensus-based policymaking, definite stances on energy policy are not easily prescribed.

The most recent poll conducted in 2022 by the Demoscope Institute, on behalf of the Swiss Nuclear Forum, found that 44% of respondents believe Switzerland must continue to use nuclear energy to produce electricity, while 43% do not want to continue using nuclear energy (Nuklearforum Schweiz, 2022). The poll was conducted before rising energy costs or the war in Ukraine. At a European level, the 2022 Eurobarometer poll found that 90% of Europeans agree measures should be taken to limit the impact of rising energy prices, and 86% believe rising energy prices have a significant impact on their purchasing power (Eurobarometer, 2022). It is likely that rising energy costs and the real or perceived threats to the security of electricity supply in the wake of the new geopolitical situation following the war in Ukraine will continue to influence public opinion regarding nuclear energy in Switzerland.

The enduringly "split" opinion on the future of Swiss nuclear power may also be rooted in Swiss interest and desire for energy independence, often expressed as electric autarchy (Trutnevyte, 2014). This is reflected in a survey conducted at the University of Bern in 2016, finding that the technology option with the most widespread rejection by respondents for achieving net zero goals was electricity imports – signalling an enduring preference for energy sovereignty (Stadelmann-Steffen and Dermont, 2016). Arguments for Swiss energy sovereignty also featured strongly in the debate around political campaigns for the 2050 Energy Strategy (Rieder and Strotz, 2018). Nonetheless, debate exists on whether nuclear power can be fully considered domestic given needs for fuel imports, pending implementation of technologies capable of repurposing spent fuel.

In 2014, considering the proposed Energy Strategy 2050, the National Council called for nuclear power plant operators to submit plans for improving the safety of reactors operating beyond 40 years. The Council of States voted on the matter in 2015, agreeing to avoid placing legal limits on operating lives, or require operators to submit long-term operating concepts every ten years after 40 years of operation (WNA, 2022). The Council of States, given canton's reliance on Swiss hydropower levies, also voted to partially divert funds supporting renewables to further subsidise Swiss hydropower stations facing fiscal challenges (WNA, 2022). In 2016 the Energy Committee of the National Council voted against imposing limits on nuclear power plant operating lives and requiring ten-year operational assessments (Swiss Parliament, 2016). Rationale centred on acceptance of current safety requirements surrounding decommissioning and the potential for nuclear power plant operators to claim damages due to premature decommissioning (Swiss Parliament, 2016). The 27 November 2016 popular initiative proposing a 45-year limit on the operation of nuclear power plants failed, with voters expressing confidence in operators and ENSI (WNA, 2022). In May 2017 the referendum on the finalised ES2050, new Energy Act, including the original ban on new nuclear power plants as well as other measures was approved by a 58% majority, resulting in no construction licences for new nuclear power reactors (Federal Chancellery, 2022). Existing nuclear power plants are planned to be decommissioned at the end of their operation, and not to be replaced by new nuclear power plants (SFOE, 2018). However, no limits were placed on their operation if deemed safe by ENSI.

On 1 January 2018, the new Energy Act entered into force (SFOE, 2020c). The act defined non-binding targets for energy and electricity consumption up to 2035, including increased promotion of renewables, enhanced the legal right for smart metering, energy efficiency targets for private vehicles assimilated to EU limits with temporary subsidies for low CO_2 emitting vehicles and a ban on new nuclear power plants (SFOE, 2020c). Non-binding guidelines target 4 400 GWh of renewable energy by 2020, and 11 400 GWh by 2035, primarily supported by feed-in-tariffs financed by a network surcharge of 2.3 cents USD/kWh (SFOE, 2018). Large-scale hydropower plants also receive a market premium (compensation) for the difference between uncompetitive production costs and lower market prices, financed through a network surcharge of 0.2 cents/kWh (SFOE, 2018). Additionally, only hydropower facilities with an output > 1 MW can participate in the feed-in remuneration, with exceptions for facilities with low environmental impacts – partially limiting small-scale hydropower expansion (SFOE, 2018). The act also stipulates a ban on reprocessing of spent nuclear fuel, but not developing new nuclear technology (IEA, 2018).

1.4. Swiss energy policy in a net zero context

Switzerland became the first country to formally submit its contribution for a new climate agreement in Paris at the end of 2015, eventually to be ratified as the Paris Agreement in 2017 – aiming to limit average global warming to 1.5 degrees Celsius and halve greenhouse gas emissions by 2030 compared to 1990 levels (FOEN, 2018). Regarding adaptation to climate change, Switzerland is well positioned to fulfil the Paris Agreement – already having implemented most of the requirements under the initial 2015 draft, pending a full revision of the CO_2 Act (FOEN, 2018). In 2019, after taking into consideration the 2018 IPCC report stating that net emission balances of zero are needed to be achieved sooner, the Federal Council decided that Switzerland would increase its target for emission reductions to be achieved by 2050 (Swiss Federal Council, 2019). Beyond the federal government, coalitions of Swiss citizens also realise the significance of achieving net zero emissions. Citizens introduced the "Glacier Initiative" popular initiative in 2019, aiming to ban use of fossil fuels from 2050 and set interim goals at a legislative level to define emission reduction pathways (FOEN, 2021b).

To help inform the drafting of a long-term climate strategy, a requirement under the Paris Agreement, the SFOE commissioned the Energy Perspectives 2050+ (EP2050+) in 2020 from consultants TEP, INFRAS, Ecoplan and Prognos (Prognos et al., 2021). Central to the EP2050+, part policy guide and part economic study, are net zero scenarios modelled for Switzerland's energy system with the dual goal of net zero greenhouse gas emissions by 2050 and secure energy supply (Prognos et al., 2021). The report includes a basic net zero scenario focusing on increased energy efficiency and electrification, heating networks in urban areas, hydrogen and synthetic fuels, CCS, and negative emission technologies (NETs) (Prognos et al., 2021). Three additional net zero scenarios modelled focus on more electrification, increased hydrogen use, and less electrification

(Prognos et al., 2021). Two nuclear LTOs are modelled, 50 and 60 years – however, only costs for the 50-year scenario are published (Prognos et al., 2021). Significantly, the Prognos model does not employ cost optimisation in its scenarios (see Chapter 2). The report finds that net zero by 2050 is possible with the use of CCS and NETs to offset residual emissions from agriculture, incineration, waste, and industrial processes, with energy efficiency playing a key role in all scenarios (Prognos et al., 2021). Imports from neighbouring European countries are estimated to cover annual electricity requirements up to 2050, increasing after the decommissioning of nuclear power plants (Prognos et al., 2021). The report finds that the expansion of renewable energies under current frameworks is well behind levels required to cover domestic consumption by 2050, recommending expansion of renewables must occur on a scale that "clearly exceeds the current level" (Prognos et al., 2021).

Hydroelectric power plants are found to make a significant contribution, assuming expansion of flexible hydroelectric power plants and decentralised battery storage (Prognos et al., 2021). The yet-to-be-developed generation option of hydrogen-powered gas turbines in net zero scenario variants with high rates of technological progress appear to increase security, however, are not found to substantially lower imports (Prognos et al., 2021). Given an assumed high level of PV expansion and hydropower generation, domestic power supply is characterised by Switzerland remaining a net-importer in winter months (Prognos et al., 2021). Considering overall costs, the basis net zero scenario is projected to require investments of over USD 112 billion across 30 years (Prognos et al., 2021).

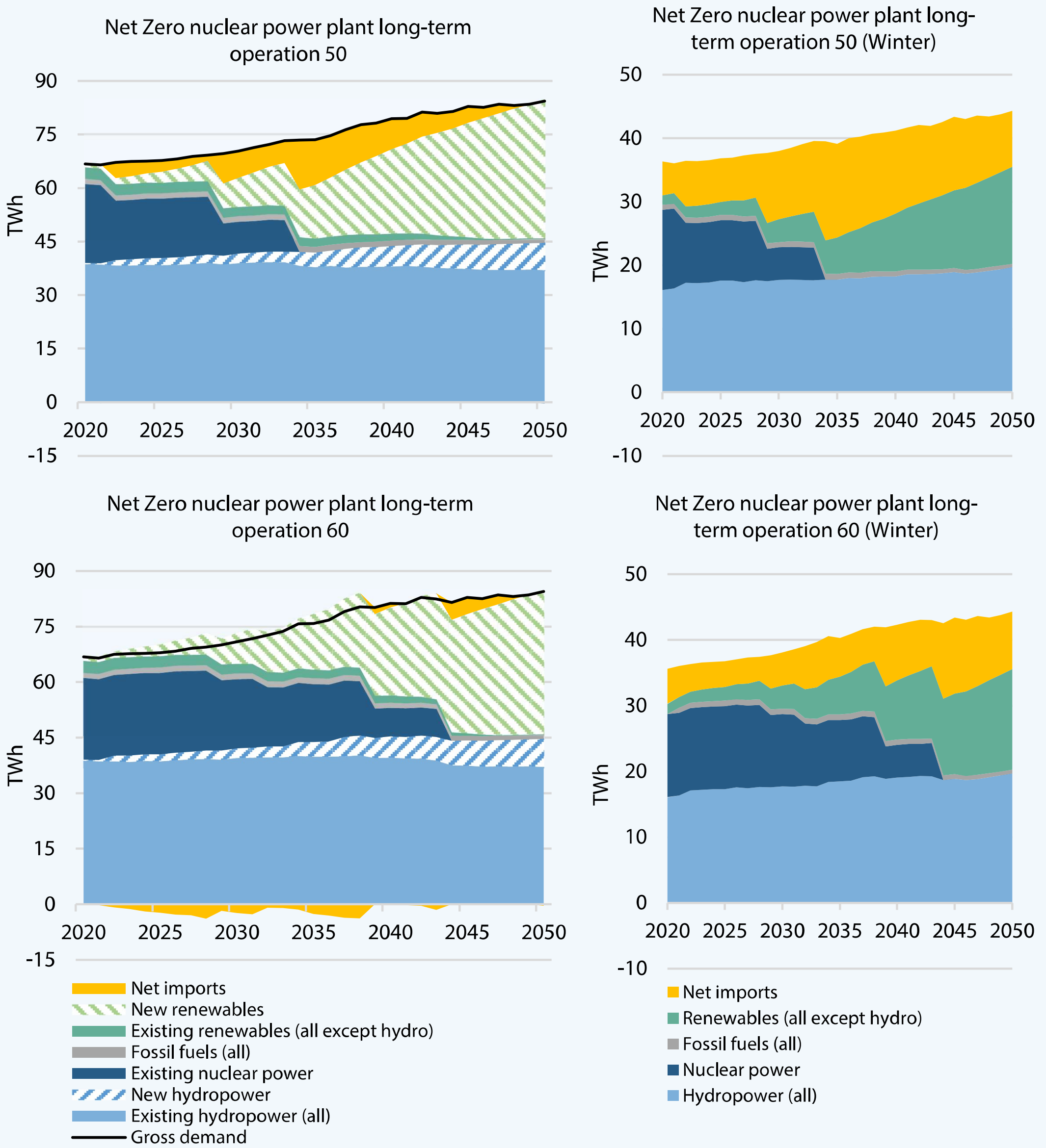
To ensure Switzerland met requirements stipulated in the Paris Agreement, in 2019 the Federal Council relied on the DETEC to draw up a Long-Term Climate Strategy (FOEN, 2021b) which was published in January 2021. The Long-Term Climate Strategy relies on the complete revision of the CO_2 Act voted by the Parliament in September 2020. Chiefly, the revision of the CO_2 Act aimed to increased domestic emission targets to at least 50% of 1990 levels by 2030 and to net zero by 2050, raise the CO_2 levy to USD 216 per tonne, introduce a new air ticket levy, set up a climate fund for financing climate protection measures, and extend the levy on fossil-based heating fuels for all sectors of the economy – creating emissions trading (Gesley, 2021).

Box 1.5. **Shifts in assumptions about the duration of nuclear power plant operations**

Two different operating periods for Swiss nuclear power plants have been chiefly considered in official reports (50 and 60 years). An operating period of 50 years, with the last nuclear power plant, Leibstadt, going offline in 2034 thus appeared the favoured federal stance after the Fukushima Daiichi accident. For example, Switzerland's Long-Term Climate Strategy only considers a 50-year nuclear power plant scenario (FOEN, 2021b). However, Switzerland's 2050+ Energy Perspectives report, which features a 50-year scenario, and a 60-year scenario with Leibstadt's decommissioning in 2044, finds "fundamentally lower electricity imports" in the 60-year scenario (Prognos et al., 2021). The difference ranges from an estimated "5 to 15 TWh lower in the years 2025 to 2040" (see Figure 1.2 below; Prognos et al., 2021). While the EP2050+ does not publish system costs for its 60-year scenario, the report also outlines that while renewables and fossil fuel generation contribution do not change across the two operation scenarios, the 60-year scenario leads to decreased energy prices (Prognos et al., 2021).

Shortly after the Swiss federal government terminated negotiations with the EU on an electricity agreement, in July 2021, at a lecture organised by the Association of Swiss Electricity Companies, the Vice President of Switzerland's Federal Energy Office, in a departure from the assumed 50-year scenario, stated that if nuclear power plants could be operated safely for 60 years, they would ease electricity supply (Meier, 2021). Although a decision to extend the duration of operation of nuclear power plants lifetimes lies within the domain of plant operators under the supervision of ENSI, the Swiss federal government held exchanges with nuclear power plant operators to better understand their plans regarding decommissioning and operational duration periods in early 2020 (Kraev, 2021; Thaler and Hoffman, 2022). The background for these exchanges may lie in concerns about security of supply if Switzerland cannot access future European electricity markets (Thaler and Hoffman, 2022).

Figure 1.2. **Electricity generation by technology, net zero basis with 50- and 60-year nuclear power plant scenarios (TWh) (Excerpt: winter seasonal generation)**



Source: Prognos et al. (2021).

At a public event in June 2021, a large Swiss utility listed keeping existing nuclear power plants connected to the grid for 60 years as a strategy for the utility to ease security of supply during winter months (Meier, 2021). In Axpo's 2021 annual report, the utility states that having invested several hundred million dollars in the Beznau, Leibstadt and Gösgen nuclear power plants, "enabling them to run for at least 60 years… allow(ing) sufficient time to expand the renewable energies required to achieve a successful energy transition" (Axpo, 2021). Another large Swiss utility also stated aiming for an operational period of at least 60 years (Delaye, 2022). In 2020, yearly reports from Gösgen's and Leibstadt's operators, present values of financial costs for the plants are accrued and compounded over expected service lives of 60 years – reflecting confidence in (at least) 60 years of operation (Kernkraftwerk Gösgen, 2021; Kernkraftwerk Leibstadt, 2021). The Swiss energy law in place in 2022 allows for extensions to nuclear power plant operation as there is no specified limit for long-term operation of existing nuclear power plants if their operation is deemed safe by ENSI.

Switzerland's Federal Electricity Commission (ElCom), chiefly responsible for monitoring the system adequacy of Switzerland's electricity generation, has historically assessed system adequacy using an assumed 50-year operation scenario. However, one of the latest system adequacy studies commissioned by ElCom and Swissgrid in June of 2020 with a time horizon of 2030, ruling out the conclusion of an electricity agreement (modelling bilateral technical contracts reducing energy-related border capacity), assumes an operational duration of 60 years for Swiss nuclear power plants (ElCom, 2020c). According to ElCom, system adequacy can be guaranteed by the market in this extended operating scenario, however, in the worst case, there may be instances where energy may not be able to be supplied during winter months (ElCom 2020c). Based on ElCom's findings, even with a 60-year nuclear power plant operational periode scenario, problems are most likely to arise in the winter, particularly if the two largest Swiss nuclear power plants (Gösgen and Leibstadt) are not available (SFOE, 2021b). ElCom recommends a legally binding expansion target of at least 5 to 10 TWh for generation capacities in the winter by 2035 (ElCom, 2020c).

Switzerland's Long-Term Climate Strategy covers all sectors in the greenhouse gas inventory; however, it does not determine specific domestic or international shares for reducing emissions (FOEN, 2021b). The strategy stresses that a 2050 net zero target requires the use of carbon capture and storage and NETs (FOEN, 2021b). The potential for binding 2035 and 2050 targets for renewable and hydropower generation are also included (FOEN, 2021b). Switzerland's Long-Term Climate Strategy foresees its building sector to no longer generate emissions by 2050, chiefly through carbon-free heat-pumps and heating networks, biomass-based heating systems, district heating, and energy efficiency (FOEN, 2021b). Swiss industrial emissions are expected to be reduced by 90% compared to 1990 levels, mainly through greater electrification, substitution of fossil fuels, increased energy efficiency, and NETs to offset hard-to-decarbonise industries (FOEN, 2021b). Swiss transport emissions are also viewed to be no longer generating emissions by 2050 even though the transportation sector had failed to meet the interim target of 1990 levels by 2015 (FOEN, 2021b). Achieving net zero in this sector hinges on increased electrification of cars, primarily battery powered vehicles (FOEN, 2021b). The aviation sector is projected to be no longer generating climate-impacting emissions by 2050; however, although emissions from international aviation in Switzerland are increasingly significant (around 11% of total emissions), they are not included in the CO_2 Act, and therefore no currently agreed-upon plan exists to reduce emissions (FOEN, 2021b). Food and agricultural sector emissions are foreseen to be cut by at least 40% compared to 1990 levels through ecological performance requirements, direct payments, and border controls (FOEN, 2021b). Finally, for Swiss sectors such as its waste sector, and hard-to-decarbonise industries, the strategy reiterates the necessity for CCS and NET, and given limited domestic potential, mentions that Switzerland is likely to rely on negative emissions abroad (FOEN, 2021b).

While Switzerland's Long-Term Climate Strategy was adopted in January 2021, the proposed revised CO_2 Act, voted by the Parliament in September 2020 after several years of debate, was rejected by referendum in June 2021 (FOEN, 2021a). In the complex system of Swiss energy decision-making, this failure to pass, primarily due to negative public opinions towards carbon taxes on air travel, may slow efforts, but does not imply abandonment of federal net zero emission targets for 2050. Rather, alongside current ES2050 policy challenges explored in the following section, it implies a renewed need to consider several pathways to fulfilling carbon emission targets.

1.5. Current developments in ES2050 implementation

Following the failure to pass the revised CO_2 Act, after 2022 the CO_2 tax would no longer have been increased to USD 125 per tonne, companies would no longer have been able to claim CO_2 tax exemptions and Switzerland would no longer have a national emission reduction target, even though it remained bound by an international target of 50% of 1990 levels by 2030 due to the Paris Agreement (FOEN, 2021a). For this reason, in April 2022 the Federal Council revised an ordinance to the CO_2 Act, thereby avoiding a regulatory vacuum until 2025. The ordinance kept intact undisputed elements of the existing CO_2 Act (Swiss Federal Council, 2022a). Therefore, between 2022 and 2024, Switzerland must reduce its emissions by 1.5% per year compared to 1990 levels (Swiss Federal Council, 2022b).

In June 2022, the Federal Council approved a counterproposal of the energy commission of the National Council to the yet-to-be-voted “Glacier Initiative” popular initiative seeking to ban fossil fuels, emit no greenhouse gases that cannot be offset by CCS, and achieve net zero carbon emissions by 2050 (with technical exceptions). Recognising that the initiative might be too ambitious, the Federal Council supports such measures like a net zero emissions target by 2050, a negative net emission target after 2050, and the definition of national intermediate targets – while avoiding banning the use of fossil fuels. These measures will be part of the revision of the CO_2 Act under preparation in 2022 that aims at avoiding some of the controversies of the June 2021 referendum (Swiss Federal Council, 2022c).

With an end to formal discussions with the EU regarding an electricity agreement in 2021, given rising concerns surrounding security of electricity supply, DETEC commissioned reports assessing security of supply in the short and medium term from ElCom, Swissgrid, and Frontier Economics. Based on these reports, which outline that in the worst-case scenario security of supply may not be achieved in the winter, the Federal Council invited ElCom to draw up plans for gas power plants to cover peak loads (Swiss Federal Council, 2021a). ElCom recommends 2-3 plants for 1 000 MW for an estimated USD 928 million (Swissinfo, 2022a). However, geopolitical developments from the war in Ukraine concerning natural gas imports may limit the feasibility of building new gas power plants in the short term.

Box 1.6. **The JASM study: Values from different scenarios**

As the debate about Swiss energy policy in the context of net zero carbon emissions is ongoing, there is sustained demand for analysis of diverse long-term policy scenarios. One of the most authoritative efforts in this context was provided in 2021, when modelling teams from the eight Swiss Competence Centers for Energy Research (SCCER) collaborated in Joint Activity Scenarios and Modelling (JASM) to analyse varying configurations of the energy system for possible pathways towards net zero goals (Panos et al., 2021). The study included a base net zero scenario (CLI) implementing emission standards for building and vehicles while assuming improved Swiss-EU trading schemes (Panos et al., 2021). Beyond the base scenario, net zero variants included assuming fragmented international climate policy, slow technical progress, weak energy market integration, and low use of renewables (ANTI), assuming the former while fully exploiting potential for domestic renewables (SECUR), building on (SECUR) while increasing Swiss integration to international markets (MARKETS), and a variant building on the former while projecting globally co-ordinated R&D in low-carbon technologies (INNOV) (Panos et al., 2021). For all variants, the JASM study assumes a 60-year LTO for all nuclear power plants apart from the Mühleberg plant. The study finds that without CCS, net zero ambitions cannot be achieved in Switzerland. The study also finds that installed capacity of solar PV must double every decade from now until 2050, and a majority of private cars will need to be electric by 2050 (Panos et al., 2021).

The study concludes that under favourable conditions, achieving net zero will cost USD 100 billion over 30 years (undiscounted), and under fragmented national and international policies, low market integration, low exploitation of renewables, and slow technical progress, up to USD 440 billion (which corresponds to an overall cost of 10% to 60% of the 2020 Swiss GDP over 30 years) . The JASM study, which is a key reference for the present report (see also Chapters 2 and 3), confirms a central insight: energy policy choices and their framework conditions matter for determining overall costs to Swiss society for achieving net zero by 2050. The study also included a system adequacy assessment of its base net zero scenario, finding it is equipped to ensure security of electricity supply only until 2040. Beyond this point, grid constraints might cause loss of load, especially in the net zero scenarios (Panos et al., 2021).

To revise the Energy Act and Electricity Supply Act in order to better address security of supply and net zero objectives, in 2021 the Federal Council also proposed a Federal Law on a Secure Power Supply with Renewable Energies (Swiss Federal Council, 2021b). The law foresees an expansion of 2 TWh of climate-neutral generation for securing winter electricity supply, principally by expanding large storage hydroelectric power plants to establish a strategic energy reserve (Swiss Federal Council, 2021b). Other measures include extending support strategies for renewables until 2035 by replacing feed-in-tariffs with investment contributions and extending network surcharge durations (Swiss Federal Council, 2021b). Additionally, the law stipulates binding target values or renewables in 2035 and 2050. The target value for 2035 for the expansion of renewables (excluding hydropower) is 17 000 GWh, significantly higher than the previous 11 400 GWh (Swiss Federal Council, 2021b). As subsidies for renewables are set to expire in 2023 and 2030, the SFOE states in its message on the act that there is "immediate risk that construction will decrease or even collapse" (Swiss Federal Council, 2021a). The message states that if the expansion target of 2 TWh cannot be achieved by 2040 with large-scale hydropower, tenders should be invoked open to all technologies with shorter lead times, including gas-fired combined cycle power plants – with net zero targets being maintained through additional CCS or NET (Swiss Federal Council, 2021b).

Box 1.7. **Challenges faced by Swiss technology options**

Achieving the target of net zero carbon emissions by 2050, at reasonable costs, requires a well-balanced low-carbon generation mix. Almost all technology options have supporters, and often, vocal detractors. A 2022 study surveying 364 energy-related organisations in Switzerland found no consensus over the feasibility of ES2050 policy goals, with a majority of respondents even perceiving the goals as unrealistic (Duygan et al., 2022). A brief overview of the principal challenges facing each option in the Swiss context follows below.

Nuclear power: Axpo and Alpiq have highlighted their diversified portfolio in shareholder communications, noting positive performance outside Switzerland has helped offset financial losses due to market prices below production costs for domestic nuclear and hydropower operations on the domestic market (IEA, 2018). Policy uncertainties affect operational and decommissioning plans for Switzerland's nuclear fleet, as well as the ability to attract a qualified workforce to safely manage plants (IEA, 2018). As ElCom reported, in 2016 and 2017 availability of nuclear power plants decreased compared to the ten-year average, particularly due to a lengthy winter outage (ElCom, 2020d). As nuclear power plants age, probability of unforeseen shutdowns (for technical and economic reasons) increases (ElCom, 2020d). Clear policy signals will be necessary to allow nuclear operators to plan long-term operations (LTO) given investments and lead times required to refurbish nuclear power plants or receive approvals from ENSI (IEA, 2018). Present renewable electricity generation capacity is viewed as insufficient to compensate for the gradual decommissioning of nuclear power plants (Thaler and Hoffman, 2022). Additional renewable capacity may not be brought online in time to fully replace the phasing out of nuclear plants (IEA, 2018). If Swiss nuclear power plants are phased out as originally planned (50-year duration of operation) and expansion of renewables continues at the current pace, Swiss energy security stands to be further reduced (Schneider and Vallet, 2019; Thaler and Hoffman, 2022).

Hydropower: Swiss hydropower faces an unresolved hurdle – modernising its traditional "water tax" system. Today, water charges bring around USD 568 million into the coffers of cantons and communes where hydroelectric power plants are located (Tibère and Guerrero, 2017). The National Council approved a revised Water Law Act maintaining the maximum water rate where it stands until 2024 (SFOE, 2022). A proposed water rate consisting of a fixed and fluctuating part (depending on market prices) may be agreed upon in the future. Expansion of Swiss hydropower will also be constrained by the Regulation on Water Protection, as pumped storage power plants will have to let more unused water pass through them (Titz, 2020). The volume of several reservoirs is likely set to decline in the coming years (Tattersall and Rohr, 2019). Balancing utilisation of hydropower with protection of waters is a relevant factor limiting extension of hydropower (Grünewald et al., 2021).

A study by the Swiss Federal Office of Energy (SFOE) indicates that prime costs for hydropower electricity production were higher than revenues power producers earned – In 2016 the sector lacked USD 319 million (Axpo, 2018). Traditional large-scale hydropower projects continue to have high production costs, so that most projects are not economical without financial support (Swiss Federal Council, 2021b). For smaller plants, extensive renewal investments are often "not economically viable" (Swiss Federal Council, 2021b). While potential to expand hydropower exists, it is currently exploited at 95% (Schneider and Vallet, 2019; Grünewald et al., 2021; Panos and Kannan, 2018). Handling of large-scale hydropower in the new energy law also involved conflicts between developers and environmentalists (Stadelmann-Stefen and Dermont, 2018; Diaz Redondo, 2018). Additionally, electricity from hydropower has been significantly volatile across years and seasons, explaining energy security reasons that historically led to development of alternative electricity sources such as nuclear (Schneider and Vallet, 2019).

Variable renewable energy: For solar farms and wind turbines there exists strong objection against building units in unaltered nature, where tourism is a major source of income (Grünewald et al., 2021). Public opposition to PV and wind have emerged at the local level (Krummenacher, 2016). Opposition has stopped some projects, potentially obstructing and delaying implementation of the energy strategy (Diaz Redondo, 2018). Expansion of wind power in Switzerland has been slower than PV as wind is not particularly strong or consistent in most of Switzerland, and residents opposed to wind turbines have relied on spatial planning laws at the cantonal and communal level to halt projects (Van Vliet, 2019; Panos and Kannan, 2018). Numerous wind energy projects in Switzerland are currently blocked by local objections (Stadelmann-Stefen and Dermont, 2021).

Natural gas and CCS: Relaxing sustainability criteria by producing electricity from new temporary domestic gas power plants will also likely result in higher energy costs (Thaler and Hoffman, 2022). Resorting to gas-fired power plants has proven controversial in Switzerland, facing opposition from environmental groups (SES, 2020; WWF, 2014) on the one hand and open calls for no longer decarbonising electricity supply on the other (Laübli and Häne, 2020). Recent geopolitical events and the European gas shortage in 2022, however, have weakened calls for new gas-fired capacity. In addition, CCS is associated with uncertainties in costs and geological storage, facing issues related to public perception and the absence of legal frameworks (Sutter et al., 2013). Not only is storing captured CO_2 in Switzerland viewed as a challenge, but studies show that the required storage potential is not available in Switzerland, requiring foreign CCS (Panos et al., 2021). For the present study CCS is not modelled (see also Chapter 3).

Geothermal and biomass: The potential for expanding geothermal energy appears limited, mainly due to local opposition (Thaler et al., 2019). Geothermal energy remains a somewhat controversial issue in Switzerland due to induced seismic activity from drilling related to two exploratory geothermal projects (Stauffacher et al., 2015). However, several exploratory geothermal projects are underway. Finally, biomass mainly faces challenges regarding logistics and costs (Panos and Kannan, 2018).

Beyond long-term decarbonisation targets, shorter-term developments are also leaving their mark on energy policy. In May 2022, the Federal Council presented to Parliament a message on a rescue mechanism law for up to over USD 10 billion in loans providing temporary liquidity to important Swiss electricity companies until 2026 (Swiss Federal Council, 2022d). While Swiss electricity companies are overall considered to be in a stable position, this preventive instrument would allow companies to fill liquidity gaps in the case of further extraordinary electricity price increases, such as those that have been experienced in 2022 due to the war in Ukraine (Swiss Federal Council, 2022d). Discussions about an exceptional hydropower reserve between the federal government and the stakeholders of the energy market were ongoing in 2022 in order to secure an additional electricity production capacity in case of energy shortage during the 2022/2023 winter. The government could proceed through ordinance in the framework of the Electricity Supply Act to have this mechanism ready for the 2022 winter, but aimed to implement it as part of the Federal Law on a Secure Power Supply with Renewable Energies (Swissinfo, 2022b).

Swiss energy policy is in an evolving state. Nevertheless, increasing concerns about the balance security of supply and costs, while achieving net zero carbon emissions, are rising to the forefront. Expansion of technology options to fulfil net zero goals are being pursued in a multifaceted policy environment, including a legally binding nuclear phase out, with open shutdown dates, electricity market integration and developing geopolitical challenges. In a complex and shifting environment, Swiss energy policy has often adapted to – and indeed was borne out of – uncertainties facing Switzerland's energy future. Nuclear power and hydropower have since constituted the backbone of Swiss electricity supply, also creating a sizeable low-carbon generation advantage for realising net zero carbon emissions, possibly the most significant and ambitious energy policy challenge of this century. While current legal frameworks prohibit the expansion of nuclear power, the possibility for existing Swiss nuclear power to help secure electricity supply and contribute to fulfilling net zero emissions appears to begin to be recognised in current debates. Understanding the prospects and costs of net zero pathways with all available technologies, including nuclear energy, may help better inform Swiss energy policy at its current crossroad, where it faces demands for decarbonisation while also assuring electricity supply for the winters to come. In this context, the present report aims to provide a carefully elaborated and analytical contribution to the ongoing debate over Switzerland's future energy policy and net zero emissions pathways.

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Chapter 2: NEA system cost modelling and Swiss system cost models

2.1. Introduction

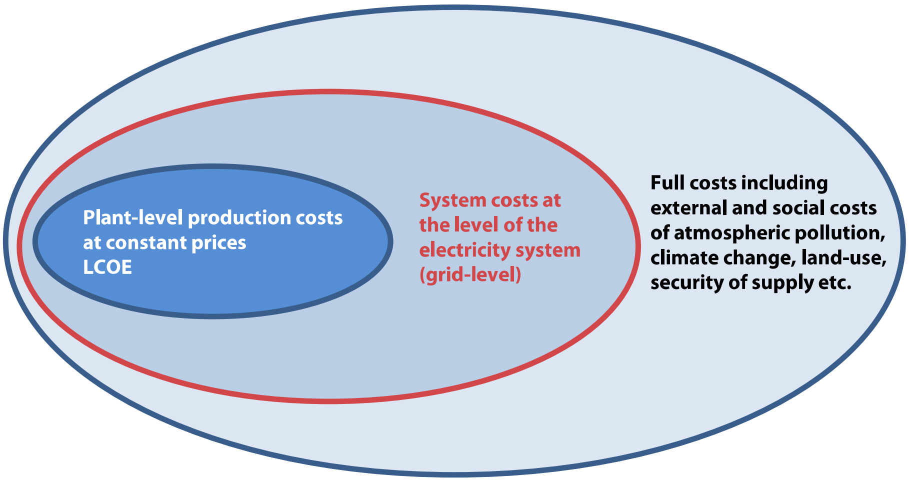
Accounting for the costs of distinct generation mixes in pathways towards ambitious net zero carbon emission objectives is indispensable for informed decision-making in the field of energy and electricity policy. The present report contributes to this effort, assessing the costs of five scenarios with distinct generation mixes capable of attaining net zero carbon emissions in the Swiss electricity and energy sectors. Following the exploration of current Swiss energy policy debates, this chapter provides an overview of cost accounting and its methodologies in the electricity sector before concentrating on contemporary Nuclear Energy Agency (NEA) work in the areas of levelised cost of electricity (LCOE) accounting and system cost modelling. The second half of the chapter will situate this work in the context of the broader literature on the costs of the Swiss electricity system. This will provide a useful background for both the specific characteristics and the results of the present study presented in Chapters 3 and 4.

There exists an ample and growing literature on cost accounting in the electricity sector. Studies consider regional and national differences, focus on different technologies, and employ different methodologies. Cost accounting in the electricity sector can be further complicated by the fact that electricity is often considered, at least partially, a public good, or as a commodity that has significant impacts on other public goods such as the environment and a secure energy supply. Therefore, policy priorities matter in the optimisation of energy and electricity systems, impacting modelling choices explicitly and implicitly. Electricity system modelling evolved significantly in response to the advent of extensive deployment of variable renewable energy (VRE) technologies such as onshore and offshore wind and solar PV. Throughout this report the term VRE is employed to further differentiate intermittent renewable technologies (solar PV and wind) from more stable renewable technologies such as hydropower, which are particularly relevant in the Swiss context. VRE deployment impacts total system costs through two channels: first, the direct costs of VRE capacity and; second, the indirect costs induced by its intermittency that requires sizeable amounts of dispatchable capacity to be available at all times but generating only during a reduced number of hours. The intermittency, variability and, to some extent, unpredictability of VRE poses not only technical and economic challenges for dispatchable competitors, but also for system operators. Finally, increased penetration of VREs challenge established tools of electricity market experts and modellers.

Figure 2.1 offers three simple categories to comprehend and relate the principal cost categories in electricity system modelling. The most basic element of electricity system modelling is the LCOE. Introduced in the regulated electricity systems of the 1960s, this methodology provided a relatively simple and intuitive tool to compare the lifetime costs of different baseload generation technologies – typically coal, gas and nuclear energy. By discounting or compounding all lifetime costs for capital, operations, and fuel consumption to the date of commissioning and dividing their sum by the total discounted lifetime revenues, regulators disposed of a handy gauge for the costs of each technology per unit of output, typically one MWh of electricity. To guarantee comparability, usually identical load factors and discount rates were employed across technologies – not barring use of varying rates and factors.

The LCOE methodology was initially challenged by the advent of electricity market liberalisation in the 1980s and 1990s. Different market functions, risk profiles and business models questioned the comparability that had existed for baseload power suppliers in a regulated environment. Despite this the methodology survived because it continued to provide a simple reference and starting point for more complex, but ultimately non-generalisable findings, and it conveyed the viewpoint of a policymaker or social planner – unlike private entrepreneurs aiming at individual profit maximisation. Therefore, policymakers, regulators, and experts remained interested in having a baseline understanding of comparative resource costs for technology options before considering market conditions, price dynamics and financial risks for further analysis.

Figure 2.1. **Major cost categories in electricity systems**



Source: Adapted from NEA, 2019.

However, the advent of VREs, such as wind and solar PV, fundamentally questioned the use of LCOE. All technologies impose some external costs on the electricity system that are not accounted for in LCOE calculations. Nuclear energy and coal, for instance, have specific siting requirements due to cooling needs or require special grid characteristics for outlay and capacity of transmission lines. While these added costs at the level of the grid-based system were relatively small compared to the overall costs of either generation or transport and distribution, the variability of wind and solar PV introduced effects to a different magnitude. With their increasing penetration, it was no longer sufficient to take the plant-level LCOE of different technologies as indicators of their total system costs. Variability of renewables introduces a differentiation in a technology's service. Roughly, one can distinguish between variable technologies producing during a limited window determined by weather and time, technologies producing around-the-clock predictably, and flexible technologies coming into play when output from variable technologies is unavailable.

The variability of wind and solar PV forces planners to adopt a system perspective. No matter the degree of solar PV capacity installed, some dispatchable capacity is required to supply electricity at night, which inevitably increases overall system costs to meet a given demand pattern. In the language of system cost analysis this is referred to as profile costs, or also as utilisation or back-up costs. To profile costs, by far the largest component of electricity system costs, there must also be added balancing costs, arising from uncertainty rather than variability of electricity generation, grid costs in the form of added outlays for transport and distribution, which can be significant for decentralised renewables, and connection costs. A key reason why LCOE must be complemented by other forms of analysis is therefore constituted by the introduction of variable production. Adding profile costs to technology-specific LCOE plant-level costs is not a sufficient approach, as the former are a function of the interactions at a system level. For example, in an electricity system with high shares of flexible hydroelectric resources, the system costs of variable renewables will be lower than in systems with only coal and nuclear energy. This is not only a question of the technical ability to load follow, but of the economic characteristics of the technologies complementing VREs. To keep unit costs low, technologies with high fixed costs require high load factors. However, in systems with large amounts of wind and solar PV, operators are unlikely to obtain such high operating hours, which drives up system costs.

Beyond dependency on systems, the value of accounting for electricity costs exclusively on a basis of LCOE has been further diminished by the advent of new technologies such as storage or flexibility options such as demand response and hydrogen production. For storage, net output (release minus charging) is zero and yet it provides a valuable service with real costs that can only be related to the LCOE with additional assumptions (see D'haeseleer and Delarue in IEA/NEA, 2020). In short, LCOE accounting on its own is no longer effective in integrated low-carbon systems with significant shares of variable renewables.

However, LCOE analysis also remains an important input for alternative approaches. In the past ten years, methodological advances, and technological progress in computing power and modelling software have allowed mixed-integer linear programming (MILP) models to emerge as a tool for analysing the costs of integrated electricity systems. Since decentralised profit optimisation will lead to results identical to those of centralised cost minimisation, these models are equally applicable in systems with perfect competitive electricity markets and regulated systems. As they minimise the combined costs of investment and dispatch to satisfy a given demand pattern, typically with an hourly resolution over one year, all the information contained in traditional LCOE analysis, including an appropriate discount rate, is also included in these models. However, their innovation is that they not only construct, subject to the exogenous constraints defined by policy, an optimal generation mix, but they also provide hour by hour optimised least-cost dispatch. In other words, the system interactions between variable technologies, dispatchable baseload providers and flexibility providers, including storage, demand response and hydrogen production are fully included. In such an analysis, results will indicate the total system costs of specific choices, rather than technology-specific costs transferable from one constellation to another. The structure and workings of the NEA's POSY MILP model that has been used to analyse the different net zero scenarios in the Swiss context are described in further detail in Chapter 3.

Finally, the external or social costs that affect the utility of individuals and societies beyond goods and services that can be fully priced out can only be very imperfectly monetised or modelled, even though the costs of carbon emissions, air pollution, biodiversity, land use or a lack of security of electricity supply are by now well recognised. While one could claim that they are not accounted for at all in system cost models, this is only partially true. Although MILP models do not provide explicit cost numbers for specific public goods, they *implicitly* reflect the costs of the policy choices to safeguard them by way of constraints imposed on the model. For instance, a net zero carbon objective by 2050 for Switzerland will clearly appear in the total system costs of the Swiss electricity system. An electricity system with a carbon constraint will necessarily be more expensive than an electricity system without one.

System cost analysis of integrated low-carbon electricity systems is therefore one of the most exciting advances in energy economics in recent years, and an effective tool for understanding costs associated with distinct energy policies in terms of carbon emission constraints, desired technology generation shares, or demand patterns. Naturally, the diligence, innovation, and resource inputs of various modelling teams impact overall model results. Beyond this outline of the contribution of system cost modelling, the remainder of this chapter offers insight from modelling results with the greatest pertinence to an assessment of the system cost of net zero electricity in Switzerland.

2.2. Plant-level cost accounting: The projected costs of generating electricity series

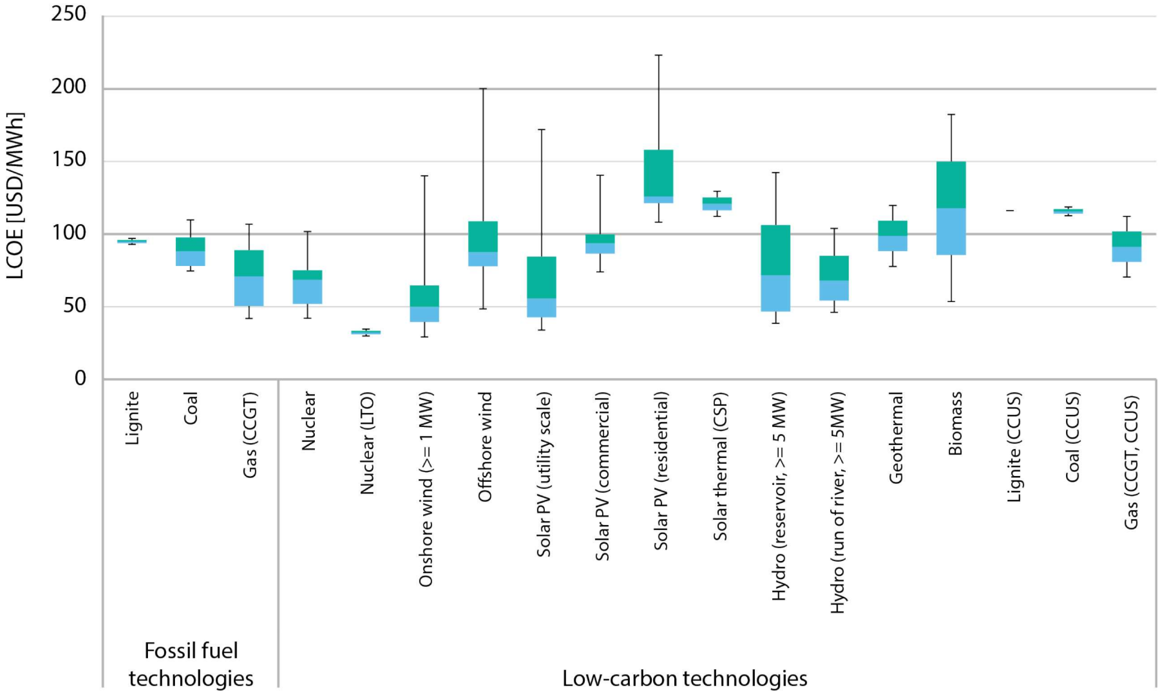
The international adoption of the LCOE methodology in the assessment of the costs of different electricity generating options was strongly supported by a series of reference studies first pioneered by the NEA and then continued jointly by the NEA and the International Energy Agency (IEA/NEA) as *Projected Costs of Generating Electricity*. The first edition in 1981 established the reference framework and methodology for the calculation of levelised costs. The report used a 5% discount rate and compared only two energy sources: nuclear energy and coal, broadly finding nuclear energy cheaper than coal-generated electricity (information on editions up to 2010 is based on the historical synthesis in IEA/NEA, 2015). The second edition published in 1984 additionally included a 10% discount rate, coming to similar conclusions as the first. The third edition in 1989 concluded that while nuclear energy maintained a significant cost advantage over coal, projected decreases in coal prices could lead to coal-powered electricity gaining an advantage in some countries. The fourth edition in 1992 included natural gas-fired plants as well as some renewables in main analyses, reflecting their increased importance following the twin developments of electricity market liberalisation and rising concerns about climate change due to the emissions of greenhouse gases, in particular carbon dioxide. The 1992 report, however, found no clear winner among nuclear energy, natural gas and coal technologies, in particular because of decreased projected fossil fuel prices, with variable renewable technologies uneconomic in most cases.

The fifth edition in 1998 and the sixth edition in 2005 also found no clear winner among the three dominant baseload technologies, with renewable energy technologies remaining generally uncompetitive. The 2005 edition however mentioned that increased liberalisation of energy markets contributed to uncertainty, favouring less capital-intensive and more flexible technology options. This edition was the first to include a quantitative analysis of hydropower, extending the lifetime capacity factor to 85% for coal, natural gas and nuclear power plants (IEA/NEA, 2015). The seventh edition in 2010 for the first time included a carbon price and the LCOE figures for gas- and coal-based generation to reflect policy objectives of reducing greenhouse gas emissions. In general, the report found that the variability and unpredictability of many renewable technologies still placed them at a relative disadvantage compared to more stable sources. The report once again concluded that there is no one technology with a clear advantage on the global or even regional level.

The eighth edition in 2015 examined LCOE for all main electricity generating technologies. Including a greater variety of technologies and 22 countries, the report reaffirmed drivers of the cost of generating technologies remain both market and technology-specific. Costs of low-carbon technologies were found to depend significantly on the cost of capital, while coal and natural gas-fired generation fuel costs and the price of CO_2 emissions. Significant decline in the cost of renewable generation was reported due to improved technologies and government support. The report also found that nuclear energy costs remain in line with the costs of other baseload technologies. No technology was found to be the cheapest. The ninth edition published in 2020, drew on data from 24 countries, also included information on the costs of storage technologies, long-term operation of nuclear power plants and fuel cells. It also found that the levelised costs of electricity generation of renewable low-carbon generation technologies, nuclear, hydroelectricity and renewables, were falling increasingly below costs of conventional fossil fuel generation. The cost of electricity from new nuclear power plants was found to remain stable, yet electricity from the long-term operation (LTO) of nuclear power plants constituted the least-cost option for low-carbon generation. Coal-fired power generation was reported to be slipping out of a competitive range (IEA/NEA, 2020).

From a context where the LCOE of baseload technologies were relatively similar and renewables uncompetitive, current nuclear power maintains its cost advantage compared to coal and natural gas, when the costs of carbon emissions are integrated, and the LCOE of renewables are nearly at competitive levels to fossil fuel generation. Results still depend heavily on the discount rate. This is also confirmed in other studies such as RTE (2022). The lower the discount rate, the greater the cost competitiveness of capital-intensive low-carbon technologies such as nuclear energy, hydroelectricity, solar PV or wind. This raises questions about the market designs necessary to accomplish the low-carbon energy transitions, a question currently hotly debated in several countries and beyond the scope of this report.

Figure 2.2. **LCOE ranges for electricity generation technologies (7% discount rate)**



Note: light and dark blue rectangles indicate value ranges for the second and third quartiles of data points provided.

Source: IEA/NEA (2020).

2.3. **System cost modelling to examine low-carbon scenario costs**

In a system cost approach, the different components of system costs (profile costs, balancing costs, grid costs and connection costs) are added, or subtracted if negative, to the pure cost of generation, which is often expressed by the LCOE. By comparing the system LCOE of two or more technologies, it is possible to rank them in terms of overall economic efficiency and determine which one brings more benefits to a system. The definition of system costs inherently implies the comparison of two distinct electricity systems in equilibrium, their calculation requiring a defined generation mix that can serve as a benchmark for comparison. In simple systems, comparing the system costs of only two technologies allows direct comparisons of the system costs of different technologies. In more complex systems, system costs cannot be allocated so easily, but more advanced analysis can still provide insights into the contribution of different technologies to the costs of the overall system.

System effects are often divided into the following broadly defined categories, with the fourth category (connection costs) sometimes considered separately:

- profile costs (also referred to as utilisation costs or back-up costs);
- balancing costs;
- grid costs;
- connection costs.

Profile costs: refer to the increase in cost of the electricity system in response to variability of VRE output. They capture the fact that in most cases it is more expensive to provide residual load in a system with VRE than in an equivalent system where VRE is replaced by dispatchable plants. Indeed, additional back-up generation or storage capacities are necessary to compensate the volatility of the VRE production. Profile costs can also be viewed as the opportunity cost of not having, in the long term, a cheaper conventional generation mix for a system's residual load. The presence of VRE generation generally increases the variability of the residual load, resulting in steeper and more frequent ramps. This can cause additional burden to other dispatchable plants – more start-ups/shutdowns, more frequent cycling, and steeper ramping requirements. Conventional generation plants thus operate with lower efficiency and increasing wear and tear of equipment, which leads to higher generation and system costs. This effect is also known as the flexibility effect (Hirth et al., 2015b). Costs associated with the curtailment of VRE during hours where their supply exceeds demand and threatens system stability are also accounted for under profile costs. Finally, profile costs include the system effects of VRE's low-capacity credit, or the fact that generally VRE contribute less to satisfying peak demand compared to dispatchable plants.

Balancing costs are related to increased requirements for ensuring system stability with the help of operating reserves due to uncertainty in power generation (unforeseen plant outages or generation forecasting errors). Balancing takes the form of cycling, which means a dispatachable plant operates at less than full capacity, so that it can ramp up quickly in case of need. In the case of dispatchable plants, the amount and cost of operating reserves are generally given by the contingency in terms of the largest unit (or two largest units) connected to the grid. In the case of VRE, balancing costs are related to the uncertainty of their output due to short-term changes in the weather. Typically, any non-scheduled behaviour due to forecasting errors is included as balancing costs (excluding pre-announced ramping up or down, a scheduled behaviour). There exist differences across studies with respect to accounted elements and methodologies employed to measure balancing costs. Some studies include the cost of holding balancing reserves, the definition of "short-term" varies across studies, and some studies use current market prices for imbalances while others rely on modelling data (NEA, 2019). Cycling is costly because plants are operated at less than economically optimal capacity but also due to increased wear and tear of frequent ramps, in this case due to unforeseen events rather than to predicted weather patterns. Despite being a dispatchable technology with predictable output, some balancing costs must also be attributed to nuclear energy. These costs, below USD 1 per MWh_{VRE}[1], are explained by the fact that nuclear power plants often constitute the installations with the largest capacity in an electricity system and thus define the amount of operating reserves according to the N-1 citerion (NEA, 2019).[2] System configurations matter for balancing costs. They thus lie in a range of USD 2 to 6.1 per MWh_{VRE} for wind power in thermal systems, while costs for solar PV and wind power in more flexibile hydro-based systems can be much lower, sometimes less than USD 1 per MWh_{VRE} (NEA, 2019).

Grid costs reflect effects on the transmission and distribution grid due to the location of generation plants. While all generation plants may have some siting restrictions, impacts tend to be more significant for VRE. Given such locational constraints, new interconnections may need to be built or the capacity of existing transmission infrastructure (grid reinforcement) increased to carry generated electricity to consumers. Transmission losses tend to increase when electricity must be moved across sizeable distances. Also, high penetration levels of distributed PV resources may require sizeable investments in the distribution network to cope with more frequent reverse power flows occurring when local demand is insufficient to consume electricity generated. Quantitative estimates available on grid costs are characterised by large variations, reflecting the characteristics of individual systems, different penetration levels of VREs analysed, whether distribution costs have been included, and specific methodological assumptions. However, available estimates lie in a broad range from a few USD per MWh_{VRE} up to USD 25-30 per MWh_{VRE} (NEA, 2019).

Connection costs represent the cost of connecting a power plant to the nearest connection point of an existing power grid, and are only seldom considered in system cost studies, as these costs are often borne by the plant developer and thus integrated into plant-level costs. However, connection costs can be paid by the transmission operator and therefore become a part of system costs. Connection costs are not integrated in the LCOE methodology developed by the

1. Reported values on system costs (or on each of its components, profile, balancing, grid and connection costs) are expressed in USD per MWh of VRE generated. To avoid confusion, they are indicated as USD/MWh_{VRE} throughout the report.
2. Reported values on system costs (or on each of its components, profile, balancing, grid and connection costs) are expressed in USD per MWh of VRE generated. To avoid confusion, they are indicated as USD/MWh_{VRE} throughout the report.

NEA and IEA. Estimates of an NEA study, averaged over different countries, are of the order of USD 0.5 per MWh for gas power, USD 1 per MWh for coal, USD 2 per MWh for nuclear energy, USD 6 per MWh_{VRE} for onshore wind, USD 14 per MWh_{VRE} for solar PV and about USD 20 per MWh_{VRE} for offshore wind (NEA, 2019).

There are other system effects, however, they are economically less important. For instance, the absence of the heavy rotating mass of thermal power plants with large steam turbines in VRE dominated systems can lead to a lack of inertia, which makes it more difficult to maintain stable frequencies on transmission and distribution networks. Creating synthetic inertia is possible – albeit at a cost.

Although studies on the economic dimension of system effects are relatively new, a sufficiently rich literature is building up on the topic. However, given the complexity of such analysis, most studies focus on only one or two components of system costs. Complete and comprehensive analyses of system effects are less common. Among studies that cover a broad spectrum of system costs can be underlined the work at the OECD by the IEA and NEA (OECD, 2015; IEA, 2011 and 2014; NEA, 2012), the wind and solar PV integration study undertaken by Agora Energiewende (2015), a study at the European level by the French utility EDF (Vera and Burtin, 2015), a study on the future power system in Belgium by the University of Leuven (Delarue et al., 2016), several studies published by Lion Hirth and Falko Ueckerdt (Hirth, 2013, 2015a, 2015b, 2015c, 2015d, 2016a and 2016b; Ueckerdt et al., 2013a and 2013b) and at Imperial College London (Strbac et al., 2015 and 2016).

Most studies focus on system costs associated with the introduction of VRE, and only minimal attention has been given to those associated with dispatchable technologies (NEA, 2019). One of the few early studies on this aspect was undertaken by the NEA (2012), in which the system costs of different conventional power plants were compared with those of VRE, explained in further detail in Section 2.2.

A survey of the literature shows a wide range of model results, which underlines challenges in comparing system cost studies. It should be kept in mind that quantitative results are influenced by many factors and assumptions, which may significantly differ among studies (NEA, 2019), such as:

- different power systems are assessed, with different shares of flexible hydropower plants;
- different levels of VRE penetration;
- different assumptions on the development, availability and cost of technologies in the future: in particular assumptions on available storage technologies, smart grids and demand response deployment;
- cost assessments are made in a long-term or on a short-term perspective, with different assumptions on the ability of the power system to adapt;
- different definitions for each system cost component;
- distinct models with a different degree of complexity and predictive capacity;
- different policy frameworks for the analysis.

Impact of increased VRE production on profile costs, on the value of electricity sold at market price and more generally on system costs

At least since the first NEA system cost study in 2012, there has been a concerted effort to understand, capture and quantify the impacts that the introduction of VRE has on residual load, the generation mix, and security of supply. In the long term, the deployment of VRE induces a significant change in the structure of conventional generation mixes, requiring a greater overall capacity as well as a shift from baseload technologies to peakers – energy sources, usually gas turbines, that can be turned on and off quite rapidly – and mid-load capacity. As discussed below, in the long run, the shares of capital-intensive baseload generators will thus be reduced and replaced by peak and mid-merit plants which increases overall system costs (NEA, 2019). In most cases, a system with VRE exhibits increased costs for providing residual load compared to a system without VRE, with costs increasing exponentially with the penetration level of VRE. While there is broad consensus that VRE introduce fundamental structural changes in electricity systems, the quantification of profile costs requires significant modelling efforts. Furthermore, model results remain sensitive to many parameters, assumptions, and the quality of computational tools used.

Profile costs are closely related to the declining value of electricity from VRE generation based as their penetration increases (NEA, 2019). The literature offers limited estimates of profile costs, but all suggest that they are sizeable, especially at high VRE penetration levels: the NEA and IEA provide similar estimates for wind power; values lie in a range of USD 4 to 10 per MWh_{VRE} at 10% and 30% penetration levels (IEA, 2014; NEA, 2012). The results for solar PV show a wider range, possibly reflecting analysis of different systems: for two penetration levels of 10% and 30%, IEA estimates are in the range of USD 4 to 15 per MWh_{VRE}, while NEA results lie in a range of USD 13 to 26 per MWh_{VRE}. Overall, a broad survey of about 30 studies of profile costs estimates long-term profile costs to lie between USD 15.4 and 25.6 per MWh_{VRE}, for wind at a 30% penetration level (Hirth, 2013). The USD 10 per MWh_{VRE} identified for a combined share of 30% wind and solar PV combined of NEA (2019) actually come in at a slightly lower range but rise quickly reaching almost USD 35 at 75% penetration.

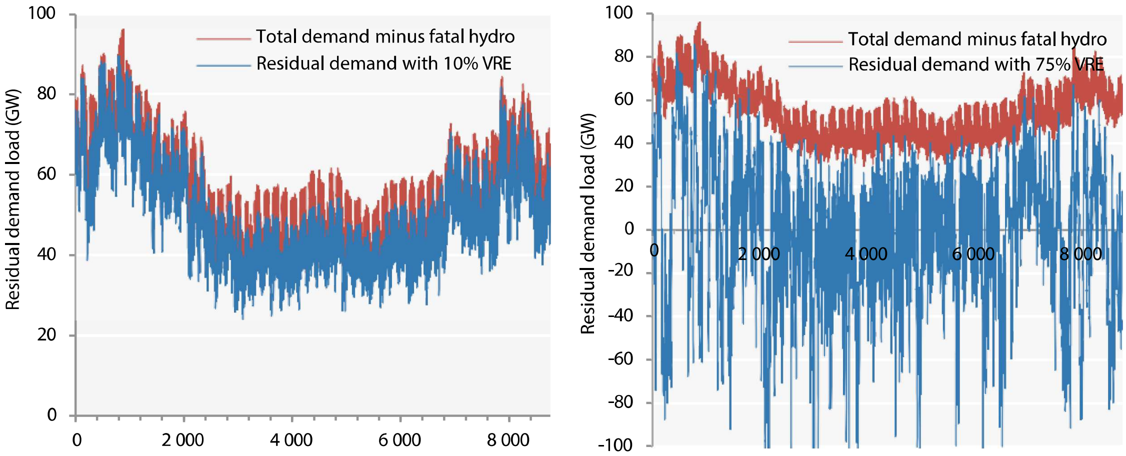
Given that a VRE generator is likely to produce when other VRE generators are also producing, explicitly reducing the value of electricity sold, the market value of VRE decreases with the scale of VRE deployment. All studies surveyed in Hirth (2013) show that the market value of VRE decreases significantly with higher penetration levels and more markedly for solar PV than for wind power. Value factor loss appears less pronounced for more flexible electricity systems with large hydro resources (Hirth, 2016a). Due to production profiles concentrated during a few hours with high load, the value factor for solar PV decreases far more quickly than for wind, reaching about 60% of baseload costs at a 15% penetration level (Hirth, 2015c).

Additional parameters impacting system costs – Adequacy and capacity

The adequacy of an electricity system is measured by its ability to continually satisfy future demand, considering the fluctuations of demand and supply, reasonably expected outages, and projected construction and retirement of generating capacity (NEA, 2019). To remain within acceptable economic limits, most power systems operate with a targeted level of reliability – an acceptable probability that some amount of load will not be served during certain periods. With respect to generation capacity, all power systems, therefore, maintain a total amount of capacity exceeding the expected maximal level of demand by a given fraction, or reserve margin. Among dispatchable technologies, nuclear energy is the most sensitive to reduced capacity factor due to increasing VRE generation. At a 7% discount rate, decreasing the capacity factor from 85% to 30% is found to increase the LCOE for nuclear by 147% (IEA/NEA, 2015). That is why questions of market design and system layout are particularly important for the economics of nuclear power.

With respect to generation plants, the concept of capacity credit is often used to measure the relative amount of load that can be reliably ensured by a power plant. The capacity credit of a power plant is defined as the additional load that can be served following the deployment of an additional unit of a specific generation technology to the system while maintaining the same level of reliability (Keane et al., 2011). Compared to dispatchable technologies, the capacity credit of VRE and its ratio to the load factor varies across a wider spectrum, reflecting the distinct contribution to the system adequacy and services it can provide to the system (NEA, 2019). However, generally low-capacity credit of VRE decreases further as its share in the mix rises as its production patterns are uncorrelated with system needs and demand. However, to the extent that dispatchable capacity is displaced, moments of VRE overproduction requiring to be curtailed in the absence of widespread availability of low-cost storage opportunities will alternate with moments of stress that will need to be covered by remaining dispatchable capacity or demand response (NEA, 2019, see also Figure 2.3). Because additional VRE generation is correlated with existing VRE output (auto-correlation effect), adding more VRE to the system will do little to increase output during these hours. Precisely because of their variability, VREs have a significantly lower capacity credit than dispatchable technologies, especially at high penetration levels. Therefore, VRE tends to have a much lower contribution to system adequacy than dispatchable plants as only a fraction of its potential output is likely to be available during peak demand. Other resources or technologies are needed to compensate for VRE's lower contribution to system adequacy, which is at the heart of increasing profile and overall system costs.

Figure 2.3. **Residual demand loads for electricity systems with 10% and 75% VRE penetration**



Source: NEA, 2019.

Storage and flexibility options

There is little disagreement that flexibility is an essential element to manage the variability of solar PV and wind resources, and that sizeable investments in flexible resources are needed to integrate a significant share of VRE in the generation mix (NEA, 2019). Imperial College London research indicates that "the system integration costs of low-carbon technologies will significantly depend on the level of system flexibility" and that "…very significant costs savings can be made by increasing the flexibility of the electric power sector" (Strbac et al., 2015 and 2016). According to their technical abilities and cost profiles, different technologies will naturally be employed to answer different flexibility needs. Broadly, five technological options are identified as potential sources of flexibility and system services (NEA, 2019):

- **Flexibility from conventional power plants**: Conventional generation currently provides the majority of flexibility and system services in all OECD countries.
- **Network development and cross-border or interstate interconnections:** The creation of a larger electricity system can lead to less correlated demand and generation infeed from renewables, contributing to a flatter and less variable residual load.
- **Electric energy storage technologies:** Pumped hydroelectric storage and chemical batteries are employed to shift energy demand from peak to off-peak periods, levelling the residual load. In addition to existing technologies, compressed-air energy storage and fuel cells potentially offer additional options.
- **Demand-side response (DSR):** DSR is the capacity of users to voluntarily lower or shift their consumption in response to changes in the state of the electricity system.
- **Operational flexibility from VRE:** This category includes renewable energy generation that can be curtailed, that is disconnected from the grid during periods of excess production.

To these five categories, a sixth one can be added: scarcity pricing during rolling blackouts operated by the network operator when system stability is endangered due to a demand and supply mismatch. This is equivalent to involuntary and unscheduled demand response with considerable welfare costs for residential and industrial consumers. Nevertheless, such cost are, of course, lower than those of a complete system breakdown.

A comprehensive study of the system costs of VRE in the United Kingdom by the Imperial College of London outlines that availability of flexibility in the system in terms of new storage capacity, additional interconnections or demand-side response, is a key parameter in system costs (Strbac and Aunedi, 2016). Overall system costs vary widely across technologies: for onshore wind they vary between USD 9.7 and 54 per MWh_{VRE} compared to USD 10.1 per MWh_{VRE} in the study's reference case, for offshore wind between USD 7.5 and 65 per MWh_{VRE} compared to USD 10.5 per MWh_{VRE}, and for solar PV between USD 11 and 59 per MWh_{VRE} compared to USD 19 per MWh_{VRE} in the reference case (NEA, 2019).

Carbon emission constraints and system costs

In electrical power systems, given the need to deploy new low-carbon technologies to comply with net zero emission targets in the 2050 horizon, imposing new or stricter carbon emission targets will inevitably increase the costs of providing electricity to customers due to both replacements of existing technologies and implementation of new low-carbon technologies. Moreover, it is logical to expect that the marginal costs associated with decarbonisation are expected to increase over-proportionally with the degree of decarbonisation targeted, as the most cost-effective measures appropriate to each system are implemented first (such as wind power or coal replacement by natural gas), while increasingly stringent decarbonisation goals require the adoption of more costly and often more technically challenging measures (such as solar PV, batteries, or carbon capture and storage [CCS]) (NEA, 2019).

A Massachusetts Institute of Technology (MIT) study has analysed a range of possible decarbonisation scenarios in the United States as a function of different carbon emission targets and of a different set of available low-carbon power generation technologies available (Sepulveda, 2016; MIT, 2018). The study considered two power systems within the United States the Electric Reliability Council Of Texas (ERCOT) and the Independent System Operator New England (ISO-NE) regional markets, which have different characteristics in terms of load curves and heat demand, hydro resource availability, as well as VRE potentials and generation profiles. Different carbon constraints were imposed on each system: from a target of 400 g per tonne of CO_2 to 1 g per tonne of CO_2, with intermediate targets. Two different sets of technology pathways were considered: the first relying exclusively on renewable technologies (wind, solar and hydro resources) as well as battery storage, while the second also included nuclear power in the mix. In both pathways the generation mix was completed by fossil fuel plants, open-cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT) which are deployed to the extent allowed by the carbon constraint imposed. Under less ambitious decarbonisation targets the total system costs of electricity generation are similar in the two power systems. With more stringent carbon emissions generation costs increase almost linearly with nuclear power in the mix, while generation costs increase over-proportionally with only VRE. Differences in terms of costs between the two power systems are much smaller if nuclear power is added to the mix (MIT, 2018).

A second aspect underlined by the MIT study is the change in the structure of the optimal generation mix as the carbon intensity of the power system is progressively reduced. As the system is required to reduce its carbon intensity, fossil fuel generation is gradually replaced by low-carbon technologies. If only VRE are allowed, the capacity of VRE and storage increases over-proportionally with the carbon constraint. In both power systems, wind energy is deployed first and starts with a higher share, but is progressively replaced by solar PV as the system is further decarbonised. Imposing stricter emissions constraints changes the mix drastically, with nuclear energy displacing both gas and wind energy, while the capacity of solar remains approximately constant. In the study, nuclear power is found to be the most competitive low-carbon source providing most of the capacity in the system, whatever the targeted carbon intensity. Overall, the study concludes that the "...diversity of energy sources drives down total costs of energy in a low-carbon system, whereas taking options off the table – such as nuclear – creates extra costs" (MIT, 2018).

NEA 2012 – Nuclear Energy and Renewables

The NEA 2012 study, *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems*, was part of an early wave of studies analysing the system costs of power generation technologies. The study was the first systematic quantification of grid-level system costs for six NEA member countries (Finland, France, Germany, Korea, the United Kingdom and the United States). It also examined the financial impacts of introducing VRE on the profitability of dispatchable technology electricity generation. In the short run, with the current structure of the power generation mix remaining in place, the study found that the value for electricity produced from all dispatchable technologies, nuclear energy, coal and gas, as already explained suffered due to lower average electricity prices and reduced load factors. However, to its lower variable costs, the study also found that at a constant capacity mix for which fixed costs have already been sunk existing nuclear power plants fared relatively better than gas and coal plants. This effect is, however, outdone in the long run when new capital investment costs need to be accounted for, which causes high capital cost technologies such as nuclear to be comparatively more affected than coal or gas.

The study also found that if electricity generation is to be based increasingly on VRE, increasing storage capacity is needed in the system. While the study's 50% renewable scenario requires a total storage capacity of approximately 250 GWh, in the 80% renewable scenario the required annual storage capacity dramatically increases to 6 400 GWh, thus significantly increasing profile costs (NEA, 2012). With the assumed composition of renewables in the different scenarios, the sum of total installed capacity in the system increases significantly with rising shares of renewables, from approximately 110 GW for a 15% renewable share up to more than 340 GW for an 80% share (NEA, 2012). Furthermore, comparable amounts of conventional power plant capacity are required in all scenarios due to the low-capacity credit of variable renewables. With increasing penetration of VREs, the curtailment of variable power plants is also found to become significant. For instance, with a 35% and 50% share of renewables, the curtailment of electricity generation from wind and PV power plants is negligible, while annual curtailment of variable renewables rises to approximately 9% of possible annual generation in the 80% renewable scenarios. Overall, under the assumption of an identical carbon constraint, renewable energies are found to contribute to an increase in total system costs whereas nuclear power leads to a decrease in total system costs.

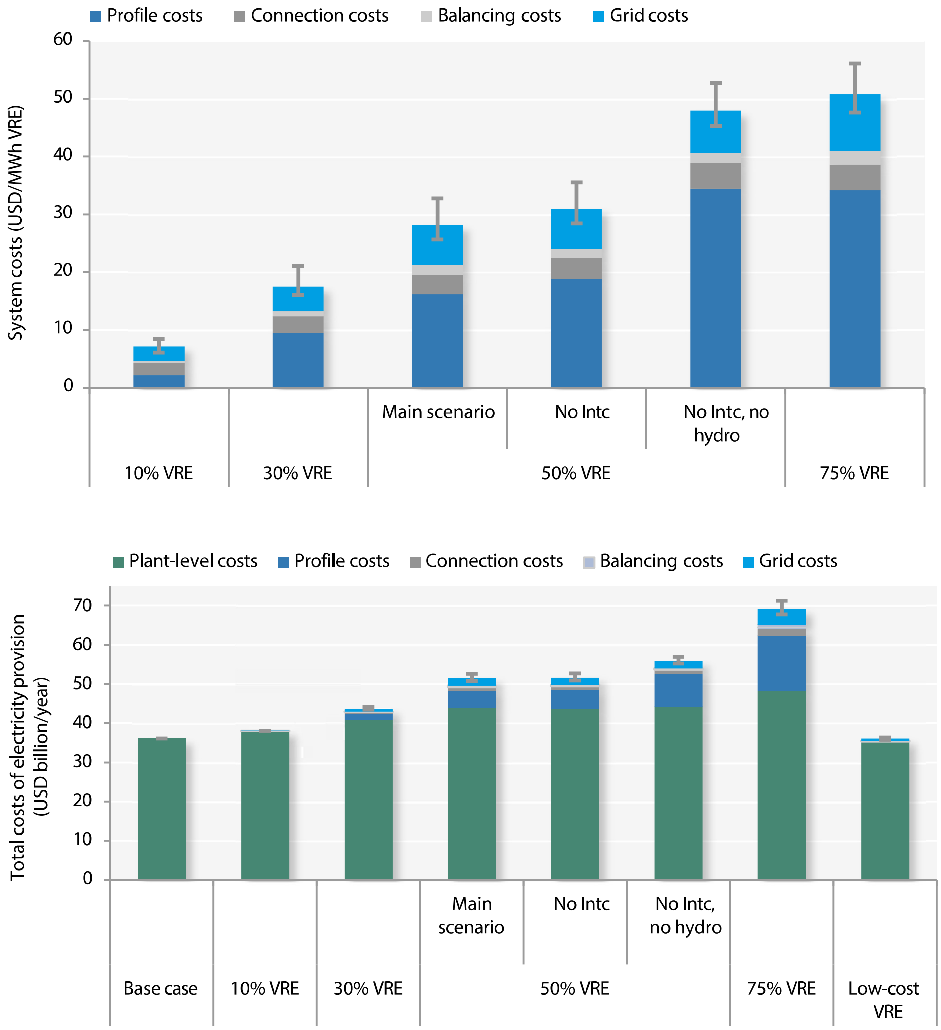
NEA 2019 – The Costs of Decarbonisation

If the NEA's 2012 study provided first insights into the relative system costs of different generations mixes, a more systematic approach to the phenomenon of system costs in electricity systems with high shares of VRE was undertaken by the NEA in 2019 and published as *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables* (NEA, 2019). Co-operating with MIT researchers, the study's authors constructed a detailed representation of the electricity sector including hourly dispatch, ramping constraints, and reserve requirements. In addition, a set of credible flexibility options were added to the model: interconnections with neighbouring countries, a relatively high share of flexible hydroelectric resources, demand-side management (DSM) as well as battery storage. The study concentrated on a single representative country, taking many features of the French electricity system including the annual load curve and VRE profiles, to develop different decarbonisation scenarios characterised by varying shares of nuclear energy and variable renewables. The analysis was based on a greenfield approach, where the system is optimised over the long term and costs are minimised without making any assumptions about the existing power generation mix, other than the availability of hydroelectric resources. The main scenarios in the study confront the cost of systems with exogenously defined shares of wind and solar PV of 10%, 30%, 50% and 75% with those of a system aiming at cost minimisation by means of a carbon constraint of 50 g/kWh (NEA, 2019).

The results were instructive. Under the study's carbon constraint scenario (and without CCS), coal is never deployed, and the share of fossil-fuelled generation remains almost constant in all scenarios. In terms of electricity generation, given the carbon constraint, the main phenomenon observed was that with more ambitious renewable energy targets, VRE generation replaces nuclear power almost on a one-to-one basis. As expected, total generation capacity increases markedly with VRE deployment: in comparison with the base case, the installed capacity more than doubles in the scenario with 50% VRE generation and triples in the 75% VRE scenario (NEA, 2019). This reflects not only the lower load factor achievable by VRE compared to dispatchable baseload plants, but also an increasing curtailment of VRE generation and their low-capacity credit. Achieving more ambitious renewable targets also implies that VREs are curtailed more frequently. Curtailment of VRE generation appears already at a 30% penetration level and increases sharply with their increasing share. A consistent reduction in the load factors of traditional baseload and mid-load plants is observed with increasing shares of VRE in the generation mix.

Under the cost assumptions of the study, the generation mix which meets the electricity demand at a minimal cost is found to rely on dispatchable low-carbon generation technologies, such as nuclear power and hydroelectric power. The cost of generating electricity increases with the share of VRE in the system. For a mid-sized country as the one represented in the study, additional costs for electricity generation are found to range from a few to over USD 15 billion per year (NEA, 2019). Consistent with the previous NEA study on system effects and the recent scientific literature, the study shows that total system costs are significant, and they increase more than proportionally with the deployment of variable resources. The level of system costs becomes substantial when the deployment of VRE reaches higher levels (see Figure 2.4): at 30% VRE penetration, total system costs more than double, up to USD 17.5 per MWh_{VRE}, and they reach USD 30 per MWh_{VRE} at 50% penetration (NEA, 2019).

Figure 2.4. **Estimated system costs in identical low-carbon systems (50 gCO_2/kWh) with varying shares of VRE and nuclear power (USD billion per year)**



Source: NEA, 2019.

It is essential, however, to understand that the VRE system costs depend strongly on the country-specific characteristics of the system considered. Systems with lower flexible resources face more severe challenges to integrate VRE resources and higher electricity generation costs. Additionally, assumptions concerning hydroelectricity and interconnections with neighbouring countries are crucial. Closely integrated countries with sufficient interconnection capacity (such as Western European countries) can absorb the variability of VRE more easily than more isolated countries (e.g. Japan or Korea). Countries with large dispatchable hydropower resources such as Switzerland are in a similarly favourable situation.

2.4. Energy system modelling in the Swiss context

Following the announcement of the 2050 energy strategy and Switzerland's intent to pursue a nuclear phase out in 2011, several studies began modelling Switzerland's future electricity generation mix and associated costs. Early waves of studies (2012 to 2015) placed emphasis on a nuclear phase out, without focusing on net zero emission constraints by 2050, with at most only a partial reduction (50-60%) of 1990 emission levels. An overview of past studies and generation mixes, largely omitting models imposing net zero constraints, can be found in Thimet and Matrovatidis (2022) and Xexakis et al. (2020). Both literature reviews do not yet include recent attempts to model Switzerland's energy mix under net zero carbon emissions such as Panos et al. (2021). Generally, in Thimet and Matrovatidis (2022) models with limited carbon emission reductions are found to replace nuclear power with natural gas, and for more ambitious carbon emission reductions with solar, electricity imports, bioenergy and natural gas combined with CCS.

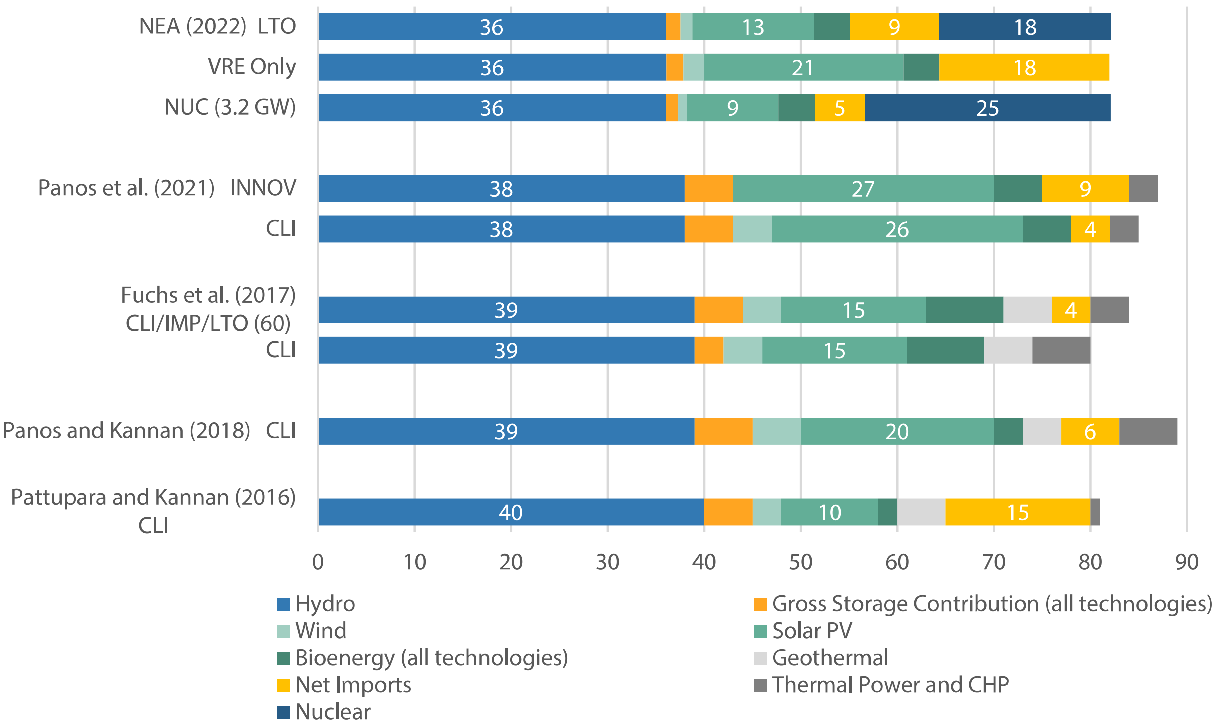
The assumptions and inputs concerning electricity prices, data resolution, and model sophistication in earlier studies are not easily comparable to more recent models with net zero carbon emission reduction restrictions. However, the only studies including nuclear power beyond 2050 in the generation mix are found in earlier models, with only partial carbon emission reduction restrictions. Weidemann et al. (2012), modelling a scenario with emission reductions of 60% from 1990 levels by 2050, found that achieving emission reductions with new nuclear power plants, assuming an inititial operating period of existing nuclear power plants of 50 years, resulted in additional costs of USD 15.7 billion compared to the baseline with unrestricted emissions. Conversely, achieving the same emission reductions without nuclear power resulted in additional costs of USD 208 billion compared to the baseline (Weidemann et al., 2012). The least-cost nature of an extension of nuclear power is equally supported in a recent study of the Swiss energy system excluding emission reduction restrictions, modelling nuclear builds following 60 years of operations of existing plants (Weiss et al., 2021), in Pattupara and Kannan (2016) modelling new nuclear builds without emission restrictions as the least-cost baseline and in Fuchs et. al (2017) modelling the difference between a 50- and 60-year LTO under net zero restrictions. However, no existing study imposes net zero emission restrictions for scenarios with nuclear power in the electricity generation mix beyond 2050.

Several recent studies, particularly after the passing of the new Energy Act in 2017, introduce 90% reduction in 1990 CO_2 levels, or 1-1.5 tCO_2 per capita, in line with the SFOE and 2050 energy strategy net zero targets. Of these studies, four model system costs and electricity generation in a context of cost optimisation. Studies including both near net zero emissions as well as net zero emission scenarios are summarised in Table 2.1. Most studies employ the Swiss TIMES Energy Model (STEM), a high resolution, technology-rich cost-optimisation model for the Swiss energy system developed by the Paul Scherrer Institute (PSI), see also Box 2.1. The EP2050+ report (Prognos et al., 2021), employs its own bottom-up energy model, but does not include cost optimisation. Considering studies with a net zero carbon constraint (the first five in Table 2.1), none include connection costs, balancing costs and grid costs. Only Fuchs et al., (2017) includes grid expansion costs. A majority of net zero studies model Switzerland as a singular region, without also modelling the electricity sectors of neighbouring countries. As the STEM model employs an hourly intra-annual time resolution of three typical days for four seasons, all net zero cost optimisation models offer similar sampled resolutions. Overall, models are found to exhibit similar total electricity generation (between 80 and 90 TWh), while varying in electricity generation technology shares, most visibly solar PV, net imports as well as thermal and combined heat and power (CHP), as shown in Figure 2.5.

Table 2.1. **Selected net zero and quasi net zero Swiss 2050 electricity generation models**

Studies	*Institutes*	*Emissions*	*Nuclear power plant LTO*	*Models*	*Cost optimisation*	*Modelled countries*
Panos et al. (2021)	SCCER, PSI, SFOE	1-1.5 t CO_2 or > 90% (1990 CO_2 Levels)	60	STEM, SES, ETHZ	✓	Switzerland
Fuchs et al. (2017)	PSI, FEN		50, 60	STEM	✓	Switzerland
Pattupara and Kannan (2016)	PSI		50	CROSSTEM	✓	Multiple
Prognos et al. (2021)	Prognos, SFOE		50, 60	Prognos, Ecoplan		Switzerland
Panos et al. (2018)	-		50	STEM	✓	Switzerland
Landis et al. (2019)	SCCER	Emission reduction through CO_2 taxes	50	CEPE, CITE, STEM, GEMINI-E3	✓	Switzerland
Maire et al. (2015)	PSI, Econability		50	CROSSTEM, GENESwIS	✓	Multiple
Babonneau et al. (2016)	-		60	STEM	✓	Switzerland
Weidmann et al. (2012)	-	60% (1990)	50, NUC+	MARKAL, STEM	✓	Switzerland
Kannan and Turton (2014)	-	60% (1990)	50	STEM	✓	Switzerland
Panos et al. (2019)	-	50% (1990)	50	STEM	✓	Switzerland

Figure 2.5. **Electricity generation mixes in cost-optimised net zero 2050 scenarios (TWh)**



Note: Scenarios include the present report and other selected studies.

In terms of costs, net zero scenarios that rely on higher shares of generation from VREs, and lower net imports, tend to exhibit higher overall system costs compared to model reference baselines, or business as usual (*Weiter wie bisher*) scenarios. Quite intuitively, scenarios including a higher deployment of VRE also exhibit higher shares of storage. In Fuchs et al. (2021) increasing nuclear power plant operation to 60 years coupled with net imports is found to represent the least-cost net zero scenario. An increase of nuclear power plant operation to 60 years alone is found to decrease undiscounted system costs by approximately USD 94 billion over 40 years compared to a 50-year scenario (Fuchs et al., 2021).

While recent studies arrive at similar conclusions regarding the amount of electricity generation required for increased electrification in Switzerland under a net zero carbon constraint for its energy sector, system costs, due to assumptions regarding imports and CCS, result in varying shares of VRE, storage, thermal power and CHP and net imports. Scenarios with higher generation shares from net imports are generally found to exhibit the lowest system costs. In line with results from past NEA modelling studies (NEA, 2019; 2012), a review of the literature on Swiss net zero system costs appears to confirm that long-term operation of existing nuclear power plants, limiting reliance on VRE, contributes to lower overall system costs. However, only Fuchs et al. (2017) explicitly explores the costs of a ten-year extension of the duration of operation of current nuclear power plants under net zero carbon emissions. While the EP2050+ (Prognos et al., 2021) explores the implications for the generation mix of 50- and 60-year nuclear power plant operations, it does not provide system costs for a 60-year LTO.

Box 2.1. **The Swiss TIMES Energy Model (STEM)**

The Swiss TIMES energy system model (STEM) is a bottom-up, technology-rich model of the Swiss energy system employed by several Swiss research institutes (Kannan and Turton, 2014). All selected cost-optimisation net zero studies mentioned in Figure 2.4 employ the STEM model. The Swiss energy system in STEM spans resource supply to energy service demands for more than 90 energy end uses. The model includes a suite of energy and emissions commodities, hundreds of technologies, and infrastructures for 17 energy demand subsectors (Panos et al., 2021). STEM identifies the least-cost combination of technologies and fuels to meet exogenous emission targets while also fulfilling imposed technical or policy constraints. STEM is a single-region model of Switzerland with a second region representing the rest of the world, with which Switzerland trades at a given price. In Panos et al. (2021), through the SCCER JASM project the database of STEM was further improved and the model's degree of detail of the Swiss energy system extended. Through the SCCER network a flow of knowledge and data between the teams involved was created; this led to a significant improvement in the STEM model which this study has benefitted from (Panos et al., 2021).

The present report has used the rich characterisation of the Swiss electricity demand for end-use service provided by the STEM model, notably in its variant of the CLI scenario of SCCER JASM (Panos et al., 2021). For the present study, temporal resolution was further improved to 8 760 hours per year (see Chapter 3). The supply side for the different scenarios instead was developed on the basis of the NEA's POSY model according to data, hypotheses and assumptions that were entirely independent of STEM.

2.5. The NEA initiative on system cost modelling for member countries (SC3)

In 2012 the NEA launched an innovative programme on the study of system costs and the impact of changes in the configuration of electricity systems on their costs and reliability. NEA system cost modelling makes it possible to determine the least-cost generation mix and optimal share of nuclear energy in function of different CO_2 emission reductions, renewable generation targets and a combination of greenfield (i.e. newly to be developed capacities that are optimised by the model) and brownfield (i.e. historically existing capacities that are taken as given by the model) generation sources. The current report is the first major result of the NEA SC3 initiative using advanced MILP modelling to assess the total costs of attaining a given carbon constraint with different shares of nuclear energy and VRE technologies.

As has already been remarked, results depend strongly on the specific context of each member country, and are driven by the country-specific conditions on costs, flexibility resources, carbon constraints, brownfield and greenfield generation mixes translated into time series that can be used by the algorithms of NEA's POSY model, as well as data, VRE, and CO_2 constraints. Member country stakeholders are essential to the modelling effort, helping develop policy-relevant results. Typical data requirements from member countries can include:

- Country-specific costs and performance of different technologies including load factors for VRE with their daily and annual variations;
- The hourly load curve for electricity demand;
- The amount of flexibility resources available including hydroelectric capacity, demand-side potential and the available interconnections with neighbouring countries;
- Specifying whether the assumptions adopted are for the complete long-term configuration of the system (greenfield) or a shorter-term optimisation given the existing capacity mix (brownfield);
- Indication of different policy measures to be used in terms of VRE and carbon constraints (different options are possible but require different model runs).

The purpose of such analysis is to provide energy policymakers with indications of the total systems costs of different electricity generation and energy mixes. While original system cost work has focused primarily on the electricity sector, more recent work includes "sector coupling" between the electricity sector and other parts of the energy system such as hydrogen, heat or electric vehicles. In most cases, system cost work is undertaken at the national or the regional level. System cost analysis contributes to addressing relevant policy questions, such as:

- Individual or joint costs of attaining different VRE and carbon targets;
- Impact of these targets on different technologies, in particular nuclear energy, and the overall mix;
- Decrease in the market value of VRE-generated electricity as the VRE share in the electricity mix increases;
- Role of storage and voluntary and involuntary demand response;
- Level and volatility of electricity prices;
- Key inflection points and resulting capacity mixes that define current pathways to new emission target scenarios.

System cost analysis thus provides a flexible tool for the systematic analysis of future-oriented energy policy exploring different scenarios for low-carbon electricity generation mixes. In order to be useful for the energy policy discussion under way, the particularity of NEA work in this area is to combine such electricity system modelling with clearly formulated policy objectives and instruments to attain these objectives. In the current Swiss energy policy discussion, a number of detailed energy modelling efforts have been undertaken to better understand the costs of different options to attain the objective net zero carbon emissions by 2050. However, a careful review of existing studies shows that the scenarios presented in the present study are well suited to address gaps in the current literature. This regards, in particular, the role of the LTO of Switzerland's two newest nuclear power plants as well as the decisive impact that the electricity trade and the level of interconnections between Switzerland and its European neighbours have on the costs of realising net zero in 2050.

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Chapter 3: The Swiss energy system, modelling challenges and solutions

3.1. An overview of the Swiss electricity system

The Swiss electricity system is unique. Compared to other OECD countries it is already characterised by very low-carbon intensity, a high share of flexible hydroelectric generation, and an unusually high interconnection capacity – especially when compared to Swiss generation capacity. Indeed, Switzerland's direct CO_2 emissions from electricity and heat production are among the lowest in the world. In 2019, carbon emissions from electricity and heat production were only 2.7 million tonnes, which amounted to a carbon intensity of only 38 gCO_2 per kWh (see Table 3.1). In terms of interconnections with its four neighbouring countries – Austria, France, Germany and Italy – Switzerland currently exhibits a capacity of 9 GW for electricity imports and 11.3 GW for electricity exports. This compares to a peak demand of 9.7 GW and a total generation capacity of 22 GW, or a ratio of more than 50% between export capacity and total generation capacity. In comparison, the European Union currently encourages its member states to attain the objective of 15% interconnection capacity to total generation capacity (EU, n.d).

Table 3.1. **2019 carbon intensity in the Swiss electricity sector compared to other OECD countries**

	Direct CO_2 emissions from electricity and heat production (million tCO_2)	Electricity production (TWh)	Carbon intensity (gCO_2/kWh)
Switzerland	2.7	72	38
OECD Europe	1 010	3 640	278
Austria	13	74	176
France	37	571	64
Germany	239	609	393
Italy	96	293	328

Source: OECD, 2022.

This low-carbon intensity is due to Switzerland's high shares of hydroelectricity and nuclear energy, alongside a smaller share of solar PV and wind in the generation mix. Residual emissions are due to a number of small, decentralised cogeneration plants for both industrial and domestic electricity production and heat consumption (see Table 3.2).

Although not part of the European Union, Switzerland is a key platform for European electricity trading. Strategically placed between Austria, France, Germany and Italy, Swiss flexible hydroelectric resources are an important element in balancing electricity demand and supply for its neighbouring countries. The role played by Swiss hydroelectricity is further increased by the fact that the electricity sectors of its four neighbouring countries are distinct. France, with its large share of nuclear capacity, is essentially a provider of low-cost baseload power. Italy, with a tight consumption and production balance, heavily depending on imported gas, is structurally a high-cost country. Germany, with more than 120 GW of variable wind and solar PV capacity, will export large amounts of low-cost electricity when the wind blows and the sun shines, but will require imports if this is not the case. Only Austria, Switzerland's alpine neighbour, has an electricity mix similar to Switzerland's – albeit without nuclear energy and with a larger share of biomass and waste.

Table 3.2. **Capacity and electricity production in 2019 and 2021**[1]

	2019		2021	
	Annual production (TWh)	**Installed capacity (GW)**	**Annual production (TWh)**	**Installed capacity (GW)**
Nuclear	25.3	3.3	18.5*	3.0
Hydro (run-of-the-river)	17.7	4.2	17.0	4.2
Hydro storage (reservoir and pump storage)	22.9	11.3	22.5	11.3
Wind	0.1	0.1	0.1	0.1
Solar PV	2.2	2.2	2.5	3.2
Waste	2.3	0.4	2.7	0.4
CHP and other thermal	1.4	0.5	1.5	0.5
Total	**71.9**	**22.0**	**64.5**	**22.8**

* The drop in nuclear production is due firstly to the shutdown of the Mühleberg power plant in December 2019, and secondly to the annual maintenance inspection (including refurbishment) of the Leibstadt nuclear power plant, which lasted several months (SFOE, 2021).

Source: SFOE (2019) and SFOE (2021).

Electricity trading is not only important for Switzerland's neighbours. It is also a crucial element in determining the overall costs of the Swiss low-carbon generation system. The ability to buy electricity when it is cheap elsewhere and to sell it when it is expensive is an important element for reducing costs. Looking towards the future, and in particular the different net zero scenarios in Chapter 4, one differentiating element providing options for the Swiss generation mix consists precisely of its ability to generate revenues from electricity trading. Other things equal, flexible and stable baseload sources from hydro and nuclear energy allow for considerably higher trade revenues than variable renewables whose production profiles are unaligned with the patterns of demand in surrounding countries.

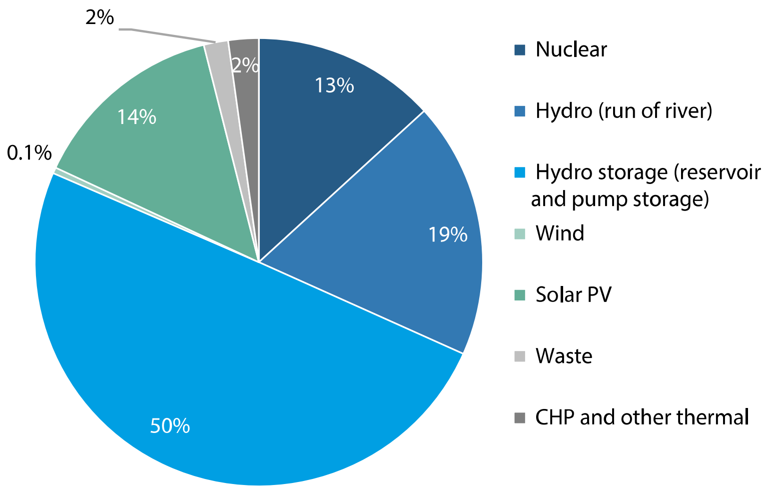
The Swiss electricity generation mix

In 2021, among its different power sources, hydroelectricity was the largest electricity generating technology in Switzerland, providing 69% of its installed capacity and 61% of its electricity (see Figures 3.1 and 3.2). It must, however, be understood that the term hydroelectricity covers three different categories of electricity generation units: run-of-the-river plants, hydroelectric reservoirs, and pump storage units. Although all three ultimately create electricity by having water pass through a turbine, converting kinetic into electric energy, they each have distinct economic characteristics and functions in the electricity system. Run-of-the-river plants may have some seasonal variations but are not dispatched on an hourly, daily or weekly basis. They thus complement Swiss nuclear power plants as providers of baseload power. Hydroelectric reservoirs are lakes created by dams that are replenished by natural sources, such as water inflows from rivers, glaciers or rain. Operators can choose when to release water and generate electricity, usually when the latter is at its most expensive, but cannot choose when to replenish reservoirs (see Section 3.2). Finally, pump storage units, as the name implies, combine a water turbine with

1. Table 3.2 provides data for 2019 and 2021. The year 2019 is of interest as it was used for the calibration of the POSY model, being the last year for which full hourly datasets were available at the time of the development of the model. It was also the last year before the onset of the COVID-19 pandemic in 2020. Using 2019 capacity figures and demand profiles, the POSY model was thus adjusted until the generation profiles and prices generated matched those observed in the Swiss system. This, subsequently, ensures more realistic and relevant results for future scenarios with different capacity mixes. 2019 was the most recent year for which detailed hourly data for demand and renewable production was available at the time of the present report's writing. Interest for the year 2021 is obvious given it is the latest full year for which some high-level data is available.

a water pump. In this case, operators will choose not only the moment when to release the stored water but also when to pump it. Logically, their economic model is built on the spread between high-price hours and low-price hours.

Figure 3.1. **2021 installed capacity (GW)**



Source: SFOE (2021).

Hydroelectric reservoirs and pump storage units are important providers of flexibility in any electricity system. Complemented by its nuclear and run-of-the-river plants as reliable baseload producers, flexible hydroelectricity allows Switzerland to engage in profitable electricity trading with its neighbouring countries. Swiss operators have considerable experience and long-established business models in this field, traditionally buying and pumping cheap electricity during the night while releasing and selling electricity during the day. In recent years, however, this business model has been challenged by large quantities of VRE capacity in neighbouring countries. The roles of wind and solar PV needs to be differentiated. Wind contributes to overall price volatility – which is not necessarily negative for the provider of flexibility services. However, large amounts of solar PV capacity in neighbouring countries such as France, Germany and Italy have reduced the price spread between night-time and daytime hours which was the mainstay of the profitability of the operators of flexible hydro facilities.

In parallel, Switzerland continues to invest in its hydroelectric resources, in particular, pump storage, which due to its flexibility is the most economically advantageous form of hydroelectricity for the country. The latest expansion of the giant Linth-Limmern pump storage complex, completed in 2017, brought the latter's total capacity to 1 480 MW. At the Nant de Drance reservoir additional pump storage capacity of 900 MW was installed, coming online in July 2022. Thus, recent developments have contributed to creating new value for flexible hydroelectricity. It allows its four owners to use six independently operating pump turbines according to their own optimisation schedules. Flexible hydro thus continues to play a key role in the Swiss electricity sector, and is expected to continue to in the future. Nevertheless, there is also some concern about water quality requirements (see Chapter 2), and the risk that climate change may reduce the water debit due to melting glaciers, on whose water most Swiss hydro facilities depend in one way or another (Swissinfo, 2021). While the issue is of manageable proportions for the time being, it is closely monitored.

Nuclear energy is Switzerland's second largest source of electricity contributing 13% of its capacity and 29% of its electricity. The annual output of nuclear power plants exceeds that of either run-of-the-river hydroelectric plants or that of reservoirs and pump storage units combined. In 2019, nuclear capacity was composed of five reactors in the power plants of Beznau 1 and 2, Gösgen, Leibstadt and Mühleberg (see Table 3.3 below). The reactor in Mühleberg has since been shut down following a complex legal case involving different levels of jurisdiction and decision-making, as well as a series of expert studies commissioned by different parties. Ultimately, it was an economic decision, because the expensive retrofitting required would not have allowed for a profitable continuation of operations. Nuclear power plants in Switzerland are operated in baseload mode, which means that they are not modulated according to prices or demand. While they are technically capable of doing so, the high share of dispatchable hydroelectricity in the Swiss generation system does away with the need for nuclear power plants to provide additional flexibility. Their load will vary, of course, in function of technical constraints, environmental regulations, and operations will cease during refuelling. Primary, Secondary and Tertiary control for balancing the grid is the responsibility of the Swiss transport system operator (TSO) Swissgrid and nuclear power plants are not involved at all.

Beyond electricity, the reactors at Beznau also produce district heating in addition to power. Beznau thus provides 80 MW of heat to industry and homes over a 130 km network serving 18 000 industrial and residential customers in 11 towns and villages (Swissnuclear, 2022).

Table 3.3. **Active nuclear power reactors in Switzerland***

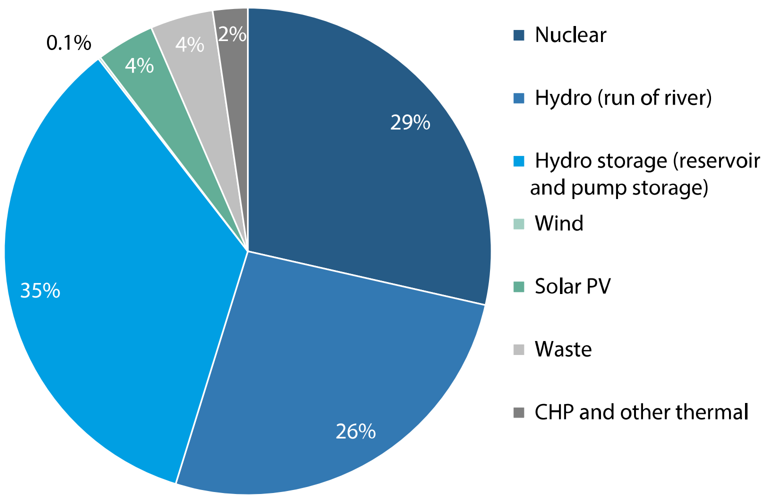
	Capacity (MW)	Year of commissioning
Beznau I	365	1969
Beznau II	365	1972
Gösgen	985	1979
Leibstadt	1 220	1984
Total	**2 935**	

* The Mülhenberg power plant was operated since 1972 and was shut down in December 2019.

Both hydroelectricity and nuclear energy are characterised by a high ratio of fixed capital costs to variable costs. In conjunction with the high level of interconnection capacity, this explains another unique feature of the Swiss electricity system: variable costs of domestic generating technologies almost never determine electricity prices. In most electricity markets the short-run variable costs of the marginal technology, typically the fuel costs of a domestic gas or coal plant, with or without a carbon adder, set the price. In the case of Switzerland, however, prices are set in a more roundabout fashion. At different times, Swiss prices can be set by a German coal plant, an Italian gas plant, a French nuclear power plant or the intertemporal opportunity cost calculation of the operator of a Swiss pump storage facility. This affects neither the efficiency nor the security of supply of the Swiss system. However, it poses several challenges to modelling the working of the Swiss electricity system, described in further detail in the following section.

It is also notable that the characteristics of electricity produced by nuclear energy coupled with the large Swiss interconnection capacity, i.e. its ability to produce large amounts of baseload power in a highly predictable manner, makes an important contribution to reducing overall economic costs of the Swiss power system. Indeed, while operated in a less flexible manner than reservoirs and pump storage facilities, nuclear baseload precisely enables Switzerland's more flexible hydro resources to concentrate on maximising profits from electricity trading rather than tending to satisfy Swiss domestic demand. If nuclear baseload was substituted instead by variable wind and solar PV, conversely, flexible hydro resources would be required to be employed to a much greater degree to ensure balance between domestic demand and supply.

Figure 3.2. **2021 Swiss electricity generation (TWh)**



Source: SFOE (2021).

In terms of non-hydro renewables, Switzerland in 2021 had an installed capacity of 3.2 GW of solar PV (up from 2.2 GW in 2019), constituting 14% of its installed capacity and contributing 2.5 TWh (up from 2.2 TWh in 2019) or 4% to electricity generation. This was complemented by 0.1 GW of onshore wind turbines with an average load factor of 13% contributing another 0.14% of generation. For geographical reasons, land use, and social acceptability, as both current practice and future projections confirm, the contribution of non-hydro renewables will be based primarily on solar PV rather than on wind. Between 2019 and 2021, the proportional increase in solar PV capacity was actually stronger than the proportional increase in its contribution to electricity generation, as the load factor fell from 11% to 9%. This is due to the fact that 2021 was a year with a number of sunshine hours somewhat below the 1991-2020 average (MeteoSwiss, 2022).

The contribution of non-hydro renewables to total electricity generation may appear modest for the time being. However, many scenarios including the reference study Energieperspektiven 2050+ (EP2050+) commissioned by SFOE (Prognos et al., 2021) foresee significant additional amounts of variable renewable energy capacity to be installed to achieve net zero emissions in its energy sector. The *ZERO* base scenario of EP2050+ estimates that Switzerland will have 37.5 GW of solar PV capacity and 2.2 GW of wind capacity which would correspond to 67% of 2050 total generation capacity (Prognos et al., 2021). The well-regarded JASM study by a consortium of research institutes led by the Paul Scherrer Institute (PSI) assumes in its Climate Policy (CLI) scenario, also for 2050, in addition to 1 GW of biofuels, a capacity of 27 GW for solar PV and 2.6 GW of wind for 58% of total VRE generation capacity (Panos et al., 2021).

In 2021, different forms of thermal power generation contributed a little less than 1 GW to Switzerland's generation capacity and 3.2 TWh, or roughly 6%, to its domestic electricity production. Thermal capacity is composed of plants for waste incineration with and without heat production in addition to electricity, industrial auto-production and decentralised cogeneration plants, some of which are based on biomass or biogas. These plants are primarily operated in a must-run mode and do not intervene in the establishment of the demand and supply balance in the electricity system through the price mechanism.

The Swiss electricity demand

Switzerland consumed 58.1 TWh of electricity in 2021. This represents an increase of 4.3% from the previous year following a steady decline of electricity consumption since 2017. This substantial increase is due to a 3.7% rebound in economic activity after the COVID-19 pandemic, a slight increase in population of 0.8%, and a higher than average number of heating days – as 10% of Swiss electricity is used for home heating. Energy efficiency improvements limited an even steeper increase.

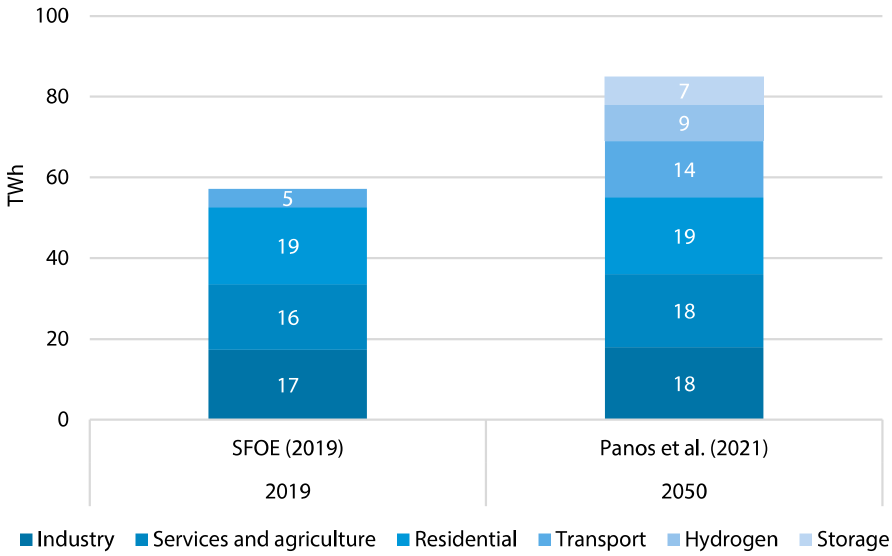
Despite its abundant hydroelectric resources, Switzerland is not a highly electrified country. Only about 25% of its energy consumption stems from electricity. This is far below highly electrified countries such as Norway, where 48% of energy is consumed in the form of electricity. In 2021, also *per capita* electricity consumption in Switzerland was up at 6 677 kWh per capita, a 3.52% increase from the previous year following an essentially steady decline since 2011, as only 2015 saw a very slight increase. Swiss *per capita* consumption is comparable with that of its neighbours, Austria, France and Germany, while Italy traditionally has a lower *per capita* consumption.

The important metric of peak electricity demand also went up in 2021 from 9.6 GW to 10.2 GW. Yet, it is not higher in 2021 than it was in 2018 (BFE, 2021). In 2021, households consumed 34.8% of electricity thus confirming the trend of a steadily rising share. Of the remainder, agriculture and forestry consumed 1.6%, industry 29.5%, the commercial service sector 26.0% and transport, including Switzerland's fabled railroads, 8%.

The evolution of electricity demand will be a crucial determinant of the feasibility and cost of Switzerland's net zero carbon objective in 2050. This evolution has two key aspects, the overall level of future demand and its distribution over the year. In the context of this report, projections for the Swiss electricity demand in 2050 were taken from the 2021 JASM study with its highly detailed representation of different end-use sectors and in particular its net zero carbon CLI scenario (Panos et al., 2021).

Annual demand (see Figure 3.3) would thus increase to 85 TWh from 58.1 TWh in 2021 and 57.2 TWh in 2019. This significant increase by almost 50% is not primarily due to increases in industry, services and agriculture, or even residential consumption. In these sectors, increasing direct electrification, for instance gas to electricity substitution in residential heating, is more or less balanced by across-the-board energy efficiency improvements. Important increases are expected to happen instead in the transport sector due to electric vehicles as well as in two new sectors that are intimately related to the deep structural transformation of the electric system by 2050. One of them is the production of hydrogen, both as a material input and as an energy vector in industry, and for some residential applications. Low-carbon hydrogen will thus complement direct electrification as a complementary, indirect form of electrification. The other structural change is electricity storage. Not counting the efficiency losses in charging/discharging, storage will likely release as much electricity as it consumes. Therefore, it does not reflect an increase in net consumption but rather indicates a destructuring of demand.

Figure 3.3. **Annual demand in 2019 and 2050**



Source: SFOE (2019) and Panos et al. (2021).

Figure 3.4 shows how total electricity demand is indeed projected to become much more volatile when moving from 2019 to 2050. Total electricity demand includes domestic demand for energy services in industry, commerce, the residential sector and transport, as indicated by the JASM study (Panos et al., 2021) as well as the needs of the electricity sector in terms of charging and hydrogen production as calculated by the POSY model. This does not only regard specific hours, but a gradual loss of the traditional patterns of consumption during the day, the week, and the season. Several factors are at play here:, first, the economically optimised charging of storage facilities, whether pump hydro and/or battery storage, and second, the charging patterns of electric vehicles that are driven by considerations other than the hourly price of electricity.

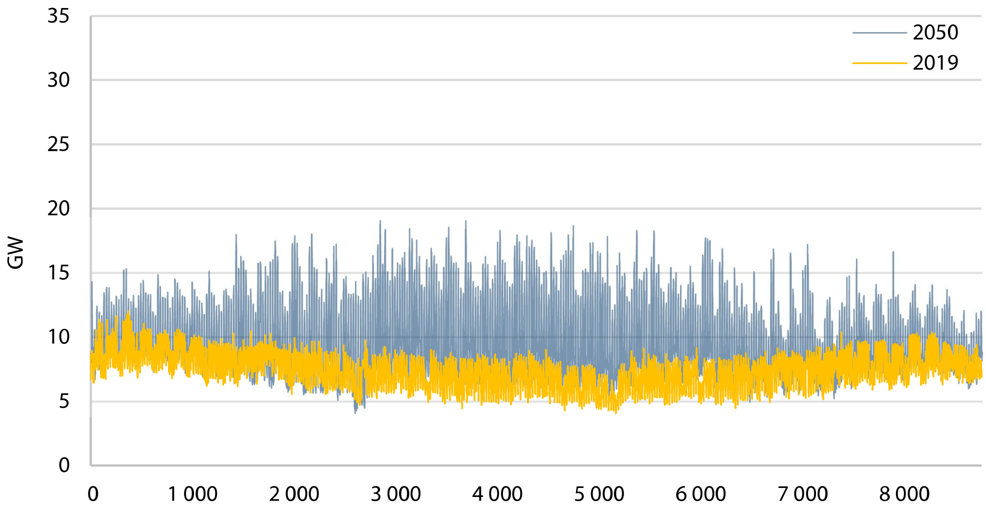
Such more volatile electricity demand is likely to create higher costs for the Swiss system through three channels:

- higher peak demand and thus higher capacity requirements;
- lower load factors for baseload technologies and thus higher average costs as fixed costs are distributed over a lower number of units;
- technical stress and higher costs for operations and maintenance as generators need to ramp up and down more frequently.

However, the structure of demand will not only depend on exogenous behavioural drivers but also on the chosen generation mix. Figure 3.4 shows the demand curve for a scenario with continuing long-term operation (LTO) of the Gösgen and Leibstadt nuclear power plants and a capacity of interconnections for electricity trade at 2021 level.

Figure 3.4. **Hourly demand in 2019 and 2050**

(LTO scenario with 100% of interconnections, GW)

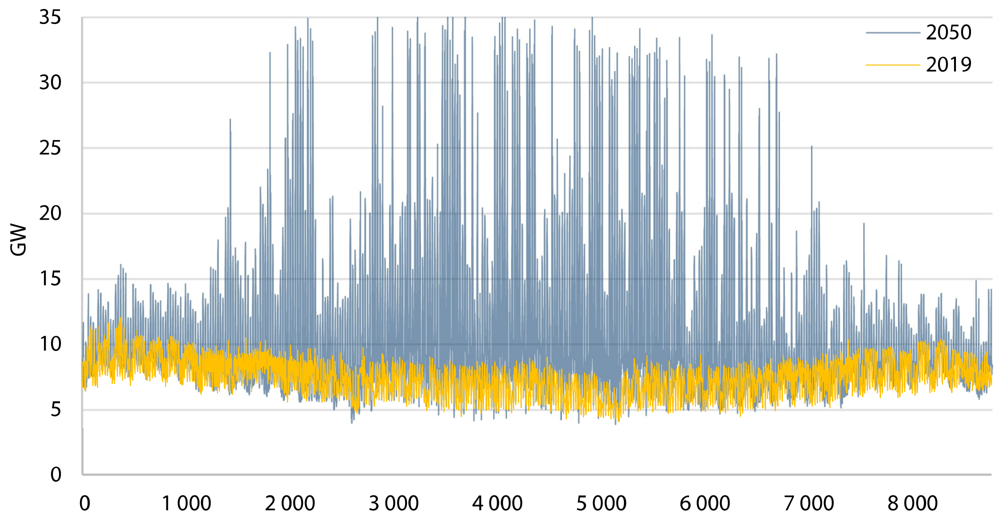


Source: Panos et al., 2021.

This can be contrasted in Figure 3.5 with a scenario based exclusively on wind and solar PV (VRE only scenario) in autarchy, i.e. without electricity trade with Switzerland's neighbours. It is easy to see, that both peak demand, as well as overall volatility of total electricity demand increase considerably, even though Swiss consumers will not have changed their behavioural patterns nor their level of energy service consumption compared to the LTO scenario. The changes in demand are entirely due to the more intensive charging patterns of flexibility providers such as pump storage facilities and batteries. The latter's contribution is required to a far greater extent in a VRE only scenario in autarchy than in a LTO scenario with full interconnection capacity.

Figure 3.5. **Hourly demand in 2019 and 2050**

(VRE only scenario in autarchy, GW)



Source: Panos et al., 2021.

Chapter 4 will explore how different generation mixes respond and interact, on the demand side, with this new reality. A valuable message from this report can already be drawn at this early stage: in 2050, generation will no longer respond mechanically to a given supply structure. Intermittency, flexibility provision and storage will ensure that electricity consumption and production will be tightly intertwined.

Different generation mixes will thus affect the demand side in very different ways. Keeping account of this increasingly close co-development of electricity demand and supply will be an important element in determining cost-effective and sustainable energy policies.

From today to net zero carbon in 2050

Overall, Switzerland currently enjoys a secure, low-carbon electricity system. Thanks to the reliability of its nuclear power and run-of-the-river hydropower, the flexibility of its hydro reservoirs and pump storage units as well as its large interconnection capacity, Swiss power generators are able to engage in profitable trading with its neighbours. This has a sizeable impact on the overall cost of the Swiss electricity system to Swiss consumers, taxpayers and citizens. Looking towards the future, there exist different options to achieve the ambitious net zero target Switzerland has set for itself by 2050. While all possible scenarios will contain substantial additional investments in variable renewable capacity, in particular solar PV, a decisive question will be whether in 2050 nuclear power, either as a result of LTO or new nuclear builds, will still contribute to domestic Swiss electricity production.

While Chapter 4 will present several detailed scenarios for a net zero electricity mix in 2050, three general insights can already be indicated. First, scenarios built on a generation mix of solar PV, wind and nuclear baseload have considerably lower system costs than scenarios with only variable renewable energy (VRE). Second, while more expensive, Switzerland's high level of domestic flexibility resources could, in principle, ensure the technical viability of a VRE only strategy if (a) the profile of electricity demand remains overall comparable to contemporary levels and, (b) the interconnections allowing for electricity trade with neighbouring countries remain open. The ability to trade internationally is an important additional flexibility resource in this context. Third, a VRE only strategy to reach net zero in 2050 *without* adequate interconnection capacity would not only be markedly expensive but would also pose risks for the security of electricity supply despite the high level of Swiss domestic flexibility resources.

These key results developed on the basis of reasonable assumptions and a sophisticated modelling tool, which will be presented in the following section, appear robust. They will constitute the parameters of the future energy policy debates that Swiss politicians, energy decision-makers, stakeholders and consumers will need to have in the years to come to ensure achieving a net zero target by 2050 while preserving current levels of security of supply and economic efficiency.

3.2. Modelling the Swiss energy system with the POSY model

The power system simulations of this study have been performed with POSY, the power system model developed by the Nuclear Energy Agency (NEA) Nuclear Technology Development and Economics (NTE) division. A short description of the tool used to perform the Swiss system analysis is given in the following section. In a second step, the input data required to run the model is described as well as the specific challenges faced in modelling the Swiss electricity system.

The Power System Model: POSY

POSY is the NEA model for evaluating the system costs of electric power systems.[2] For this purpose, investment in new electricity generation capacity and power dispatch on an hourly basis are assessed at every hour during one year, while minimising the costs of the power system. Both linear and mixed-integer linear programming can be used. POSY optimises the total cost of electricity system for a given year while ensuring balance between electricity supply and demand. For a given year, two components are calculated and optimised by POSY:

- The investment decisions in electricity generating capacity, which are also referred to as **capacity expansion**.
- The hourly operational decisions to modify the power output or switch on or off different electricity providers such as generation or storage units. In other words, the tool arbitrates the electricity production of the various technologies according to the load and to the principle of least-cost **economic dispatch**. This process of deciding which individual power units should be generating at every hour of the year is referred to as **unit commitment**.

POSY takes into account a set of components on which technologies are based (see Table 3.4). For these technologies and their associated costs, the total costs of the power system is then minimised. In POSY, economic system costs correspond to the sum of the fixed costs (including investment and fixed operation and maintenance [O&M] costs), and of the variable costs (including variable O&M and fuel costs) of all units connected to the grid, including flexibility providers on the supply and the demand side. The revenues and costs from electricity trading at the interconnections with Switzerland's neighbours are also considered in the total costs of the power system. More details on system costs are given in the next section. The equation below indicates the cost minimisation process over all domestic technologies, net import costs and demand response levers under a series of constraints (see Table 3.5), the most important of which being the balancing of demand and supply at each hour.

$$min \sum_{t=1}^{8760} \left(\sum_{i \in technologies}\left(c_i^{investment} + c_i^{fixedOM} + c_i^{varOM} + c_i^{fuel} + c_i^{waste} + c_i^{carbon}\right) + \sum_{i \in DR} c_i^{varDR} + \sum_{i \in IC} c_i^{IC} + c^{curtail}\right)$$

2. POSY is written in the Julia programming language, and uses the JuMP package for mathematical optimisation (Dunning, 2017). It is available open source at www.oecd-nea.org/tools/abstract/detail/nea-1929/.

With:

- $c_i^{investment}$: annualised investment cost per technology
- $c_i^{fixedOM}$: fixed O&M cost per technology
- c_i^{varOM} : variable O&M cost per technology
- c_i^{fuel} : fuel cost per technology
- c_i^{waste} : waste management cost per technology
- c_i^{carbon}: carbon cost per technology, represented as carbon production multiplied by carbon
- c_i^{varDR} : variable demand response cost (incl. voluntary and involuntary demand response)
- $c^{curtail}$: curtailment cost from VRE
- c_i^{IC} : interconnection cost or revenue per interconnection

Table 3.4. **Components of the Swiss electricity system modelled in POSY**

General technologies or settings	Brief description	Corresponding technologies or settings in the Swiss grid
Dispatchable	Plant production is dispatchable and follows unit commitment. Therefore, POSY considers constraints such as up and down ramping limits, minimum power output, startup and shutdown patterns, and minimum uptime and downtime.	• OCGT • CCGT
"Must run"*	Same characteristics as dispatchable, except that the committed units are set to operate at full power. Planned stops for fuel reloading, for example, can also be taken into consideration.	• Nuclear LTO • Nuclear new build
Intermittent	The electricity production follows an exogenous profile based on historical time series.	• Solar PV • Onshore wind • Run-of-the-river hydro • Waste incineration and CHP
Storage	Those facilities can store and, if needed, charge or discharge energy within charging and discharging capacity limits. The quantity of energy stored is also limited and is subject to a storage efficiency factor. For hydroelectricity power, it can be subject to external intake (e.g. water inflow in water reservoirs). Generation is considered dispatchable, without the unit commitment feature that is not considered in storage technologies because on/off switching constraints are not relevant at the considered timescales.	• Pumped storage hydro • Reservoir based-hydro • Battery
Electrolysers	Hydrogen is generated from electricity by electrolysis.	• PEM (proton exchange membrane)
Demand response (DR)	Both voluntary and involuntary demand response are modelled in POSY. Voluntary DR is limited hourly by a maximal capacity; it is also referred as demand-side management (DSM). In contrast, involuntary demand response, i.e. load shedding is, potentially unlimited.	• Demand-side management (voluntary demand response) • Load shedding (involuntary demand response)
Interconnections**	POSY models trade with neighbouring countries based on least-cost dispatch. Imports and exports volume are calculated in the range given by the hourly exogenous net transfer capacities (NTC) for each time step, and the exogenous spot price time series given for each neighbouring country.	• Imports and exports volumes • Austria, France, Germany, Italy are the neighbouring countries
System	This category can bear additional components such as transmission losses, and primary and secondary reserves.	• Losses only

* In Switzerland, nuclear power plants are operated in baseload mode, i.e. they produce at nominal power rate at all times. Load-following is not a mode operated, and is not planned in the future. In addition, Swiss nuclear power plants do not participate in successive frequency controls.

** As an economic model geared towards cost minimisation, POSY takes into account only commercial flows of electricity as opposed to physical flows. As is well known, the latter follow the laws of Kirchhoff, which means that bilaterally contracted commercial flows can pass through third countries or even through loop flows crossing the border several times in both side of the interconnection. To some extent the impact of loop flows on interconnection capacity available for commercial transactions is reflected by taking into account not the physically available transfer capacity (ATC) but only the net transfer capacity (NTC) that deducts the transmission reliability margin (TRM). The NTC values taken into account by POSY correspond to capacity available for commercial flows.

The optimisation algorithm of POSY includes capital investment costs and operating costs (fixed and variable O&M, fuel, carbon and waste) which are subject to a number of technical constraints based on the nature of the technology. These constraints (see Table 3.5) strengthen the technical representativeness of the modelled system. Prior to the description of the constraints, a set of parameters and variables have to been defined.

- $\bar{P}_i$: net capacity of dispatchable technology i (MW)
- $\underline{P}_i$: minimum power of dispatchable technology i (MW)
- SU_i : startup capability of dispatchable technology i (MW)
- SD_i : shutdown capability of dispatchable technology i (MW)
- SUD_i : startup duration of dispatchable technology i (hours)
- SDD_i : shutdown duration of dispatchable technology i (hours)
- $V_{i,t}$: profile of intermittent technology i at time t (dimensionless)
- $\overline{DR}_i^h$: hourly maximum of demand response lever i (MW)
- $\overline{DR}_i^y$: yearly maximum of demand response lever i (MWh)
- x_i: investment decision per technology i (dimensionless for committed technologies; MW otherwise)
- $u_{i,t}$: unit commitment of technology i at time t (dimensionless)
- $v_{i,t}$ and $w_{i,t}$: startup and shutdown of technology i at time t (dimensionless)
- $p_{i,t}$: power above min power for committed technology i at time t (MW). This is the "dispatchable" power output of dispatchables, the other part being linked to minimum power output. $\hat{p}_t = \sum_{i \in technologies} \hat{p}_{i,t}$is the expression of the total power output
- $\hat{p}_{i,t}$: total power for technology i at time t (MW)
- $DR_{i,t}$: demand response per lever i at time t (MW)
- $DR_t = \sum_{i \in DR} DR_{i,t}$: expression of the total demand response
- C_t: production curtailment at time t (MW)
- D_t: total domestic demand at time t including T&D losses (MW)
- $\hat{e}_{\omega st}$: total energy output (MWh)
- $\hat{c}_{\omega st}$: charged energy for storage (MWh)
- $c_{\omega st}$: charged power for storage (MW)
- $\phi_{\omega st}$: energy storage level (MWh)
- $\gamma_{\omega st}$: binary decision parameter for charging or discharging
- $\bar{X}_j$: Investment limit for technology j
- X_j^0: Initial capacity for technology j.

The POSY model has been developed within the NEA and has been calibrated and validated according to the following two main features. First, the time step evaluated in the POSY model is one hour periods for an entire year, i.e. 8 760 hours, and representing the future for each of the 8 750 hours of the year 2050 that is calculated in this study. Therefore, POSY produces a snapshot of the minimum-cost generation mix under a set of exogenously predefined future conditions for each hour of the year.

Second, POSY uses mathematical optimisation techniques such as linear programming (LP), and mixed-integer linear programming (MILP) to solve the cost minimisation problem. LP focuses on optimised cases in which the cost objective function is linear and the constraints are specified using only linear equalities and inequalities. On the other side, MILP solve linear equations in which variables can be constrained to take an integer value. It is thus designed to solve far more complex problems than in regular LP. MILP allows, in particular, to integrate technical constraints of different technologies, such as ramping constraints, minimum up and down times, must run conditions etc. that substantially increase the technical realism of the electricity system studied. A full taking into account of unit commitment is possible only by MILP.

The advantage of MILP to optimise a wide variety of generation mixes, taking into account both investment and dispatch ranges not only to technical constraints but may include also policy choices, regulatory constraints or other constraints of a different nature. Naturally, the mathematical challenge grows with the number of constraints because the number of possible combinations of on/off integer constraints with the possible capacity expansion and unit commitment decisions for each time step of the year increases exponentially.

Table 3.5. **Example of technical constraint modelled in POSY**

Constraint	Brief description
Commitment	• Only built units can be committed: $0 \leq u_{i,t} \leq x_i$ • Starting and shutting down constraint: $u_{i,t} - u_{i,t-1} = v_{i,t} - w_{i,t}$
Link between power above minimum and commitment	Power above minimum is determined by commitment, as well as startup and shutdown capabilities: $0 \leq p_{i,t} \leq (\overline{P}_i - \underline{P}_i)u_{i,t} + (SU_i - \underline{P}_i)v_{i,t} - (\overline{P}_i - SD_i)w_{i,t+1}$
Intermittent production	The production is equal to the production profile multiplied by the installed capacity: $\hat{p}_{i,t} = V_{i,t}x_i$
Fast dispatchable technologies production	$\hat{p}_{i,t} = \underline{P}_i(u_{i,t} + v_{i,t+1}) + p_{i,t}$
Slow dispatchable technologies production (case with linear, gradual startup/shutdown)	$p_{i,t} = startup(i,t) + up(i,t) + shutdown(i,t)$ With: $startup(i,t) = SU_i \sum_{h=2}^{SUD_i} \left(\frac{h-1}{SUD_i} v_{i,(t-h+SUD_i+2)}\right)$ $up(i,t) = \underline{P_i}(u_{i,t} + v_{i,t+1} - w_{i,t+1}) + p_{i,t}$ $shutdown(i,t) = SD_i \sum_{h=1}^{SDD_i} \left(\frac{SDD_i+1-h}{SDD_i} w_{t-h+2}\right)$
Storage	• Avoiding charging and discharging at the same time: $\forall \omega, s, t$ $\hat{c}_{\omega st} \leq (1 - \gamma_{\omega st}) * (X_s^0 + \overline{X_s})$ and $\hat{e}_{\omega st} \leq \gamma_{\omega st} * (X_s^0 + \overline{X_s})$ • Definition of storage inventory $\forall \omega, s, t \quad \phi_{\omega st} = \phi_{\omega st-1} + \hat{c}_{\omega st} - \hat{e}_{\omega st}$
Demand response	• Hourly maximum of demand response: $DR_{i,t} \leq \overline{DR}_i^h$: • Yearly maximum of demand response: $\sum_{t \in T} DR_{i,t} \leq \overline{DR}_i^y$
Production and demand balance (supply constraint)	The sum of the total power output (including storage technologies), demand response and net imports must be equal at the total demand (incl. transmission losses, storage charging and H_2 production) and the production curtailment at each time step: $\forall \boldsymbol{t}, \quad \boldsymbol{\hat{p}_t} + \boldsymbol{DR_t} + \boldsymbol{IC_t} = \boldsymbol{D_t} + \boldsymbol{C_t}$

Sources: Gentile (2017), Morales-España (2014), Morales-España (2015), Morales-España (2017), Morales-España (2018), Palmintier (2011), Palmintier (2014) and Tejada-Arango (2020).

At the system level, the total capacity of all generating units including VRE is represented as a continuous decision variable, except for large thermal units such as nuclear power plants, which are represented as an integer cluster. Individual capacity units for solar PV, wind, run-of-the-river hydro or gas plants are all small enough to justify the hypothesis of a one single continuous decision variable, while larger units such as nuclear require unit clustering. Thanks to a judicious choice regarding these questions on how best to represent the Swiss power system in different situations, the LP and MILP features of POSY allow for increased richness in other scenarios and a reasonable computation time.

Input data used in the Swiss system cost study

A set of generating technologies has been explicitly represented and modelled in this study: small units of thermal power generation, combined cycle gas turbine (CCGT), nuclear on the basis of LTO or new build, solar PV and wind, waste incineration, combined heat and power (CHP) and three types of hydroelectric facilities (run-of-the-river, pumped storage, and reservoir based). Flexibility levers included in the study are battery storage, voluntary and involuntary demand response, as well as hydrogen production. The study has not included technologies that are currently not deployed at an industrial scale such as carbon capture and storage (CCS), power-to-gas. While hydrogen production for industrial purposes is included, no hydrogen-to-power conversion is modelled. Prior to the optimisation, the operating (fixed and variable) and capital costs (from investments) as well as the exogenous parameters necessary for the tool are identified in the next paragraphs.

Available technologies and their associated costs

Fixed and variable costs for generation and storage technologies are mainly derived from the last edition of the IEA/NEA *Projected Costs of Electricity Generation: 2020 Edition*, which assesses projected costs for power plants to be built in 2025 in OECD countries mainly (IEA/NEA, 2020). Some data points have been adjusted after consultation with stakeholders to take into account specificities of the Swiss electricity system. While Switzerland participated in IEA/NEA 2020, data had not been provided for all technologies. In other cases, newer data had become available. Table 3.6. synthesises the most relevant economic data used in this analysis.

Fixed costs of generating plants include the annuities for investment costs as well as the annually fixed O&M expenditures. Investment costs result from overnight costs (OC) for a specific construction time, financing costs and decommissioning costs. Costs are annualised according to the load factor, the expected lifetime and the discount rate of 5%. This is in line with other studies of the Swiss electricity system, which consider in general a discount rate from 2 to 6% (Fuchs et al., 2017; Panos et al., 2021; Pattupara et al., 2016; Panos et al., 2018). Moreover, this rate is applied in an identical way to all technologies (e.g. nuclear energy, VRE or hydro) with only a very low share of gas in the studied power system. The choice of discount rate can be crucial in determining the competitiveness between capital-intensive low-carbon technologies such as VRE, hydro or nuclear on the one hand and fossil fuel-based technologies such as coal or gas on the other. However, in the specific context of a study of the Swiss electricity sector in a net zero context, the choice of discount rate, while still important for absolute cost levels, has minimal impact on the *relative costs* of different scenarios. Nuclear energy, hydro and VRE being of comparable capital intensity suffer or benefit in more or less equal measure from changes in the discount rate.

Table 3.6. **Cost assumptions for generating plants, storage capacities and flexibility levers**

				Fixed costs		Variable costs			
Technology	**Duration of operation**	**Decomm. costs**	**Overnight costs***	**Annual inv. costs (@5%)**	**Fixed annual O&M**	**Variable O&M**	**Fuel costs**	**Carbon costs**	**Waste costs**
	years	*% of OC*	*USD/kW*	*USD/MW/y*	*USD/MW/y*	*USD/MWh*	*USD/MWh*	*USD/MWh*	*USD/MWh*
New nuclear build	60	15%	4 013	247 632	106 180	0	7	0	2.33
Nuclear LTO	20	15%	550	46 672	96 202	0	7	0	2.33
Onshore wind	25	5%	1 458	104 852	38 000	0	0	0	0
Solar PV	25	5%	1 000	70 952	25 000	0	0	0	0
Hydro – run-of-the-river	80	5%	3 012	153 701	42 500	0	0	0	0
Hydro – reservoir	80	5%	3 108	158 600	20 000	0	0	0	0
Hydro – pump storage	80	5%	2 662	135 841	20 000	0	0	0	0
Gas – OCGT	30	5%	590	38 380	14 599	5.56	138.3	54.73	0
Gas – CCGT	30	5%	895	58 221	26 024	3.50	85.3	33.67	0
Incineration	40	5%	2 433	101 266	17 148	3.92	0	0	0
CHP	40	5%	2 951	223 436	17 451	3.50	0	0	0
Battery storage	15	5%	484	46 630	9 001	0	0	0	0
Hydrogen production	20	5%	500	40 121	1 204	0	70*	0	0
Demand response	-	-	0	0	0	300	0	0	0
Load shedding	-	-	0	0	0	10 000	0	0	0

* Following IEA/NEA (2020), p. 38, overnight costs include contingency payments of 15% for nuclear new build and 5% for all other technologies including nuclear LTO. ** Variable costs of H_2 depend on the electricity generation mix, in this overview table results for the LTO scenario are presented.

Source: As detailed in the text, all data is derived from IEA/NEA (2020), or based on information from Swiss stakeholders.

Operating and maintenance costs are split into fixed and variable costs. Variable costs comprise fuel, waste management, carbon and variable O&M costs. In the following paragraphs more details are given for the fixed and variable costs calculation of each technology listed in the Table 3.6.

- Nuclear LTO: Overnight costs and all other costs and data correspond specifically to Switzerland (IEA/NEA, 2020).
- New nuclear costs come from the costs of the French EPR (IEA/NEA, 2020), which also explains the choice of modelling nuclear new build in increments of 1.6 GW. Solar PV takes into account both residential and large-scale solar panels. A single value has been kept for overnight and fixed O&M costs representing an average value between those of Italy and Austria, due to Switzerland's geographical proximity to these two countries.
- Costs of wind power, which by definition is onshore in Switzerland, are considered similar to Austria. Load factors for both solar PV and wind derived from the JASM study (Panos et al., 2021). These values are on the high side but in line with expectations for technical advances in the further use of VRE.
- Hydroelectricity: the cost values were obtained as the median of responses for European OECD countries (IEA/NEA, 2020). For hydro reservoir only high capacity builds above 5 MW were considered. In addition, the realised load factors of run-of-the-river "fatal" hydroelectric resources are based on the real data of the Swiss electric power system (SFOE, 2019) obtained from the 2019 calibration exercise (see following section for more details).
- Gas (CCGT and OCGT) costs correspond to the median of all OECD countries. Total O&M costs from IEA/NEA (2020) are split into fixed and variable O&M costs. Nevertheless, considering the rise in gas prices following the COVID-19 pandemic in 2021 and geopolitical events in Ukraine, it was decided to use a gas price of USD 50 per MWh for gas-fired power plants. While this is considerably lower than prices observed in European gas markets during 2022, it constitutes a reasonable estimate of the gas price in a long-term 2050 perspective. Efficiency factors of 37% (resp. 60%) for OCGT (resp. CCGT) are then applied to calculate updated fuel cost. Gas technologies, as CO_2-emitters, are subjected to a carbon cost of USD 100 per tCO_2. This value can also be considered as the abatement cost of carbon capture and storage or of investments in carbon compensation such as reforestation. In other words, the study assumes that with a USD 100 carbon price, carbon costs are fully offset.
- CHP and waste incineration: the costs of CHP plants are considered to be equal to the average of biomass costs in IEA/NEA 2020, since cogeneration plants in Switzerland are mainly fuelled by carbon-free sources (biomass or biogas). Furthermore, the costs of waste incineration are based on those of coal, as waste combustion from a thermodynamic cycle point of view can be considered as close to a coal cycle. Identically to hydro run-of-the-river, the realised load factors of waste incineration, CHP sources are based on real data of the Swiss electric power system (SFOE, 2019) obtained from the 2019 calibration exercise (see Section 3.3).
- Battery storage costs are derived from available estimates of lithium-ion battery, with an overnight cost of almost USD 500 per kW (IEA/NEA, 2020). In comparison, Lazard's 2021 Levelised Cost of Storage Analysis estimates the capital costs of a 100 MW/1 000 MWh battery system at USD 51 to 148 per MWh (Lazard, 2021).
- Hydrogen production by proton exchange membrane (PEM) electrolysis has been modelled in the study. Cost data is based on internal NEA expertise in accordance with international values from NEA (2022) on nuclear and hydrogen. The variable costs for hydrogen production, i.e. the cost of the electricity needed to operate the electrolysers, are endogenous to each simulation and depend on the electricity generation mix and thus on the electricity market price.
- Demand-side management (DSM) has been modelled in the study as the possibility to curtail up voluntary to a maximum of 1.4 GW of the load at a cost of USD 300 per MWh. A value of lost load of USD 10 000 per MWh is assumed for involuntary demand response, i.e. load shedding.

Exogenous parameters: hourly time series for 2050

For optimisation, POSY requires both input parameters such as the costs presented above, but also exogenous data to model the specific year. For this purpose, the series are mainly taken from the study conducted by the Joint Activity Scenarios and Modelling (JASM) which includes the Paul Scherrer Institute (PSI), the Ecole Polytechnique Fédérale de Lausanne (EPFL), the University of Basel, and is supported by the Swiss Federal Office of Energy (Panos et al., 2021). However, some modifications to the JASM inputs, which are sampled (i.e. not all 8 760 hours are available), were conducted on the Swiss demand, the production profiles of the fatal renewable energies, and sport prices. These changes have been made in order to provide hourly data for one full year after a re-normalisation process that made the updated data compatible with POSY for 2050. Data for interconnection use comes from ENTSO-E website. Table 3.7 summarises the input data used by POSY and indicates their associated reference. In a second step, an empirical representation of the different time series (prices, VRE production and demand) is provided to illustrate the consistency of their respective use for the simulation phase.

Table 3.7. **Times series used by POSY model and their associated sources**

Hourly chronicles	Reference	Remarks
Swiss demand (final consumption except for losses)	Panos et al., 2021	Renormalised with 2019 values (BFE, 2019)
Normalised production profiles: • VRE (PV and onshore wind) • Hydro run-of-the-river • CHP and incineration	JASM platform (Panos et al., 2021) Inspired by Panos et al., 2021	2012 data Weekly time series
Natural water intake from hydro reservoir*	Panos et al., 2021	Renormalised with 2019 values (BFE, 2019)
Swiss neighbouring spot prices	Panos et al., 2021	2040 prices in EUR An exchange rate of CHF 1.12 to USD has been applied
Hourly net transfer capacity (NTC) of interconnectors	2019 data of ENTSO-E platform	Divided by the interconnector capacities taken from JASM data platform

* The water intake is given in percentage and represents the hourly intake in MW multiplied by the 1-hour time step divided by the total potential energy of the clustered reservoir (e.g. 8 850 MWh).

Hourly electricity prices in Switzerland's four neighbouring countries were provided through the JASM platform on the basis of the Swissmod energy market model of the University of Basel (SCCER, 2022; Schlecht and Weigt, 2014). Among the different scenarios the *decarb* scenario, the most ambitious in terms of carbon reductions, was chosen. Illustrative weeks of each season of neighbouring prices (Austria, France, Germany and Italy) as well as the total VRE (solar PV and onshore wind) generation are plotted in the Figures 3.6a and 3.6b. First of all, it can be seen that the seasonality of Swiss prices is pronounced. In winter and autumn, to a lesser extent, Swiss and neighbouring prices are variable and relatively high, while during spring and summer prices are regular (daily patterns at a lower level).

The Swiss prices calculated by POSY are also presented in the Figures 3.6a and 3.6b. They are in the range of the prices in neighbouring countries. France generally seems to have a low price due to the cheap cost of amortised nuclear energy, while Italian prices are volatile and high because of few dispatchable energy sources of its own and heavily depending on imports. These phenomena are highly visible in winter. Finally, on these curves, the Swiss prices closely match either the German prices, or Austrian prices due to the high level of interconnection with both countries.

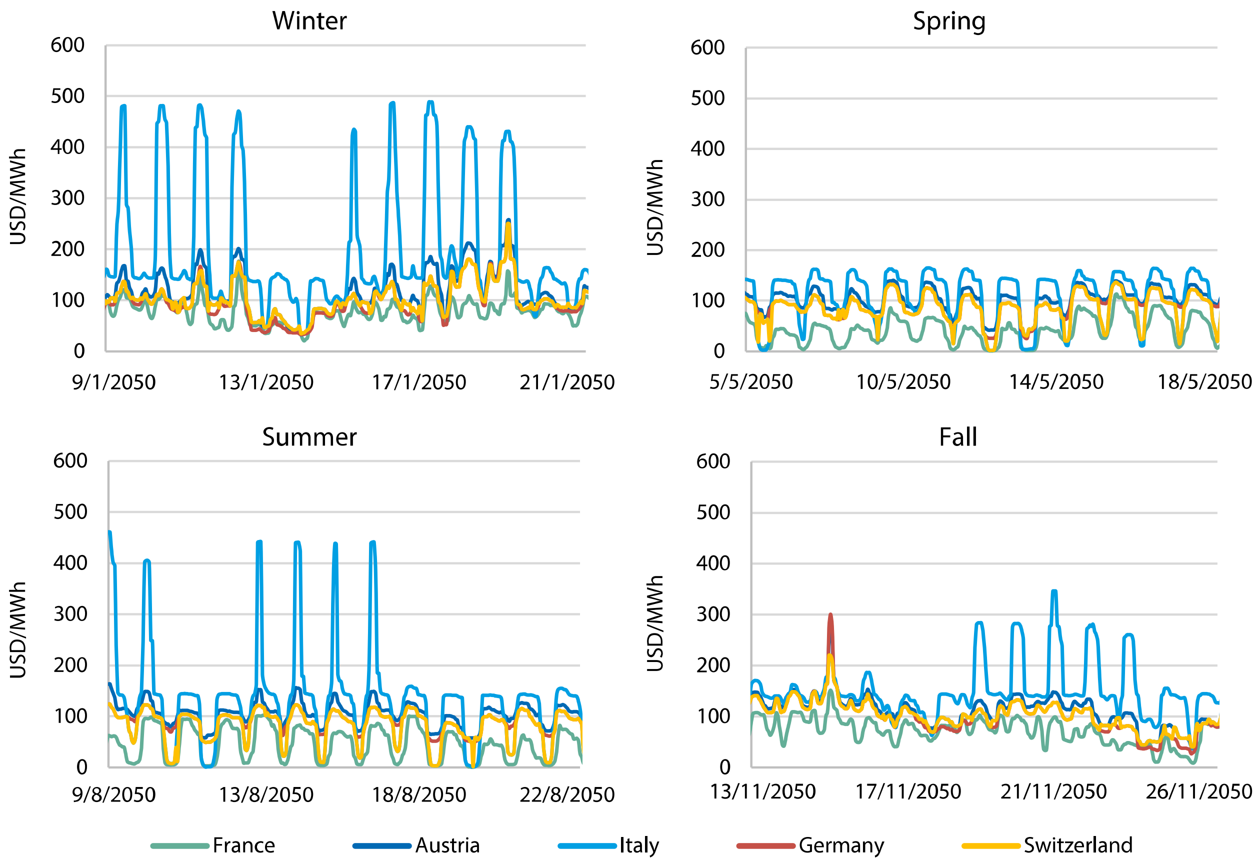
Box 3.1. **Methodology for fitting projected demand from (Panos et al., 2021) to POSY model based on Fourier transformation**[3]

The 8 760 hours time series required by POSY for 2050 is generated from the 288 time slices calculated in the JASM study (Panos et al., 2021) through a method based on a Fourier transformation. In order to calculated the expanded time series of 8 760 hours of the demand for 2050 to be used by POSY, the following time series are used in the transformation process:

- Expanded historical reference time series of 8 760 hours of the demand in 2019 (SFOE, 2019);
- Collapsed reference time series for 2019 demand, calculated from the previous expanded series;
- Collapsed target time series for 2050 demand (Panos et al., 2021).

The Fourier transformation is calibrated between both collapsed series of 2019 and 2050. The same transformation is applied to the expanded 2019 series to get the 2050 one, which will be used by POSY. Note that, the selected time series must be the same for 2019 and 2050 (for instance: 24 hours per day of 3 typical days for each of the 4 seasons). The Fourier transformation is performed under the assumption that the same transformation can be applied to generate the collapsed target from the collapsed reference and to generate the expanded target from the expanded reference.

Figure 3.6a. **Two illustrative weeks for each season of 2050 prices in Swiss neighbouring countries**



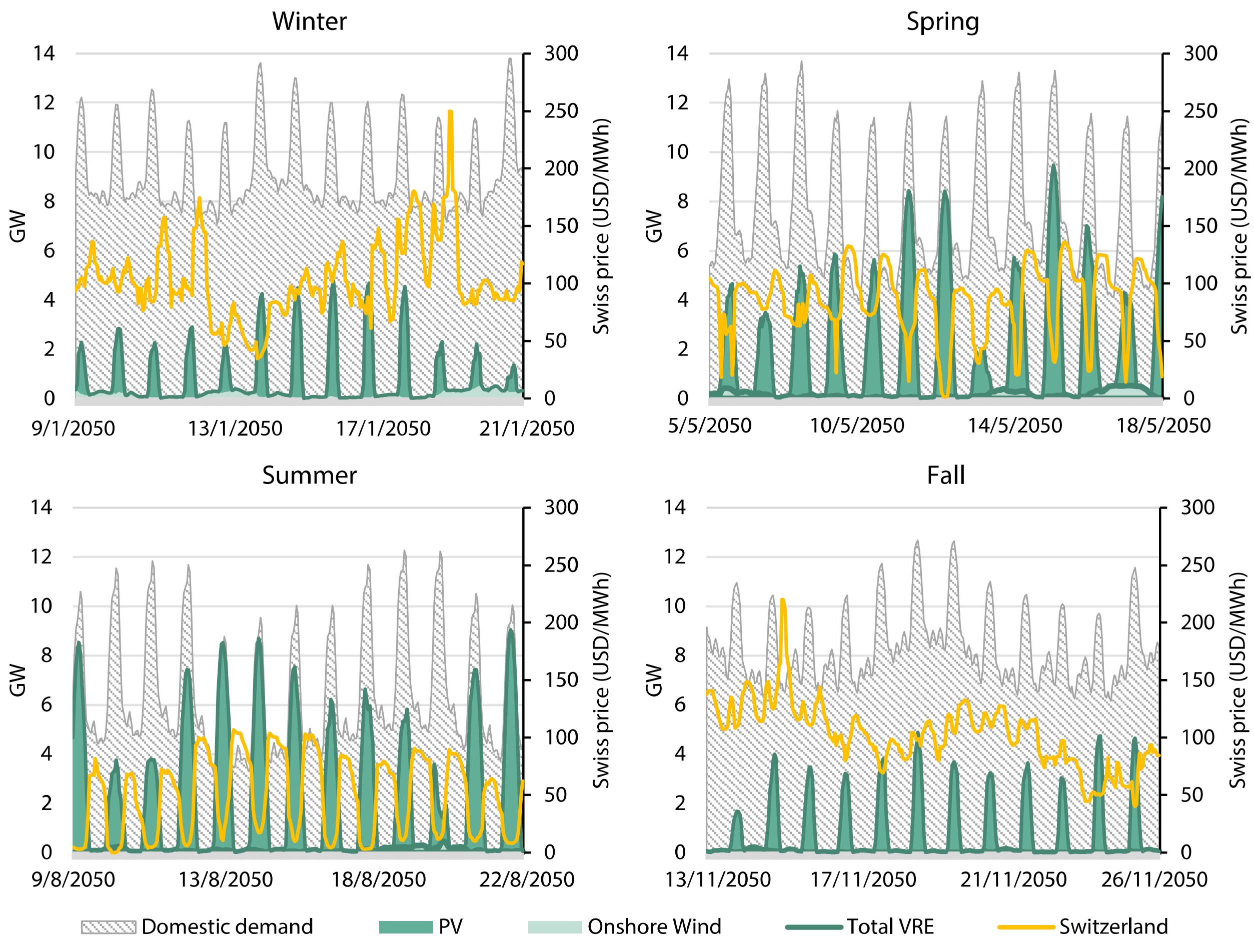
Source: The Swiss internal price is derived from the POSY simulations based on exogenous neighbouring countries prices from JASM study (Panos et al., 2021).

3. The package developed to perform this operation is available open source at https://github.com/GKrivtchik/RescaleTimeSeries.

To check the consistency between the exogenous price data in neighbouring countries and the exogenous Swiss VRE profile in 2050, generation from variable renewable energy sources were plotted against prices (see Figures 3.6a and 3.6b).

It can be seen that the lower prices in spring and summer correspond to peak production of these sources. For the rest of the year, this phenomenon can be observed to a lesser extent because solar PV and wind production is lower and subject to volatility. Although the data are derived from a variety of references, these graphs show that the modelled trends are broadly realistic. The use of these data was therefore validated as an input assumption for the 2050 scenarios.

Figure 3.6b. **Two illustrative weeks for each season of 2050 internal prices in Switzerland and the associated demand and VRE production**



Source: The Swiss internal price is derived from the POSY optimisation based on exogenous neighbouring countries prices from JASM study (Panos et al., 2021). Domestic demand and VRE production are taken also from the JASM study.

Addressing specific modelling challenges in the Swiss context

This section covers modelling challenges specific to the Swiss power system, such as the high share of hydroelectricity, the high amount of interconnections and their consequences for price calculation and trade.

- **Dominance of zero marginal cost technologies and price setting:**

  Due to the high share of hydroelectricity in the Swiss mix, combined with nuclear and, to a lesser extent CHP and waste incineration, which are operated as must run, in addition to fatal VRE generation, no source of domestic electricity generation is dispatched on the basis of short-run marginal costs in order to determine the price of electricity in

Switzerland. The price setting mode in Switzerland is indeed one-of-a-kind. In terms of modelling, instead of relying on the usual methodology of marginal cost pricing, where the price is equal to the variable costs of the marginal source, Swiss prices are determined in relation to prices in neighbouring countries except when interconnections are closed (autarchy case). Table 3.8. synthetises the different situations:

– **At least one interconnection is open:** in this case, the Swiss price is assumed to be equal to the price in the neighbouring country at the open interconnection with the lowest price;

– **All interconnections are saturated or under autarchy:** in the case, the model calculates the Swiss price as the dual of the supply constraint.[4]

Table 3.8. **Interconnection configuration of the scenarios and price calculation**

	Interco	Interco50	Autarchy
Description	2019 interconnection capacities	Half of 2019 interconnections capacities	No interconnection, Switzerland relies on internal energy capacities only
Price model	Calculation of the Swiss price assumed to be equal to the price at the open interconnection with the lowest price		POSY calculates the Swiss price as the dual of the supply constraint

- **International electricity trade requirements, interconnection capacities and cost of imports:**

  Switzerland, due to its central geographical position, is highly interconnected with other European country, and this consequently brings a number of benefits to the economy and society in terms of market integration, integration of renewables, and security of supply. One of the advantage is that Switzerland can profit from arbitraging between the price differences with neighbouring countries and thus raise its trade revenues at the interconnection. Such arbitrage generates a congestion rent CR_c, which consists of the profit created by buying lower-priced electricity in one country and selling it in another at a higher price and is measured by the price differential multiplied by the interconnection capacity, as shown in the equation below. Congestion rent is assumed to be shared evenly between two participating countries.

$$CR_c = \frac{1}{2} \sum_{c_i \epsilon C_n} f_{c,c_i} * ({p_c}^e - {p_{c_i}}^e)$$

With:

- f_{c,c_i}: flow from Switzerland (c) to country c_i (positive if outgoing flow)
- p_c, p_{c_i}: electricity price in country c and neighbouring country c_i
- C_n: set of countries connected to country c

4. In linear optimisation, to any primal problem (here, with POSY, the identification of quantities that minimise the system costs under a supply constraint), a dual problem is associated (the identification of prices that ensure cost coverage for a given output level). The sensitivity of the primal problem solution to a binding constraint in the vicinity of the solution is equal to the value of the dual variable of the constraint. As an example, the dual variable value of the power supply constraint at each hour is the power price at each hour. In the case of a MILP problem, it is often possible to approximate the dual by dualising the linearised approximation of the problem.

Congestion rent is always positive and reduces the cost of electricity imports from the importing country and measures the benefits of exports for the exporting country. POSY makes the assumption that when the interconnectors between Switzerland and another countries are used, but not saturated (i.e. f_{c,c_i} is within the range of the NTC for exports and the NTC for imports NTC between Switzerland and country c_i), then the prices between Switzerland and country c_i align (i.e. $p_c{}^e = p_{c_i}{}^e$). The practical impact of this hypothesis is that the price in Switzerland will generally align with the price of one of its neighbours, except when demand response levers are used.

An exception to this congestion rent phenomenon is the structural flows. Structural flows refer here to power flows that are not negotiated in the electricity spot market. Instead, they correspond to economic flows contractually decided on the basis of long-term contracts based on stable average prices, independently of spot market transactions. In the case of the simulation of year 2019, we considered a structural flow of 1.2 GW from France to Switzerland. Structural flows, however, are absent from the simulation of future scenarios.

3.3. Calibration and validation exercise of the 2019 Swiss case

The study of five 2050 net zero scenarios in Switzerland uses the advanced POSY modelling tool. In order to be sure to be able to capture the characteristics of the Swiss electricity sector, the model is calibrated and validated over the 2019 reference data published by the SFOE (2019) with a triple objective. First, this exercise confirms the validity of the tool as applied to the Swiss case, i.e. to reproduce the 2019 behaviour of the Swiss system which means verifying the models considered (technical constraints, interconnections, dispatch equilibrium, etc.) and checking the validity of the data used for the cost hypotheses (see Table 3.6). Second, some assumptions, e.g. the behaviour over the year of hydroelectric resources, can only be inferred from the reality of the Swiss system. The simulation of the year 2019 makes it possible to identify them. Finally, this 2019 case serves as a reference for relevant energy policy decision, by setting a border between past brownfield and future greenfield costs.

Several quantities are closely observed in the following as they are specific to the Swiss power system and serve as inputs to the model. These include the variation of the water level in reservoirs over the year, the nuclear production profile, the Swiss market price, the import and export volumes and the yearly production volumes of each technology.

Hydropower modelisation and water level validation

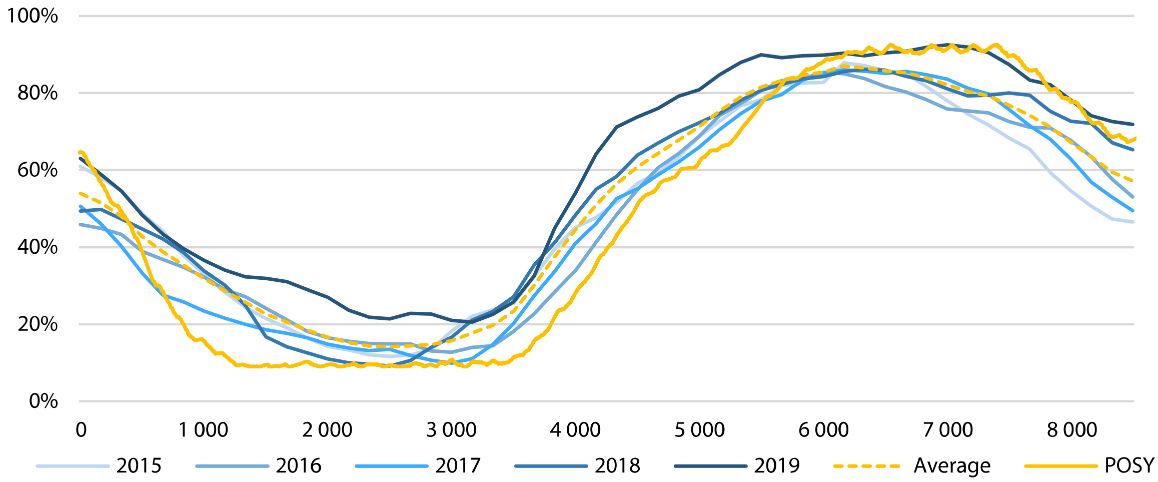
Hydropower is a highly performing source of storage and flexibility. Modelling it correctly is of great importance, in particular in scenarios with high share of variable solar PV and wind. The hydro model of POSY is based on the exhaustive list published by the Swiss officials of all hydro facilities in Switzerland (SFOE, 2022a). The power and water volumes of the reservoirs are summed up and classified into three (3) groups of facilities: run-of-the-river, hydro reservoir and pump hydro stations[5]. The model is expected to slightly overestimate the flexibility of the system since the volume limitation of each reservoir cannot be considered. Individual natural constraints may indeed reduce the flexibility of the overall system beyond what can be assumed for one large reservoir of the same size. Hydro networks between the single plants are not modelled either. This is an additional degree of freedom for the real existing Swiss system that is not considered and may compensate to some extent the possible overestimation mentioned previously.

Hydroelectric reservoirs are large collections of water behind a hydroelectric dam that makes use of potential energy of water for generating electricity. In Switzerland, the share of this resource in the mix, i.e. more than 25% of the installed capacity, is massive, so the modelling of the storage

5. Each of the three groups of facilities is modelled in POSY as aggregated into one virtual reservoir (except Nant de Drance which has been put in operation in July 2022 and is considered separately). This implies that the water network linking the reservoirs is not modelled in the contrary to the level of detail reached in (Schlecht and Weigt, 2014).

capacity is of prime importance. Figure 3.7 shows the normalised water level[6] over the five years between 2015 and 2019 and the average of these five years in dotted line. First, it can be seen that 2019 is an exceptional year as the water level is very high, otherwise the profile is similar for the other years and the average curve can be considered as an aggregated reference year. Second, the water level resulting from the optimised used of hydro facility in 2019 follows the same pattern as the reference. This is a good demonstration that the resource optimisation realised by POSY correspond to the real use of the water storage capacity over the year. The fact that the water level calculated by POSY decreases more than the real one in the first months of the year is due to the fact that the model optimises on the basis of perfect foresight for all agents. In reality, both uncertainty and informational symmetries exist. For instance, in the model, hydro reservoirs are emptied in January/February to maximise revenue because prices are high at that period, while in reality water is kept available due to the option value of possibly selling at even higher prices later.

Figure 3.7. **Normalised water level of Hydro reservoir from 2015 to 2019**



Note: Each year has been normalised by the maximal capacity reservoir which differs slightly from one year to the next. In 2019, 100% is equivalent to 8 850 GWh.

Source: Data for 2015 to 2019 are from SFOE (2022b).

Nuclear production profile validation

Following constraints are considered in the modelisation:

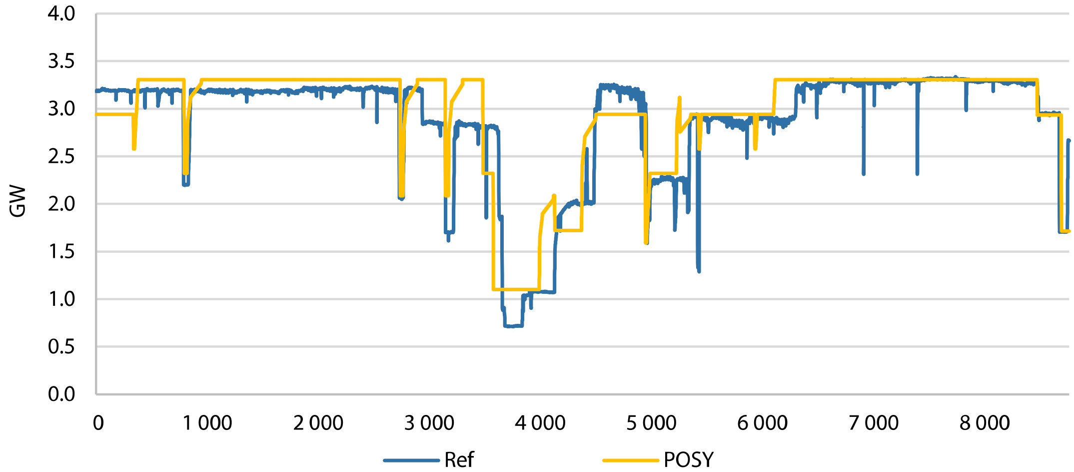
- Forcing all nuclear reactors to be online 1 January 2019;
- Forcing historical unplanned outages of nuclear plants;
- Forcing exactly one fuel reloading stop per nuclear plant (except Mühleberg) in the summer, assuming no maintenance in the Winter;
- Forcing no fuel reloading for Mühleberg;
- Forcing Mühleberg final off in December 2019.

It can be observed in the Figure 3.8 that the nuclear production modelled by POSY emulates well the real data taken from ENTSO-E. One can also note that the ramping model of nuclear technologies for shutdown and start up is in line with reality. On the contrary, the power variation around the nominal value linked to the pressure variations inside the condenser is not modelled and do not appear on the POSY power curve. Like for the water level in reservoir, POSY manages to reach a high degree of reproduction of the Swiss electricity system in 2019.

6. For 2019, the water level was anchored to historical data from SFOE (2019) at the first and last hour of the year (hours 1 and 8 760). The rest of the level profile is optimised by the model. When optimising future scenarios, the constraint on the level is so that the level at the first and last hour of the year must be equal. This prevents the model from depleting all the reservoirs.

It should be noted that for the 2050 simulations including nuclear power facilities, one stop for refurbishment per unit between May and October is permitted.

Figure 3.8. **Total nuclear power production in 2019**



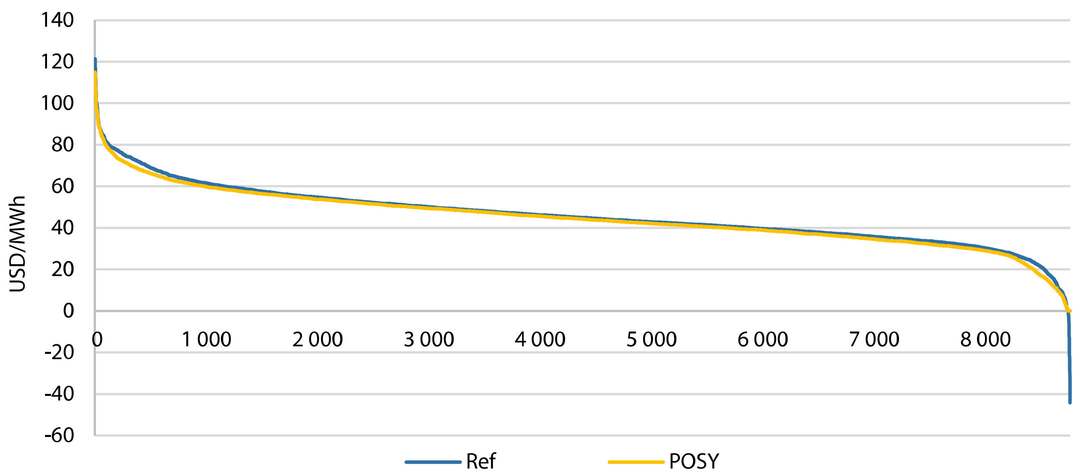
Source: Reference case data is taken from ENTSO-E (2022).

Swiss market price validation

After focusing on the modelling of two decarbonised productions, it is of interest to look at the price modelling used in POSY as it is very specific to the Swiss case. As mentioned several times before, the Swiss market price determination is unique since the price is governed by the price of neighbours and not by the marginal cost. At each time step, the price is the one of the latest country whose interconnection is not saturated.

The price duration curve in Figure 3.9 shows that the model used is consistent. Indeed, the price curve obtained with POSY is almost identical to the reference. The only difference relies in the range of negative prices which are not reproduced by the model. Indeed such option is not available in POSY. The evaluation of negative prices is complex in two aspects. First, for modelling simplicity, it seems sufficient to assume zero prices in situations where supply, for example from VRE production, exceeds demand. This is based on the second argument, which is to assume that the curtailment of VRE production is costless and available up to the maximum production.

Figure 3.9. **2019 price duration curve**



Source: Reference case data is taken from ENTSO-E (2022)

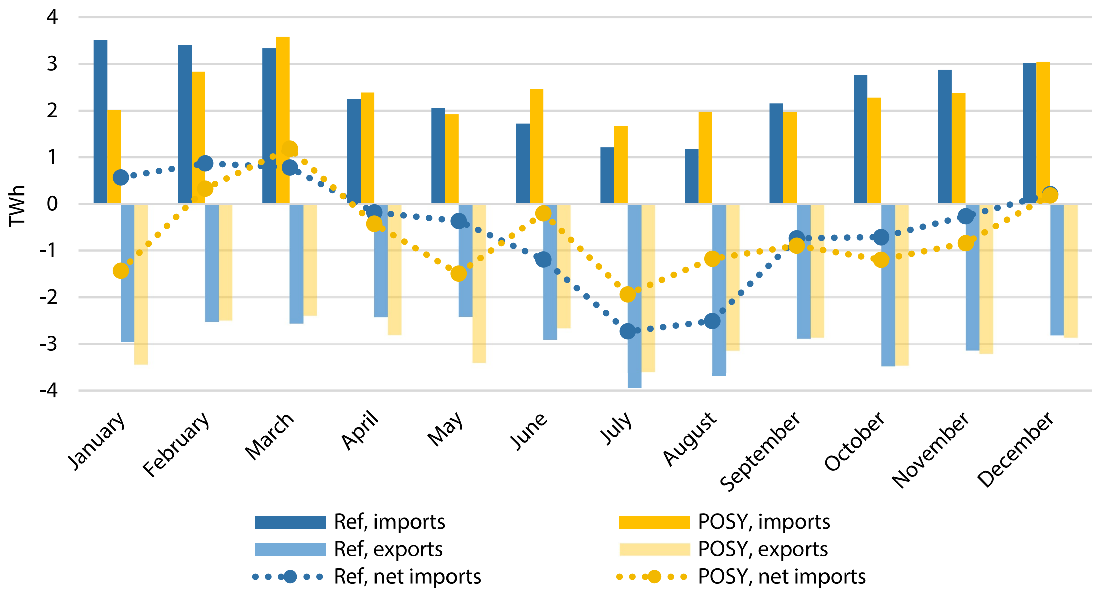
Import and export volumes validation

Figure 3.9 shows that the price model is correct and can therefore be used for the study of the scenarios to 2050 but it is also import to validate the cross-border flows calculated by the model. For this purpose, Figure 3.10 compares the commercial flows each month between reality and the results of POSY for the year 2019. Despite slight differences between reality and the model, especially in the winter and autumn months, the overall results are really good.

There are several related reasons for the remaining deviations. First, it is necessary to come back to the fact that POSY is a model whose main objective is to optimise the balance between production and consumption. However, *a priori*, POSY has, as input data, the production profiles of renewable energies, hydro run-of-the-river, CHP and waste and the intake of water in the hydro reservoirs for each time step. Consequently, POSY has *perfect foresight*: each decision (e.g. unit commitment) is made in full knowledge of the entire year ahead, while real-world system operators do not have that knowledge and must advance on the basis of probabilistic reasoning.

The disadvantage of operators is threefold: firstly, they cannot know the production profiles perfectly in advance over the year. They only have seasonal trends or feedback from previous years. Second, even if the predictions for VRE are getting better, they are still not accurate or real-time. The calculation of the dispatch is consequently dependent on the data which are accessible to the operators or to the model at time *t*. Third, an operator must also take into account constraints for future years, in particular for the management of water in hydraulic reservoirs and storage. For instance, in the model, hydro reservoirs are emptied in the beginning of the year, as shown in Figure 3.8 to maximise revenue because prices are high at that period, while in reality water is kept available due to the option value of possibly selling at even higher prices later. In addition to this modelling issue, POSY assumes that all electricity trades are spot market only (except the 1.2 GW structural flow from France to Switzerland, as mentioned above), while in reality bilateral over-the-counter trades also exist.

Figure 3.10. **Monthly physical flows in 2019**



Source: Reference case data is taken from SFOE (2019).

Consequently, all these reasons may have an impact on hourly dispatch calculation of electricity. *A fortiori* it can lead to a difference in interconnection flows between model and real data. Yet, POSY as a cost minimisation tool in principle reproduces, by virtue of duality, the outcome of the profit optimising decisions of electricity traders and operators. Careful modelling calibration and validation should thus leave room for only a small gap between reality and modelling.

Generation mix validation

Finally, Table 3.9 shows the comparison between the generation mix obtained with POSY for the year 2019 and the actual values obtained from the Swiss Federal Office of Energy (SFOE, 2019). Some of the table data such as CHP and waste productions as well as the Swiss domestic demand are exogenous inputs and remained fixed during calculation. Hence, in these cases the error between reality and model is zero by construction.

In general, it can be seen that annual production values are very close to reality. The only difference above 5% is hydro storage which takes both pumped hydro and hydro from reservoir. It is here that the question of perfect foresight in the model and probabilistic reasoning in reality has the most acute consequences. The reason for differences in the case of interconnection flows is the same: real-world traders face uncertainties that the model can anticipate fully.

Overall, however, one can conclude that the validation exercise of calibrating the POSY model so that it generates an electricity mix as close as possible to the real Swiss electricity mix of 2019 performed quite satisfactorily for the electricity mix. Employing POSY for the analysis of five 2050 net zero scenarios in Switzerland (see Chapter 4) could thus be approached with good confidence.

Table 3.9. **Comparison of 2019 generation values of the Swiss generation mix**

	Reference	POSY	*Error*
Annual production (TWh)			
Nuclear	25.3	26.02	*3%*
Hydro run-of-the-river*	17.7		
Hydro storage (reservoir and pump storage)	22.9	23.61	*3%*
Wind**	0.1	0.12	*4%*
Solar PV**	2.2	2.09	
Waste*	2.3		
CHP and other thermal*	1.4		
TOTAL	71.9	73.3	*2%*
Demand (TWh)			
Hydro pumping	4.1	3.79	*7.6%*
Losses	4.30	4.38	*2%*
Final consumption*	57.2		
Interconnection flows (TWh)			
Yearly imports	29.5	28.49	*3%*
Yearly exports	35.8	36.37	*2%*

* The final consumption, as well as hydro run-of-the-river, and CHP and waste production profile are hourly inputs of the model.

** This computation was performed with load factors of 11% and 18% for PV panels and wind onshore, based on (IEA/NEA, 2020).

Source: Reference case data is taken from SFOE (2019).

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Chapter 4: Total system costs of different net zero carbon scenarios in 2050 for Switzerland: Results from the NEA POSY model

4.1. Switzerland's options for attaining net zero in 2050: Five scenarios for a low-carbon generation mix at varying levels of interconnection

Switzerland's objective to achieve net zero carbon emissions in 2050 is ambitious, but not unrealistic. Its large hydro-electric capacity and high level of interconnections for electricity trading, and potentially importing electricity, provide a solid foundation towards this endeavour. Hydroelectricity and imports alone, however, will be unable to fulfil low-carbon electricity needs, in particular as transfers from other sectors such as heating and transport will significantly increase Swiss electricity demand by 2050. The key strategic question is therefore which technologies will provide the remainder of electricity supply. There essentially exist three basic options, which this report develops in the form of five scenarios under different conditions for electricity trading: (a) a mix of nuclear energy and variable renewables (VRE) such as solar PV and wind, (b) a VRE only strategy based on solar PV and wind alone, or (c) a mix of VRE and natural gas. In the latter case, residual carbon emissions would need to be either captured and stored or compensated by investing in carbon abatement elsewhere in order to satisfy the net zero carbon constraint. The cost of such abatement or compensation measures was set at USD 100 per tCO_2.

Due to the high costs of carbon emissions or, alternatively, of carbon capture and storage, a natural gas scenario was included in this report for reasons of methodological completeness rather than any consideration of natural gas as a central option in Swiss energy policy. In addition, geopolitical developments in Ukraine and their impacts on the European gas market have markedly increased doubts about security of supply and affordability of natural gas. At the heart of the debate on how to achieve net zero carbon emissions in 2050 in a manner that ensures both the security of electricity supply that Swiss consumers have grown accustomed to, and affordable costs, lies a single question: should Switzerland's future low-carbon mix be based, in addition to hydroelectricity, on a mix of nuclear energy and variable renewables, or on variables renewables alone? In this context, the contribution of nuclear energy could come in the form of a continued exploitation of existing nuclear power plants, largely concerning the Gösgen and Leibstadt plants, or, hypothetically, in the form of one or two newly built Generation III+ nuclear power plants.

Deciding between a mix of nuclear energy and VRE, or a VRE only strategy, touches upon a host of political, regulatory, and societal concerns. Amongst other aspects, it would reflect a choice between an electricity system relying on a combination of centralised and decentralised generation options on the one hand, and a far more decentralised system on the other, each one with distinct governance structures, technical challenges and land-use issues. While these issues will undoubtedly play a role in public discussions, this report concentrates on the economic and electricity market implications of different scenarios for attaining net zero emissions in the electricity sector under a given supply constraint, i.e. ensuring that the demand of Swiss electricity consumers is not subjected to involuntary demand response measures such as rolling blackouts during scarcity hours.

From an economic perspective, the choice between nuclear energy on the one hand, and VRE on the other, can be subsumed to the trade-off between two categories of cost, plant-level production costs on the one hand and system cost on the other. As far as plant-level production costs are concerned VRE, both solar PV and wind, have lower capital investment costs per kW than nuclear energy. Depending on the load factor that is realised this can translate also into comparatively lower unit or average costs per kWh of solar PV or wind, as is established in levelised costs of generating electricity (LCOE) calculations. However, as the analysis in this chapter will show, the costs of the overall system will be higher at higher shares of VRE due to increasing needs for dispatchable back-up. While Swiss hydroelectricity resources among others can provide such backup, the resulting economic opportunity costs are high as output from dispatchable sources can thus no longer be used to generate value in electricity trade. Another manner to consider the same fact is that at increasing penetration levels VRE generate less and less value per kWh due to the auto-correlation effect, as solar PV installations tend to produce during the same hours and equally all wind turbines tend to turn at the same moment. At higher penetration rates, the output of VRE will even need to be curtailed during high production hours in order to main network stability, which de facto implies a zero price.

In comparison, baseload electricity provided by nuclear energy, despite its higher capital investment costs, conversely has more attractive system characteristics and thus implies lower overall system costs (see the general discussion in Section 2.3 and the specific implications in the present context in Section 4.2 below for a detailed discussion of the nature of system costs). Constant production over time means that there is no need for back-up capacity to maintain the supply and demand balance. Therefore, the costs for flexibility provision are reduced, and Switzerland could decrease its electricity imports and increase its exports, improving its trade balance.

The debate about pathways for attaining net zero in 2050 is therefore intrinsically linked to another intensely discussed energy policy concern: what should be the degree of integration of the Swiss electricity system with its four neighbours – Austria, France, Germany and Italy? As indicated in Chapter 3, at the level of the electricity system, Switzerland is highly integrated with its European neighbours. One measure of this integration is the elevated share of imports and exports compared to total consumption, another the unusually large interconnection capacity between Switzerland and its neighbours. There are, of course, unique reasons for this. The very diverse generation mixes in France, Germany, and Italy, alongside the high flexibility of Switzerland's reservoirs and pump storage installations, giving rise to multiple complementarities, and therefore economic opportunities.

The five aforementioned scenarios of the Swiss electricity sector in 2050 have been modelled by the Nuclear Energy Agency's (NEA) POSY MILP optimisation model in three different trade constellations to take into consideration the rising concern about the future integration of the Swiss electricity market in the European Union. Indeed the end of formal discussions with the EU regarding an electricity agreement in 2021 have been announced (Swiss Federal Council, 2021), as explained in Section 1.5:

1) Swiss interconnection capacity in 2050 will be same as in 2022 and trade relations with the European Union in the electricity market continue without change;
2) Switzerland will attempt to attain net zero emissions in autarchy, i.e. all interconnections with neighbouring countries will be closed;
3) Swiss interconnection capacity will be reduced from 2022 levels by 50% thus limiting but not terminating electricity exchanges with its European neighbours.

Modelling results show a strong interaction between assumptions about the shares of nuclear energy, VRE and gas in a net zero generation mix and electricity trading conditions. In general, one can retain that maintaining interconnection capacity at current levels will reduce the costs in all five net zero scenarios. However, reducing the level of interconnection capacity will also heighten the contrast between different net zero scenarios. Interconnection capacity is a flexibility resource that is most urgently needed in the VRE only scenario. Without interconnections and the ability to import or export electricity, a VRE only scenario would not only be expensive but would also move the Swiss electricity system further away from a resilient supply and demand balance despite the important flexibility contribution of hydroelectricity.

In the context of these three constellations of Switzerland's electricity trading relations with its European neighbours, this report was developed based on a close reading of Swiss energy policy, with five technically feasible scenarios capable of ensuring net zero carbon emissions in the electricity sector in 2050. All five scenarios assume the same security of supply constraint. This means that while the costs of the distinct scenarios differ greatly, more than doubling in certain cases, the generation mix in all five scenarios satisfies the same given demand for energy end-use services at every hour of the year. All five scenarios additionally assume the same level of hydroelectric resources, whether run-of-the-river, reservoir, or pump storage, as well as the same capacity of flexibility options.

Regarding hydroelectric resources, the assumption was made that their capacity would be the same in 2050 as in 2022, i.e. including the capacity addition in Linth-Limmern and the newly commissioned Nant de Drance pump hydro stations. This means that all scenarios include 4.19 GW of run-of-the-river capacity, 8.8 GW of hydro reservoirs and 3.58 GW of pump hydro installations. Unsurprisingly, there are numerous reasons why Swiss hydroelectric resources might be higher or lower in 2050 than in 2022. However, on balance, both sets of arguments carry a roughly equal weight. This holds equally for the 0.87 GW of thermal capacity, that consists of gas-fired capacity, waste incineration plants, and small-scale co-generation plants – some of which are operated with biomass. The assumption that both hydroelectric and thermal capacity in 2050 will be the same as in 2022 is plausible. It also facilitates the intuitive understanding of the costs drivers behind the differences in the modelling results of the five scenarios.

Regarding the options for flexibility provision in addition to reservoir and hydro pump storage, the model disposes of up to 1.4 GW of voluntary demand response and as much battery capacity as required. The imposed production hydrogen with 8 TWh of electricity provides additional flexibility (for a detailed discussion of the contribution of different flexibility providers see Section 4.5 below).

In order to provide a meaningful contribution to a structured debate about energy policy options for attaining net zero carbon emissions in Switzerland, this report therefore analyses the following five scenarios (see Tables 4.1a, 4.1b and 4.1c for detailed capacity mixes). It should be kept in mind, that the LTO and the VRE only scenario are the two central scenarios analysed in this report. The primary function of the nuclear new build and the gas scenarios is to provide a more complete overall picture rather than constitute a full-fledged alternative to key scenarios:

1) The **LTO** scenario assumes that in addition to the existing hydro capacity, Switzerland disposes of 2.2 GW of nuclear capacity. This capacity would be provided based on the continuing operations of the nuclear power plants at Gösgen (KKG) and Leibstadt (KKL). KKG would have 71 years of operations in 2050 and KKL 64 years. Such LTO would, of course, depend on the approval of the Swiss Federal Nuclear Safety Inspectorate, or the Eidgenössisches Nuklearsicherheitsinspektorat (ENSI). Yet, such operation duration of nuclear power plants are increasingly common. As mentioned in Chapter 1, in the United States, a majority of the fleet has obtained a licence renewal that allows operations for up to 60 years, and six reactors have obtained for an additional licence renewal allowing operations for up to 80 years (NEA, 2021: 39). In addition to the 2.2 GW of nuclear baseload capacity, the POSY model generates as much solar PV and wind capacity as required complemented by the necessary flexibility resources (voluntary demand response, batteries, and hydrogen production).

Table 4.1a. **Capacity mixes of five net zero scenarios with 100% of interconnection capacity (GW)**

	LTO	VRE only	New nuclear 3.2 GW	New nuclear 1.6 GW	New gas
Hydro run-of-the-river	4.19	4.19	4.19	4.19	4.19
Hydro reservoir	8.8	8.8	8.8	8.8	8.8
Pump hydro	3.58	3.58	3.58	3.58	3.58
Solar PV	11.15	18.31	8.4	13.06	18.3
Wind	0.68	1.17	0.5	0.81	1.17
Nuclear	2.21	0	3.2	1.6	0
Existing thermal	0.87	0.87	0.87	0.87	0.87
Gas (CCGT)	0	0	0	0	2
Batteries	0	0	0	0	0
Total capacity	**30.9**	**36.35**	**28.96**	**32.33**	**38.33**
Demand response	1.40	1.40	1.40	1.40	1.40
H_2 electrolysis	1.82	2.77	1.72	1.94	2.78

2) In the **VRE only** scenario, as the name implies, the POSY model adds as much solar PV and wind capacity as required, as well as flexibility resources (voluntary demand response, batteries, and hydrogen production) to satisfy the supply constraint. Unsurprisingly this is a scenario with very high overall capacity due to the low load factors of solar PV and wind. Despite the relatively modest capital costs of VRE capacity, this is thus a comparatively expensive scenario. Given the realities of the Swiss policy debate, the share of solar PV and wind in the generation mix was fixed at a ratio of 9/1, i.e. 90% of the contribution of VRE to the electricity supply will be provided by solar PV and only the remainder by wind. This constraint was also applied to the VRE contribution in all other scenarios. An unconstrained optimisation would have favoured wind on economic grounds as its higher capital costs would have been more than offset by its considerably higher load factor. However, for reasons of aesthetics, land-use, and policy preferences, as comparison Swiss models find, it is highly likely that under almost all circumstances the bulk of the VRE contribution in Switzerland will be provided by solar PV.

3) The **New nuclear 3.2 GW** scenario assumes that two newly built Generation III+ nuclear reactors would provide 3.2 GW of nuclear baseload. The rest of the required low-carbon electricity would again be provided by solar PV and wind. There would be no long-term operation of KKG and KKL in 2050 in this case. There is currently no legal basis for nuclear new build in Switzerland, so this scenario must be considered a pure thought-exercise. Even more so than in the case of the LTO and VRE only scenarios, its role is to enable a broad and informed discussion on Switzerland's energy policy choices rather than to pre-empt them on current legal frameworks.

4) The **New nuclear 1.6 GW** scenario assumes that one newly built Generation III+ nuclear reactor would provide 1.6 GW of nuclear baseload. The rest of the required low-carbon electricity would again be provided by solar PV and wind. Additionally, there would also be no LTO of KKG and KKL in 2050. The same disclaimer as in the New nuclear 3.2 GW scenario applies.

Table 4.1b. **Capacity mixes of five net zero scenarios under autarchy (GW)**

	LTO	VRE only	New nuclear 3.2 GW	New nuclear 1.6 GW	New gas
Hydro run-of-the-river	4.19	4.19	4.19	4.19	4.19
Hydro reservoir	8.8	8.8	8.8	8.8	8.8
Pump hydro	3.58	3.58	3.58	3.58	3.58
Solar PV	19.17	33.12	12.72	22.7	27.74
Wind	1.23	2.18	0.79	1.47	1.81
Nuclear	2.21	0	3.2	1.6	0
Existing thermal	0.87	0.87	0.87	0.87	0.87
Gas (CCGT)	0	0	0	0	2
Batteries	0	1.9	0	0	0
Total capacity	**39.46**	**54.06**	**33.57**	**42.63**	**48.41**
Demand response	1.40	1.40	1.40	1.40	1.40
H_2 electrolysis	1.87	2.60	1.45	2.58	5.62

5) The **New gas** scenario assumes 2 GW of dispatchable gas-fired capacity as well as a carbon price of USD 100 per tonne of CO_2. The remainder of generation needs are again provided by existing hydroelectric resources and VRE. No nuclear power generation is assumed in this scenario. The high carbon price can be considered as the opportunity costs of carbon capture and storage (CCS), or of carbon abatement, for instance through reforestation schemes in non-European countries. In other words, operators of Swiss gas-fired power

production would be assumed to have such measures in place in order to avoid paying the carbon price. Alternatively, the carbon price can be considered as providing financial resources for a public organism to engage in CCS or carbon abatement. In either case, the net zero carbon constraint would be respected. However, in the POSY model, gas-fired power generation that needs to expend these carbon costs is ultimately rarely employed despite its attractive technical qualities since costs are simply too high, and less expensive alternatives are available. It has already been remarked that geopolitical developments in Ukraine make additional gas-fired generation an even more challenging proposition.

Five scenarios under three different trade constellations make for 15 different sets of results. Tables 4.1a, 4.1b and 4.1c contain the detailed capacity established by the POSY model's least-cost calculations for each scenario. As indicated, all 15 scenarios are prepared with a common of an exogenously set annual demand curve for electricity end-use services with 8 760 hours. All of them are, of course, also compatible with the objective of net zero carbon emissions.

As indicated, not all scenarios are of equal importance. The LTO and the VRE only scenarios with 100% of the current capacity for interconnections are most likely the principal scenarios to structure the current Swiss energy policy debate on how to achieve net zero carbon emissions in 2050 cost-effectively. Other scenarios, rather, provide spotlights that permit studying special issues of importance to different Swiss stakeholders. With this in mind, one can already anticipate three more general insights of the detailed results presented in Sections 4.3 to 4.5 below:

Table 4.1c. **Capacity mixes of five net zero scenarios with 50% of interconnection capacity (GW)**

	LTO	VRE only	New nuclear 3.2 GW	New nuclear 1.6 GW	New gas
Hydro run-of-the-river	4.19	4.19	4.19	4.19	44 670
Hydro reservoir	8.8	8.8	8.8	8.8	8.8
Pump hydro	3.58	3.58	3.58	3.58	3.58
Solar PV	14.52	23.45	11.25	16.78	22.73
Wind	0.91	1.52	0.69	1.07	1.47
Nuclear	2.21	0	3.2	1.6	0
Existing thermal	0.87	0.87	0.87	0.87	0.87
Gas (CCGT)	0	0	0	0	2
Batteries	0	0	0	0	0
Total capacity	**34.51**	**41.83**	**32**	**36.31**	**43.06**
Demand response	1.40	1.40	1.40	1.40	1.40
H_2 electrolysis	1.87	3.96	1.70	2.04	3.64

First, scenarios built on a generation mix of VRE and nuclear baseload have consistently lower system costs than scenarios with VRE only. Second, while more expensive, Switzerland's high level of domestic flexibility resources would render a VRE only strategy technically feasible as long as (a) the profile of electricity demand remains broadly comparable to 2019 (the reference year for detailed demand data), and (b) the interconnection capacity allowing for electricity trade with neighbouring countries remain at 2022 levels. The ability to trade internationally remains an important additional flexibility resource. With reduced interconnection capacity, the strong export performance of nuclear baseload is particularly economically valuable. Third, a VRE only strategy to reach net zero in 2050 without adequate interconnection capacity (autarchy) would not only be extremely expensive, but would also move the Swiss system further away from resiliency despite the high level of Swiss domestic flexibility resources. The very high VRE capacity resulting from the combined choices of foregoing nuclear energy as well as electricity trading requires the continuous mobilisation of absolutely all flexibility resources to avoid scarcity pricing (involuntary demand response).

These three general insights, developed under a set of very reasonable assumptions and a state-of-the-art energy system model, appear highly robust. They will constitute the parameters of the future energy policy debates that Swiss politicians, energy decision-makers, stakeholders, and consumers may need to have in the years to come to ensure achieving net zero by 2050 while preserving current levels of security of supply and economic efficacy.

4.2. Fundamentals of system cost analysis

This report compares the total annual system cost of different electricity generation mixes allowing Switzerland to achieve net zero emissions by 2050. The results are thus structured by an interest to provide the costs of different generation mixes for a net zero carbon system in 2050 that are relevant for policy choices today, that is, at the time of this report's writing in 2022. This approach has three implications for the specific notion of system costs employed in this report.

The first distinction regards the difference between "total system costs", which would include connection, grid and balancing costs, and "profile costs" due to the variability of renewable energies such as wind and solar PV. The second regards the distinction between "brownfield costs" and "greenfield costs" and the third the interplay between the costs of operating the domestic Swiss system, which are referred to as "physical system costs", the net revenues from exporting and importing electricity, and the "economic system costs", which refer to the net monetary costs of satisfying the Swiss electricity demand under a net zero carbon constraint. As already mentioned in Chapter 3, the electricity trade flows from and to Switzerland are of a non-negligible size in the overall costs to Swiss citizens considering the different options for attaining a net zero carbon generating mix in 2050.

Total system costs, profile costs and balancing, grid and connection costs

The advent of significant amounts of VRE such as wind and solar PV requires a fundamental change in the manner in which the costs of different generation technologies need to be accounted for, with direct impacts on the nature of the results and their interpretation also in the present modelling effort. Comparing the LCOE costs of, say, a dispatchable technology such as gas or nuclear with the LCOE costs of a variable technology such as wind and solar PV, no longer provides, on its own, a sufficient indication of their impact on the overall costs of the system. The variability of the latter will induce, in function of the available flexibility resources such as dispatchable back-up, storage, demand response or interconnections for electricity trading, additional costs that accrue at the level of the overall system. NEA (2012) and NEA (2019) described in Chapter 2 present the total system costs of an integrated electricity system as the sum of plant-level generation costs that remain expressed in the form of LCOE, plus four distinct system cost elements – profile costs (also utilisation or backup costs), balancing costs, grid costs and connection costs.

- **Profile costs** refer to the increase in the generation cost of the overall electricity system in response to the variability of VRE output. They are thus at the heart of the notion of system effects. They capture, in particular, the fact that in most cases it is more expensive to provide the residual load in a system with VRE than in an equivalent system where VRE are replaced with dispatchable plants. A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This decreases the value for the system of each additional VRE unit including hours during which they have to be curtailed and corresponds to an equivalent increase in profile costs.
- **Balancing costs** refer to the increasing costs for ensuring system stability due to uncertainty in power generation, such as unforeseen plant outages or the inability to forecast VRE generation precisely. In the case of dispatchable plants, the amount and thus the cost of operating reserves are generally given by the larger contingency in terms of the largest unit connected to the grid, the so-called N-1 rule. In the case of VRE, balancing costs are essentially related to the uncertainty of their output, which requires a higher amount of spinning reserves in the system.

- **Grid costs** reflect the increase in the costs for transmission and distribution due to the distributed nature and locational constraint of VRE generation plants. Grid costs include the building of new infrastructures (grid extension) as well as increasing the capacity of existing infrastructure (grid reinforcement). Locations with good conditions for wind and solar PV generation may not coincide with economically or demographically dense regions with high electricity demand, incurring greater grid costs.

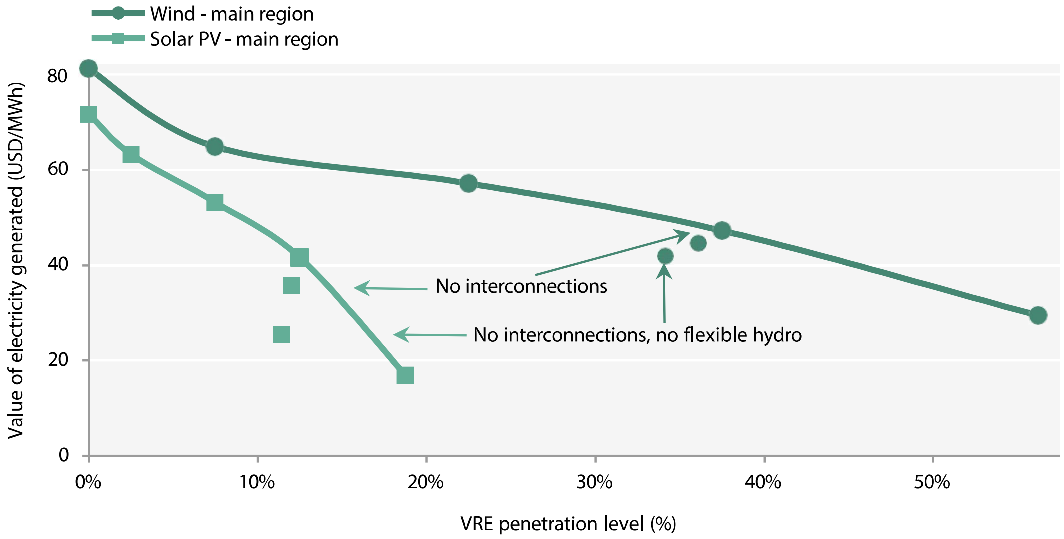
- **Connection costs** consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid. They can be significant especially if distant resources have to be connected, as can be the case for offshore wind, or if the technology has more stringent connection requirements (as is the case for nuclear power). Connection costs are sometimes included in the LCOE plant-level costs. In the present study, connection costs are not included in capital investment costs and are thus accounted for separately.

In addition to plant-level generation costs, these four specific cost categories that accrue at the system, or grid-level (which is why they are also sometimes referred to as grid-level system costs), cover the vast majority of the total costs for a given electricity system. They are reported in this study as the costs of different generation mixes capable of attaining net zero emissions in 2050. However, these categories do not cover all costs that distinguish one technology from another. For instance, the heavy rotating mass of thermal power plants with large steam turbines provides inertia, a critical service that facilitates maintaining a stable frequency on the transmission and distribution networks. In VRE dominated systems, it is possible to work with advanced electronics to create synthetic inertia, at an added, yet usually comparatively modest, cost.

Possibly more important, but very difficult to quantify, is the technical wear and tear that systems with high shares of VRE impose on dispatchable capacity, which is now required to ramp up and down far more often. This is a real issue in systems with significant gas- and coal-fired power generation as well as countries such as Belgium, France or Germany where nuclear power plants engage in load-following. The latter is not the case for Switzerland. Overall, the issue of wear and tear due to increased ramps is probably less of an issue in Switzerland than in other countries since, in particular, pump hydro storage facilities are specifically laid out for frequent ramping, which is the basis of their business model.

Profile, balancing, grid and connection costs thus cover the relevant cost drivers of the Swiss electricity system in addition to plant-level costs. Nevertheless, these four cost categories are not quite of the same nature, both in terms of their methodological grounding and in terms of their economic interpretation. Profile costs are to some extent the original system costs or at least without them, the topic would have a much lower policy relevance. While their precise level depends on relative costs, flexibility resources and the structure of demand, they are also by far the most important element of system costs. Methodologically, the profile costs of different energy systems are fully integrated in the results of the NEA's POSY model optimising investment and dispatch for different generation mixes. In the context of the current report, it has, however, not been considered useful to parcel out explicitly profile costs from the overall system costs. This is because profile costs can only be established in comparison to a least-cost reference scenario. However, the current report, unlike the NEA (2019) and (2012) studies, does not posit one least-cost scenario without any capacity constraints, but works instead with different scenarios that all pre-define large amounts of the capacity mix as brownfield, in particular hydro, and for the LTO scenarios, nuclear energy. In addition, in the case of Switzerland with its exceptionally high level of interconnections, trade effects have a large impact on the overall costs of the different scenarios. Increasing the share of VRE thus not only directly impacts domestic requirement for back-up and flexibility but also indirectly impacts the ability to benefit from electricity trading. For these two reasons, differing brownfield assumptions and trade effects the meaning of an explicit profile cost assigned to a MWh of VRE production based on a comparison of two equilibria would not be entirely clear in the present case.

Figure 4.1. **The market value of electricity produced by wind and solar PV declines in function of their share in the electricity mix**



Source: NEA, 2019.

Economically, profile costs can be an intellectually challenging phenomenon. For instance, a competitive electricity sector with free exit and entry and with no exogenously set elements of the capacity mix, there would not be any economically relevant profile costs – even in the presence of variable renewables such as wind and solar PV. While profile costs as such, increased back-up costs due to variability of VRE generation, would still exist, competition would ensure that VRE capacity is such that the increased system costs are exactly off-set by the cost advantage of VRE in terms of LCOE. In other words, profile costs are present and yet the system is at its optimal least-cost level.

This is due to the fact that in such a theoretical electricity sector, the average price or value of the electricity produced by VREs would declines as their share increases (see Figure 4.1). This induces investors to limit VRE investment at the economically optimal point when the lower capital and LCOE costs of VRE are offset by their declining value. The declining value of VRE and profile costs are two sides of the exact same coin. In an ideal competitive system, profit maximisation and competition between individual generators thus will ensure the level of VRE that is optimal at the system level. In reality, of course, exit and entry in electricity systems is not free and many countries gear their electricity systems towards absorbing *more* than the economically optimal share of VRE. In these cases, the profile costs not only highlight the need for back-up, but also impose an additional economic cost on the overall system

Table 4.2. **System costs and profile costs in the POSY Model (Autarchy case)**

Scenario	Solar PV production (TWh)	System costs (USD billion)	Added costs (USD billion)	Added costs (USD/MWh$_{PV}$)	Avg. costs Solar PV (USD/MWh)	Avg. price Solar PV (USD/MWh)
LTO	21.60	2.82	0	0	85.17	82.31
VRE only	37.32	5.41	2.59	69.4	85.15	78.21
New nuclear 3.2 GW	14.33	2.86	0.04	2.8	85.17	89.01
New nuclear 1.6 GW	25.28	3.87	1.05	41.5	85.16	81.75
New gas	31.26	4.54	1.72	55.0	85.16	86.23

So profile costs continue to hold great meaning for ranking different equilibria as soon as the economically optimal point of VRE deployment is surpassed due to policy-imposed objectives of high renewable targets. This is already the case in most European countries, and is certainly the case in all the scenarios presented as possible policy options for Switzerland. This can be shown, for instance, regarding the LTO and the VRE only scenarios in autarchy, which abstracts from trade effects that would add a layer of complexity, and only solar PV for simplicity. When substituting dispatchable nuclear generation with VRE, total systems costs increase. This is partly an effect of the lower LCOE costs of nuclear LTO. However, that the share of VRE is uneconomically high can be seen by comparing average VRE costs with average VRE prices generated in the electricity market during the hours when VRE produce, which is at USD 78.21 per MWh, lower than its average cost of 85.15. This is an indicator of the profile costs imposed on the system due to an uneconomically high share of solar PV capacity given the assumption of a fixed capital cost of USD 1 000 per kW for solar PV.

The interplay between LCOE generation costs and system costs can also be observed in other scenarios. For the scenario with 3.2 GW of nuclear baseload, the POSY model calculates total costs comparable to those of the least-cost LTO case. However, the large amount of dispatchable nuclear capacity reduces the need for solar PV generation, whose average costs are now even above its average price. Profile costs are therefore lower. At the same time, the relatively high capital costs of new nuclear baseload limit the impact of this reduction and imply the LTO scenario as the least-cost scenario. VRE profile costs are again higher in the scenario with only 1.6 GW of nuclear baseload and a higher amount of solar PV generation.

Contrary to the 2019 NEA study, systematically calculating profile costs in a more precise manner would not generate useable information, given that different scenarios presented for attaining Switzerland's net zero target in 2050 do not only differ in terms of the share of VRE, but also in terms of different dispatchable options available. The LTO scenario thus neither allows for nuclear new build nor gas as an option and vice versa. While this does not make for generally comparable profile cost calculations, the choice of scenarios that differ in more ways than their share of VRE is, of course, justified by their relevance for current and future Swiss energy policy debates. In other words, the system cost analysis of electricity systems very much depends on the policy question one is trying to answer. Between an analytical view of the system costs of VRE at different shares in the generation mix and the relevance of different scenarios for Switzerland's low-carbon future, this report has opted for the latter.

Table 4.3. **Estimates for grid and balancing costs (USD/MWh$_{VRE}$)**

	Penetration level (%)	Grid costs	Balancing costs
Wind	<10%	3	1.0
	10% to 30%	5	2.0
	30% to 50%	8	4.0
	50% to 75%	11	6.0
Solar PV	<10%	1	0.5
	10% to 30%	2	1.0
	30% to 50%	4	1.0
	50% to 75%	7	1.5

Source: Adapted from (NEA, 2019: 142).

The other components of system costs, balancing, grid and connection costs are (a) an order of magnitude smaller than profile costs, (b) the result of an entirely different methodology and (c) of a more intuitive nature. They do not result from operating the POSY model. The latter is working with an hourly resolution and a single locational node for Switzerland, thus allowing for neither the calculation of balancing costs, that accrue at a sub-hourly level, nor network effects. However, models with more differentiated temporal or spatial representation obtaining meaningful data on balancing costs, grid costs, composed of the costs for grid extension and grid reinforcement, and connection costs, require trade-offs in another dimension – for instance, electricity trade or technical constraints. The 10-Year Network Development (TYNDP) prepared by the European Network of Transport System Operators for Electricity (ENTSO-E) provides a glimpse into the vastness of the effort required to get a meaningful estimate of future network costs for the most likely medium-run scenarios, let alone for a set of five significantly distinct net zero scenarios by 2050 (ENTSO-E, 2022).

As in most other exercises of this nature, this report also bases its estimates of balancing, grid and connection costs on a review of the existing scientific literature in this field. A thorough literature review of this kind was operated at the occasion of the preparation of NEA (2019). Given that no more recent data specific to Switzerland was available for all technologies, data from the 2019 study, well accepted by a community of experts, was additionally used as the primary input in this report (see Tables 4.2 and 4.3). The 2019 data was nevertheless adapted and updated in the light of the specific VRE penetration levels analysed, and the evolution of the capital investment costs of different power generation technologies.[1]

Table 4.4. **Connection costs (USD/MW/year, 5% of capital investment costs)**

OCGT	1 919
CCGT	2 911
Nuclear new build	12 382
Wind	5 243
Solar PV	3 548
Hydro run-of-the-river	7 685
Hydro reservoir	7 930
Hydro pump storage	6 792
Battery	2 332

Source: Adapted from NEA (2019: 141); connection costs for nuclear LTO and hydroelectric installation are part of brownfield costs; connection costs for demand response (DR) are assumed to be included in the smart metering infrastructure that can reasonably be assumed for 2050 but whose costs lie outside the perimeter of this study.

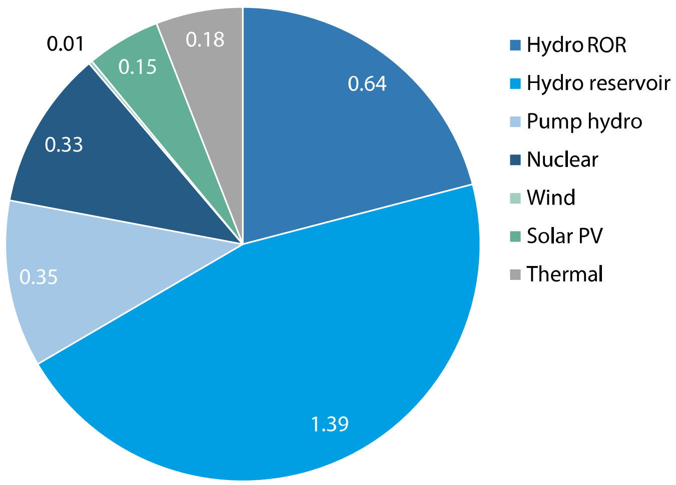
The nature of balancing grid and connection costs, however, is easily understood. They are either classic production costs or externalities, i.e. additional costs either absorbed by the operators themselves, for instance, through buying insurance in balancing markets or paying for connection, or socialised through the network operator as is typically the case for grid costs. The latter is the case in Europe. Certain electricity systems, such as the PJM in the North-Eastern United States have nodal pricing, which to some extent also parcel out network development costs to the generators. Contrary to profile costs, the level of the optimal share of VRE has no bearing on the interpretation of balancing, grid, and connection costs. They always constitute net additions to the costs of using certain technologies.

1. On the nature of the data stemming from the literature review, NEA (2019) comments: "Most of the reported data concern low or mid-penetration levels (generally from a few percent up to 30%-40% of wind or solar PV penetration). The data used for a penetration levels of 10%, 30% and 50% represent the (lower-end) spectrum of results found in the literature. The additional costs for T&D networks to accommodate significant amounts of decentralised and variable renewable energies such as wind and solar PV requires further systematic study" (NEA, 2019: 141).

Greenfield and brownfield costs

As discussed above, system cost analysis includes a number of cost categories other than traditional LCOE, which provides useful but partial information. Minimising the costs of an energy system subject to the constraint of satisfying a given demand at all times, requires designing systems in which technologies with different characteristics and cost structures work together in an optimised manner. Such characteristics not only concern the absolute and relative levels of fixed and variable costs, but also qualities such as dispatchability, seasonality, intermittency, and storability or flexibility over different time frames. Even finer characteristics would refer to ramp rates or necessary downtimes for repairs or refuelling. As explored in Chapter 3, the great advantage of mixed-integer linear programming (MILP) models is that they can provide optimised generation mixes, considering both investment and dispatch, including both a number of technical constraints and competing policy choices that set constraints of a different nature.

Figure 4.2. **Annual brownfield investment costs in 2019 (USD billion)**



Notes: Based on capacities and costs according to Tables 3.2 and 3.6.

This is where the specificity of the cost notions employed in this report comes into play. For instance, to make an informed decision in 2022 between two policy scenarios that would both achieve net zero carbon emissions in 2050, would it be important to know the costs of construction of a hydroelectric reservoir or a nuclear power plant in the 1980s, or even that of a wind turbine or a solar PV installation in 2018? Given that the model is validated on the year 2019, all capacity implemented in 2019 and prior is assumed to be still operating in 2050, and is indeed set exogenously in the current model. The costs for such exogenously set capacity investment are referred to as brownfield costs. Figure 4.2 provides the repartition of the different brownfield costs for capacity installed already in 2019.

The model thus only ever optimises over that part of the electricity system that is not previously set and is thus endogenously determined. The costs of such post-2019 investments are referred to as “greenfield costs”. Of course, all variable costs for all capacity or flexibility options, including demand response, are also part of greenfield costs.

Given that the aim of this report is to assess the costs of energy policy choices in the present or the near future, it concentrates on greenfield costs. If not indicated otherwise, all system cost figures refer to greenfield costs, as these are the policy-relevant costs going forward from the base year 2019. It therefore also adheres to the fundamental economic maxim to “never consider sunk costs”. Brownfield costs are, by definition, identical in all scenarios presented in this report.

Economic and physical system costs

The third methodological dimension to be considered in the assessment of the system costs of different scenarios concerns the relationship between the cost incurred by the Swiss operators of the domestic generation mix and the costs or benefits generated by cross-border electricity trade. Switzerland is a key participant in European electricity trading and is intensely affected by these exchanges by any measure, whether considering the amount of imports and exports compared to total electricity demand or the relationship between peak demand and interconnection capacity. Strategically placed at the heart of Europe between high-cost Italy, low-cost France and the large amount of renewable resources of Germany with intermittent production, Switzerland has a vital function as a platform for the arbitrage of electricity prices. Its hydroelectric reservoirs and pump storage installations provide it with the flexible production capacity to take full advantage of this situation.

Electricity trading thus matters to Switzerland and its economic well-being. The ability to import when prices are low and to export when prices are high does not only benefit producers but also consumers, who benefit from lower domestic prices and higher utilisation rates of Swiss installations. To derive meaningful cost comparisons of different scenarios, the net benefits derived from electricity trading therefore need to be taken into account. The relevant cost figures in this report are the economic costs defined as follows:

Economic system costs	=	Physical system costs (Costs of Swiss domestic production)
		– Net trade revenues (Export revenues minus import costs).

If net trade revenues are positive, which is the case in most scenarios, the economic system costs are thus smaller than the physical system costs. In the rare case that net trade revenues are negative, i.e. the costs of imports are higher than export revenues, they must be added to the costs of domestic production.

It is highly instructive in Chapter 4 to see that certain scenarios can have higher physical system costs but also higher net trade revenues to arrive at lower overall economic system costs compared to other scenarios with lower physical system costs but also lower net trade revenues. Overall, it can be said that adding dispatchable capacity such as nuclear energy to the Swiss energy system improves net trade revenues and hence lowers economic system costs. Adding variable capacity such as wind and solar PV, whose production will be determined by the weather rather than by prices, will decrease net trade revenues and thus increase economic system costs.

Needless to say, in the autarchy scenarios economic system costs and physical system costs are identical. It must, however, also be said that both cost categories will be considerably higher than in cases with either 100% or 50% of interconnection capacity.

The total system costs of different electricity mixes thus depend on the plant-level costs of the different available technologies as well as on their availability, dispatchability and flexibility. The latter three issues affect all energy sources and all energy systems in one way or another. However, in low-carbon energy systems, in particular net zero systems, they can easily become predominant to the extent of even overpowering the impacts of plant-level costs. In most low-carbon energy systems, two factors are particularly important in this context: first, the large shares of VRE such as wind and solar PV, and second, the vanishing share of carbon emitting natural gas, whose flexibility characteristics corresponds by and large rather well to the needs created by VRE.

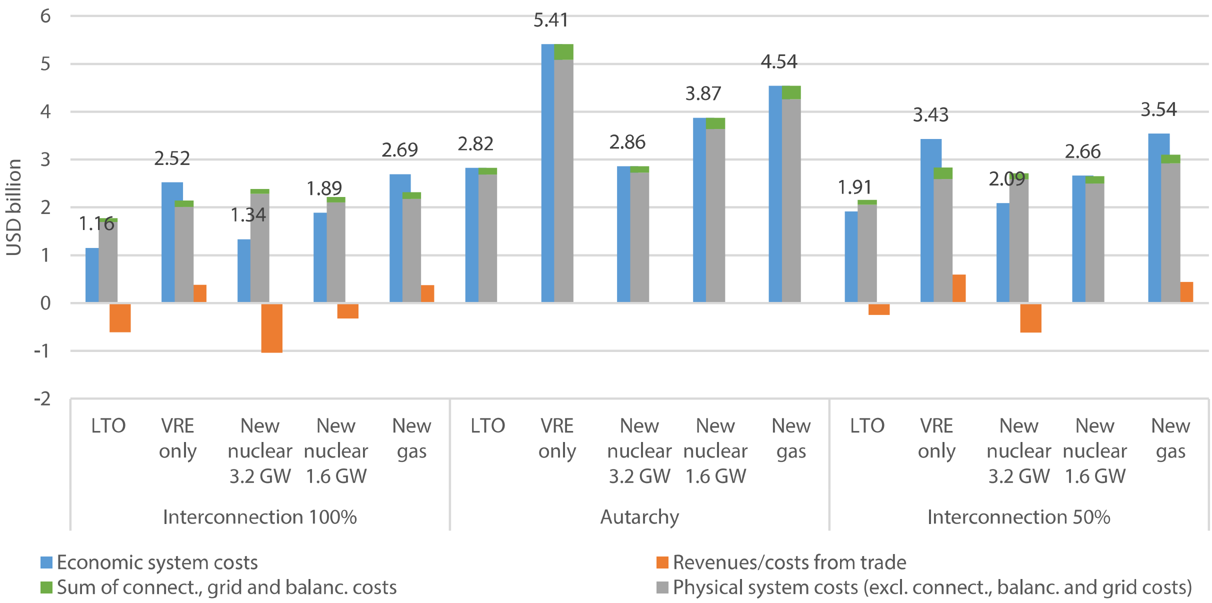
As has been well documented in studies such as NEA (2012) and NEA (2019) as well as others, large shares of VRE will create the need for dispatchable back-up capacity during hours where no energy from wind or solar PV are forthcoming. Such dispatchable back-up capacity will operate at less than economically optimal hours, sometimes only at very few hours. Since the costs of the original capacity investment need to be invested to ensure sufficient supply at all hours regardless of the number of hours it operates, this drives up the total cost of the whole system. The amount of VRE capacity in the system as well as its correlation with demand will determine the precise level of this cost increase.

4.3. Total system costs, capacity and generation in the five net zero scenarios

In the following, key results for the five scenarios, LTO, VRE only, New nuclear 3.2 GW and 1.6 GW as well as New gas, in the three constellations of electricity trade, interconnections at 100%, autarchy and interconnections at 50%, will be presented in the form of overview graphs enabling a comprehensive understanding of the main features of the different scenarios.

Figure 4.3 presents the principal cost categories composing the total system costs of the different scenarios. The physical system costs (in grey) correspond here to the domestic Swiss generation costs. Net trade revenues (in orange) appear as negative costs except in the rare situation of a trade deficit, when they obviously become additional costs. The sum of connection, grid and balancing costs are presented separately (in green). The economic system costs (in blue) correspond to the sum of physical system costs including costs from connection, balancing and grid costs (in green) and net trade revenues, so they are mainly lower than the physical system costs due to positive trade revenues in most scenarios. Profile costs are implicitly taken into account in both the physical and economic system costs. Finally, economic system costs are indicated as a numerical value for each of the 15 scenarios.

Figure 4.3. **Total system costs of the five net zero scenarios under different electricity trade constellations (USD billion)**



Note: Economic system costs in blue are equal to physical system costs in grey *plus* the sum of connection, grid and balancing costs in green *minus* trade revenues in orange. The values of economic system costs are displayed on top of each bar chart and can also be referred as the total system costs.

The first observation is that the most cost-effective option to reach Switzerland's net zero objective in 2050 is to continue operating its two youngest nuclear power plants, KKG and KKL, as well as to maintain the capacity of the interconnections for electricity trading with its neighbours at current levels. LTO of 2.2 GW of nuclear capacity would also be the most cost-effective option in the trade constellations of autarchy or with reduced interconnections capacity. The LTO scenario has, in particular, lower economic costs than the VRE only scenario, less than half indeed in the trade constellation of keeping interconnection capacity at current levels.

The second observation, regardless of which electricity generation mix Switzerland decides to adopt, is that it is always economically more efficient to maintain interconnection capacity at current levels, rather than to reduce them or even to close them entirely in order to operate the Swiss electricity system in autarchy. The argument to keep Switzerland's rightly prized hydroelectric resources, in particular the flexibility of its pump hydro stations, for domestic use, appears a fallacy. While these resources would be employed to their maximum extent in the autarchy scenarios, they would serve primarily to balance the impacts of the very last MWh of solar and wind that generate little economic value. In autarchy, Switzerland would lose twice. First, Swiss generators would lose the revenues from exporting flexible generation for higher-value uses in neighbouring countries. Second, Swiss consumers would forego the considerable benefit of having open interconnections as an additional flexibility resource. While Swiss domestic flexibility resources are strong, they are not infinite. Logically, the scenario that benefits most from electricity trading is the VRE only scenario that requires enormous amounts of flexibility resources (for a detailed discussion of flexibility provision in the different scenarios, see below).

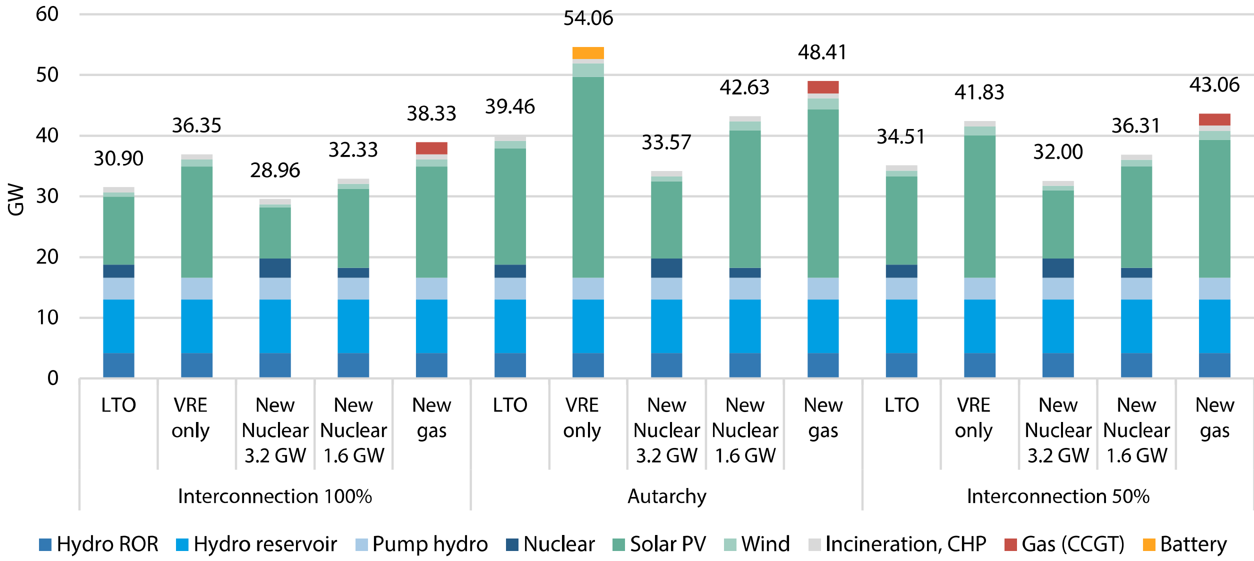
The rank ordering of the three trade constellations is indeed robust across all scenarios and across a variety of assumptions; keeping interconnection capacities at current levels is the economically first best option. Reducing interconnections to 50% of their current capacity, but keeping them open for the highest-value trades, is the second best option. Autarchy is, by some distance, the least-best option.

The third observation is that other than the long-term operation of existing power plants, building new nuclear power plants would be the alternative scenario with the lowest economic costs to achieve net zero. In all three trade constellations, building and operating two new nuclear power plants with 3.2 GW would be more cost-effective than only a single new 1.6 GW plant. The relative advantage is particularly relevant in the two scenarios with electricity trading. There are trade-offs involved here. On the one hand, building one or two new nuclear power plants involves significant additional costs due to the fixed investment for one or two new nuclear power plants that need to incurred. On the other hand, the benefits of the availability of large amounts of around-the-clock low-carbon electricity generation both for domestic consumption and, in particular, for exports provides significant economic benefits.

The fourth observation is that the VRE only scenario is economically preferable to the New gas scenario as long as interconnections for electricity stay open, whether at current or at reduced capacity levels. The New gas scenario, however, has lower costs under autarchy. The reasons are quite straightforward. The high carbon price of USD 100 per tonne of CO_2 makes gas uneconomical as long as less costly alternatives such as imports are available. However, in the absence of such alternatives the possibility to have some flexible gas-fired capacity available is attractive compared with the high costs of flexibility provision in a VRE only scenario.

Moving on from considerations of total system costs to considerations of capacity, the insights produced by the POSY model and reproduced in Figure 4.4 are quite straightforward. To some extent, the scenarios themselves are defined by their capacity mix – LTO, VRE, New nuclear, New gas – and the model optimises only over the unconstrained remainder. The fact that Switzerland's considerable hydroelectric resources, as well as its existing thermal resources, are considered historically given brownfield capacity, further reduces surprises in this dimension. Nevertheless, two observations apply. First, quite logically, high shares of solar PV and wind in the generation mix, see also Figure 4.5 below, over-proportionally push capacity requirements due the comparatively low load factors of VRE. This makes land use an intrinsically important issue in the Swiss energy policy debate. This debate is more complex than it might seem at first sight. As an alpine country that values its pristine vistas, with a sizeable tourism industry, there is broad consensus that wind energy will be largely confined to the lowlands along the Rhine river and around lakes in Northern Switzerland. The Swiss VRE strategy was always meant to rely predominantly on solar energy. However, this poses the question of what kind of solar energy. This is a pertinent question as sizeable amounts of new VRE capacity are a part of all scenarios.

Figure 4.4. **Capacity mix of the five *net zero* scenarios under different electricity trade constellations (GW)**

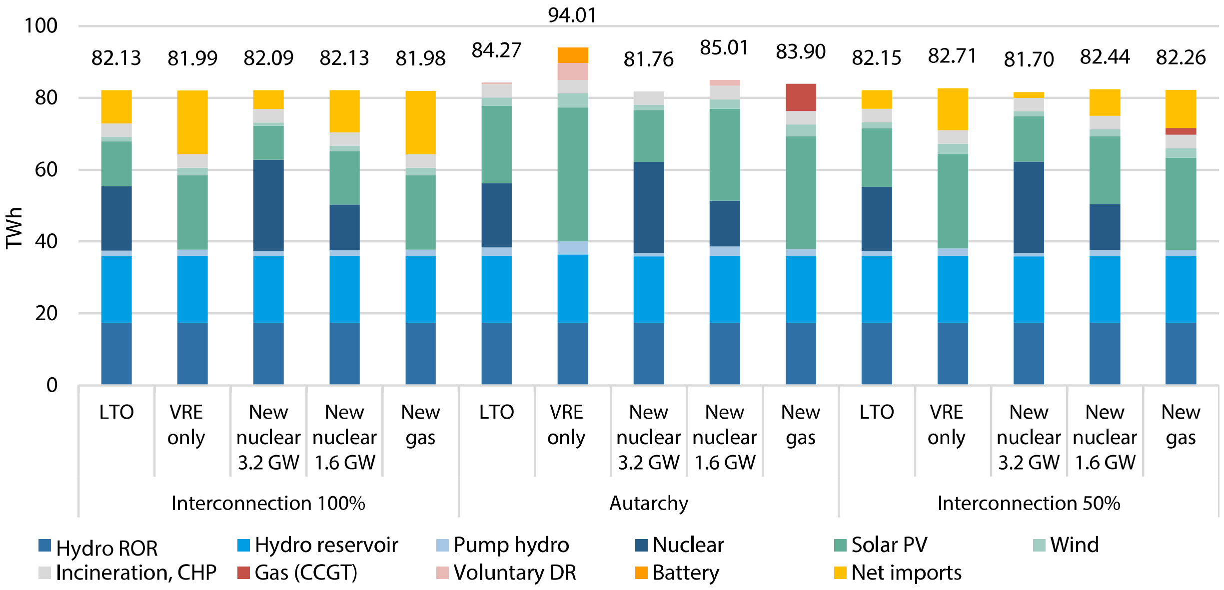


Rooftop solar on residential buildings has siting requirements that are somewhat different from those of commercial solar PV generation, using agricultural hangars or industrial buildings and very different requirements from those of utility-scale solar parks. The latter would presumably face similar strictures as wind turbines. As it happens, utility-scale solar is, however, also the least costly and economically most profitable option of solar power. With costs of USD 1 000 per kW for solar PV, this report has taken an average value close the costs of commercial solar PV capacity indicated in IEA/NEA (2020). As a first orientation, this might suffice. However, in the future, as the energy policy debate evolves, the question of which forms of solar PV, their siting requirements, and costs Switzerland wishes to see in its advancement towards net zero emissions by 2050, is of great relevance.

The second observation is that in the autarchy scenario, the absence of interconnection capacity as a flexibility resource requires the adoption of new flexibility capacity. This additional capacity to existing domestic flexibility resources, hydro reservoirs, and pump hydro installations, takes the form of voluntary demand response, i.e. a voluntary reduction of demand that is remunerated in the market, and batteries. For the former, this report assumes load shedding at a cost of USD 300 per MWh and for the latter lithium-ion batteries at a cost of USD 484 per kW, to which one must add the variable costs of the electricity required for charging. While these are valid options with few externalities beyond their economic costs, their adoption nevertheless indicates the stress that the Swiss electricity system would be operating under in the autarchy scenarios.

The insights drawn from the capacity mixes of the five scenarios in Figure 4.4 are complemented by those derived from considering the generation mixes in Figure 4.5. The first observation regards the important role played by electricity imports. In all five net zero scenarios, Switzerland imports more physical electric energy than its exports, as long as interconnections stay open. Net imports are highest in the VRE only scenario, which is quite intuitive as in this case the flexibility needs are greatest. Net imports are lowest in the LTO and New Nuclear scenarios with their constant round-the-clock generation of baseload electricity. In all scenarios, both imports and exports decrease when interconnection capacity decreases to 50% of current levels. While this report has not explicitly tested the hypothesis, one can safely say that with even larger interconnections, net imports may have a tendency to increase as long as the price dynamics in the neighbouring countries remain similar. Coherent energy policy-making would thus associate a VRE only strategy with a particularly strong push for open interconnections or even an increase in the level of current interconnection capacity.

Figure 4.5. **Generation mix of the five *net zero* scenarios under different electricity trade constellations (gross production, TWh)***

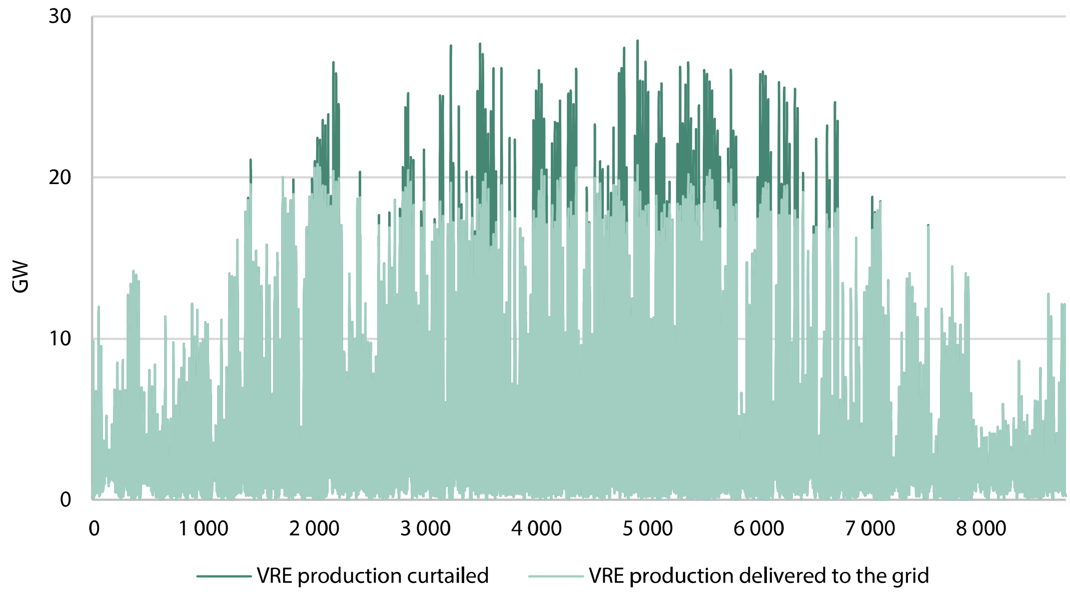


* To allow for a comparison of all components of the system, Figure 4.5 is based on numbers for gross production, which include the gross contribution of batteries and demand response. In reality, batteries have an annual net contribution that is zero or close to zero as every TWh released for consumption will have consumed an equivalent amount during charging including a top-up to account for roundtrip efficiency losses. Demand response actually corresponds to a reduction in demand. In the VRE only scenario in autarchy somewhat less final energy services will thus be consumed than in the other scenarios. In a very loose manner, one could say that the gross TWh figures in the graph above correspond to the totality of the effort supplied by the system to have supply meet energy services demand.

At this point, the important distinction between physical electricity flows and commercial electricity flows, which is particularly important in the present case, needs to be reaffirmed. Today, Switzerland already imports more physical electricity than it exports. The POSY scenarios indicate that this is unlikely to change by 2050 under a net zero commitment. Then, as now, however, Switzerland also has a systematically positive commercial balance in electricity trading, i.e. it earns more revenue exporting than what it pays foreign suppliers when importing. This is where Swiss domestic flexibility resources interact in a most beneficial manner with the flexibility provided by large interconnection capacities: its hydro reservoirs and pump storage installations enable Switzerland to import cheaply and export dearly, earning substantial amounts of trade revenues in the process.

A second observation is that the high VRE shares in the capacity mix that were identified above do not translate in equal proportion into shares in the generation mix. This is first and foremost due to the comparatively low technical load factors for solar PV (13%) and wind (21%) in Switzerland. Second, it is due to the variability and autocorrelation of VRE, as their available capacity operates during a limited number of hours when their contribution is not necessarily of the greatest value. During some hours of the VRE only scenarios, in particular in autarchy, excess production even needs to be curtailed in order to ensure the stability of the electricity system (see Figure 4.6). In other words, not all technically possible VRE production is converted into economically useful energy. Conversely, in the case of nuclear baseload generation with its high load factors, the share in the generation mix is proportionately higher than the share in the capacity mix.

Figure 4.6. **Curtailment of the VRE production for the VRE only strategy in Autarchy (GW)**



Note: In the VRE only scenario with no interconnection, 2.8 GW (7%) of the total annual VRE production were curtailed.

A third observation is that gross production is considerably higher in the VRE only scenario in autarchy and somewhat higher in the other autarchy scenarios with the exception of the New nuclear 3.2 GW scenario. This is due to the already observed fact that the scenarios in autarchy draw much stronger on domestic flexibility resources such as pump hydro and battery storage. These resources however need to be charged during surplus hours which explains the higher gross production. Net consumption of energy services provided on the basis of electricity – light, heat, kinetic energy in industry and transport as well as hydrogen production for industrial purposes – remains the same in all scenarios (see also the discussion dedicated to flexibility provision in Section 4.5). Gross production is lowest in the New nuclear 3.2 GW scenario in autarchy, lower even than in the same scenario with fully available interconnection capacity. This is due to two reasons: the large amounts of low-carbon baseload require few flexibility resources and thus little charging. At the same time, the lack of export opportunities reduces production further. Swiss domestic demand is thus satisfied in an economical but not in the most profitable manner.

Focus on flexibility provision

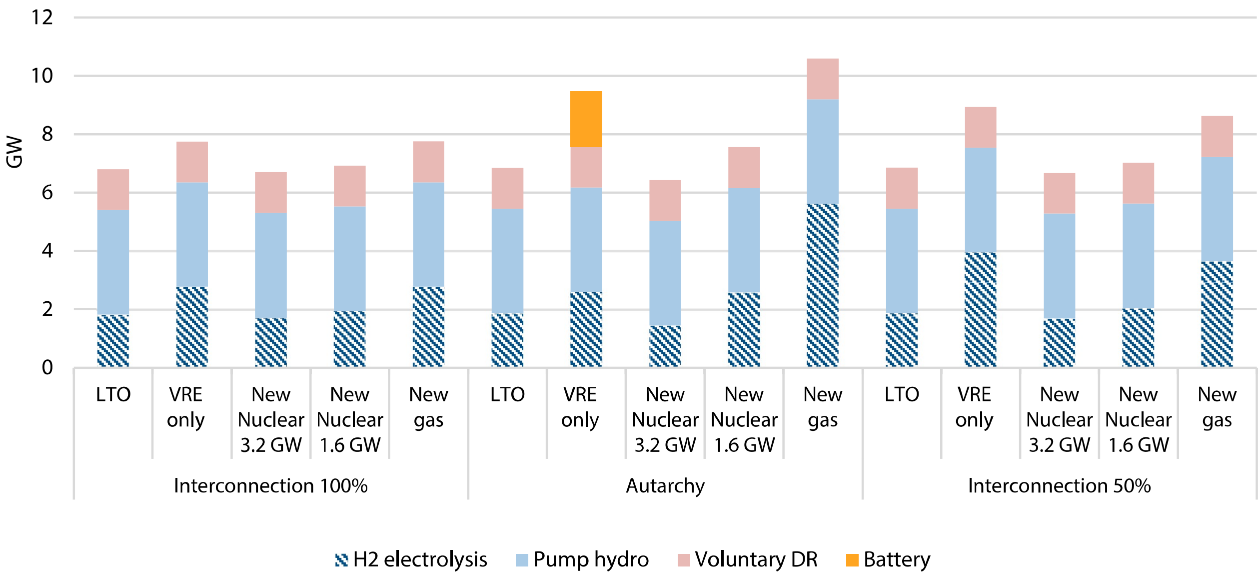
As has already become apparent, the availability and cost of different sources of flexibility is a key element in determining the technical feasibility and the overall costs of different net zero scenarios under different trade constellations. Flexibility refers in this context to the ability to provide large amounts of electricity at short notice, but not necessarily for many hours, in order to compensate for the temporary shortfall of other generating sources. Typically, flexibility is prized to complement the variability of solar PV and wind. However, outages due to technical problems or sudden demand bursts may also require activation of flexibility resources in order to maintain the balance of electricity demand and supply second by second. The latter is crucial in electricity systems, as the stability of the grid depends on this balance. Any disturbance, in the absence of sufficient flexibility resources, would lead to outages with long delays for restarting operations.

Providers of flexibility in electricity systems are characterised by two main qualities: first, the ability to react quickly to changes in the load provided by other generators whether foreseen or unforeseen and two, low fixed capital costs. The latter point is important. Since flexibility providers need to be able to generate large amount of energy for short periods of time, they usually have low load factors. Capital costs can thus be amortised only during a limited number of hours, which implies they need to be as low as possible. Instead, variable costs are less of a concern. In times of need, paying a high price for a few hours is a lesser cost than a breakdown of the grid. Finally, in a net zero scenario flexibility provision should also be carbon-free. At high implicit or explicit carbon prices, this excludes the flexibility provider of choice in many electricity systems, the open-cycle gas turbine (OCGT) whose advantage of low fixed costs are offset by low thermal efficiencies and consequently high carbon emissions per MWh.

Switzerland is fortunate to dispose of an alternative large low-carbon flexibility provider in the form of its 3.58 GW of hydro pump storage facilities, which are the bedrock of its domestic flexibility provision in all five *net zero* scenarios (see Figure 4.7). These are complemented by 1.4 GW of voluntary demand response, i.e. electricity customers willing and capable of reducing demand, against remuneration, during times of need. Four further flexibility sources merit mentioning.

First, the system can install any amount of electrochemical batteries as long as economic conditions, that is investment costs on the one hand and the average spread between the prices at times of charging and releasing on the other, allow for it. It should be noted that this relatively costly option is employed exclusively in the VRE only scenario under autarchy.

Figure 4.7. **Domestic capacity mix for flexibility provision in different *net zero* scenarios (GW)***



Note: LTO = long-term operation; VRE = variable renewable energy; DR = demand response.

* Figure 4.6 does not include capacity for interconnections that are an important additional source of flexibility. However, its contribution varies with the sum of net imports available at each hour. The latter, does not depend on the Swiss system alone but also on the demand and supply balance in neighbouring countries. The nature of the flexibility service per GW is thus somewhat different than that of domestic sources ready to be called upon even though the latter might be subject to technical constraints.

Second, many experts agree that Switzerland by 2050 will produce sizeable amounts of hydrogen for industrial purposes and residential end-uses. The POSY model thus assumes that 8 TWh of electricity will be used for the generation of hydrogen on the basis of water electrolysis with the help of proton exchange membrane (PEM) electrolysers. Even if all hydrogen is subsequently used directly as a chemical feedstock or in fuel cells without re-injection into the electricity system – for instance to drive a hydrogen-powered turbine – hydrogen production remains an important source of flexibility. While the total annual production of hydrogen is fixed, the model optimises the electrolyser capacity and the generation profile according to the conditions and needs of the electricity system. The PEM electrolysers are highly flexible and can thus be switched on hourly during times of excess supply and switched off during times of high demand.

Adding 8 TWh of hydrogen production will increase overall generation capacity but will decrease the draw on alternative flexibility resources. This is because hydrogen production is a form of demand that complements autonomous electricity services demand and flexibility resources. Hydrogen production will take place only during hours when energy services demand and the costs of generation are low. During higher value hours, hydrogen production will be idle and thus release precious capacity. It thus fulfils a function similar to voluntary demand response, with the difference that its costs are not the fixed set costs of demand response but the variable costs of the marginal technology at any given hour when no higher value uses, especially in terms of exports are available.

The flexibility contribution of the electrolysers can be identified very clearly in Figure 4.7. The scenarios with higher flexibility needs, typically the VRE only scenarios, have higher electrolyser capacities than the others. This is due to the fact that system optimisation will ensure that larger flexible capacities are operated over fewer hours to produce the 8 TWh worth of hydrogen. There is thus a trade-off between the higher fixed costs of the electrolysers and their flexibility contribution. In the VRE only scenarios, the latter is sufficiently prized to warrant additional outlays for the former.

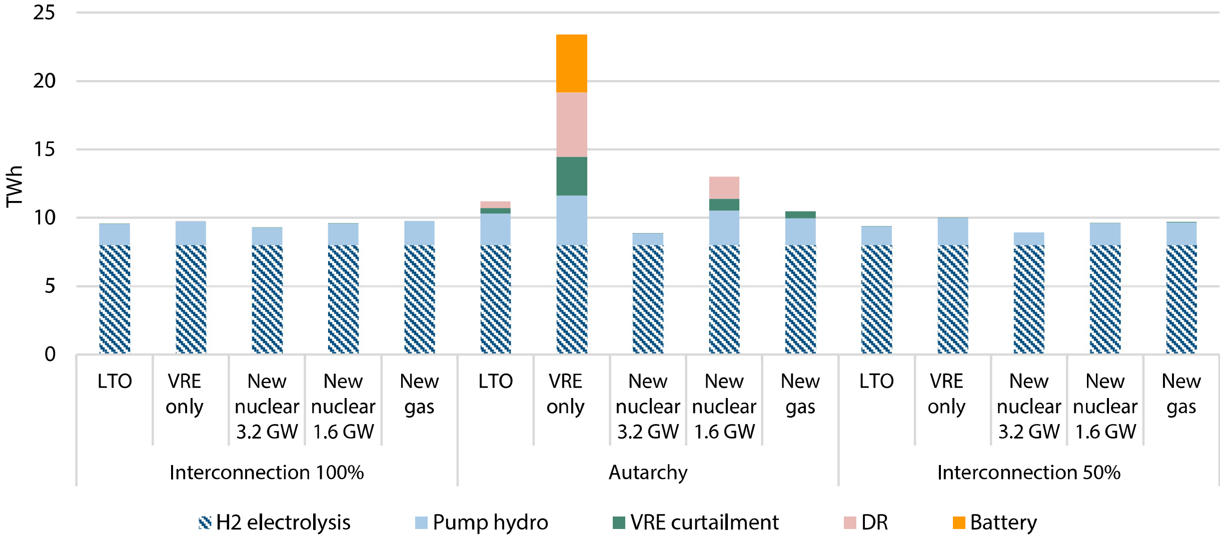
Third, more than 10 GW of interconnection are an extremely important source of flexibility that together with hydroelectric resources allows for system constellations that could not be realised in countries with less abundant flexibility resources (see the detailed discussion on the role of electricity trade in Section 4.4). Such abundant flexibility resources facilitate, in principle, the integration of large amounts of VRE such as solar PV and wind. It is noteworthy, nevertheless, that despite such favourable conditions for VRE, the net zero scenarios with large amounts of nuclear baseload have considerably lower total system costs than the VRE only scenario. This is partly the effect that flexibility provision, even if available, is not costless. Partly, it is also the effect that there is a large opportunity cost for using flexibility resources to balance domestic production rather than to use it more profitably for arbitraging prices between Switzerland's European neighbours.

Fourth, there remains a flexibility resource that does not show up in the figure of the capacity mix but only in the figure of the generation mix (see Figure 4.8). This is because it is not a standing flexibility resource but a form of generation that must be reduced during hours of excess generation. This is the curtailment of VRE generation, i.e. the temporary disconnection of solar PV or wind capacities from the grid. Technically, of course, any generator can be disconnected temporarily from the grid, so this is not a feature peculiar to wind and solar PV. The peculiarity of VRE is that the fact that its production is concentrated during a relatively limited number of hours, especially in the case of solar PV during the hours around midday, large amount of VRE capacity produce spikes than can no longer absorbed by consumers – even including the charging demand from flexibility providers such as pump hydro, batteries, demand response or hydrogen production. Unsurprisingly, in the Swiss context curtailment is a phenomenon confined to the autarchy case. In the cases with 100% or 50% of current levels of interconnection capacity, low-cost VRE generation from Swiss solar PV installations can always be exported to neighbouring countries. Curtailment constitutes an economic loss as potential production remains unused and the capital costs of VRE are amortised over fewer hours. It is thus part of the system costs of systems with high shares of VRE.

In a competitive electricity market with free exit and entry, curtailment, just as the auto-correlation effect of lower average prices, is taken into account by the operators of VRE capacity, who will invest up to the point where costs and revenues are equalised. In such systems, curtailment will be limited to a few extreme hours. Considerable amounts of curtailment only arise in systems where VRE capacity is subsidised, e.g. through guaranteed feed-in tariffs, or where no alternatives are available such as in the Swiss VRE only scenario. Switzerland's high flexibility resources can postpone that moment in the trade constellations with open borders but no longer in the autarchy cases.

The POSY results thus show the crucial role of flexibility provision in the context of advancing Switzerland's ambition to realise net zero carbon emissions by 2050. Future energy policy debates must thus not only answer the question of which low-carbon technologies other than hydro will provide the bulk of Switzerland's electricity needs under different scenarios, but also which technological and market design options are the most apt to provide the large amounts of flexibility that will be required in all scenarios.

Figure 4.8. **Load contribution of flexibility providers in different scenarios (TWh)**



Note: LTO = long-term operation; VRE = variable renewable energy; DR = demand response.

4.4. Trade, generation structures and price structures in the five net zero scenarios

Beyond the overview results of the five scenarios, LTO, VRE only, New nuclear 3.2 GW, New nuclear 1.6 GW and New gas, in the three electricity trade constellations, 100% of current interconnection capacity, 50% of current interconnection capacity and autarchy, the results of the POSY permit a wide range of detailed additional analyses. In the following section the focus will be on the three particular aspects of electricity trade, both physical exchanges and commercial revenues, load curves and residual load curves, i.e. the interplay between demand and supply and the structure of prices.

Focus on trade

Regarding electricity trade, it is necessary to recall the very level of interconnection capacity that Switzerland maintains with its neighbours Austria, France, Germany and Italy. Table 4.5 provides an overview. Considering the Swiss peak demand of 9.7 GW in 2019 and its domestic generation capacity of 22 GW, the total import capacity of 8.9 GW and the total export capacity of 11.3 GW are far above the target of 15% generation capacity that the EU specifies for its member countries. Unsurprisingly, electricity trade plays an enormously important role in the Swiss electricity system. As already indicated, this is due to the economically valuable complementarities between the electricity systems of all five countries, with Switzerland at the centre, thus making the most of its flexible hydropower resources.

Table 4.5. **Interconnection capacity between Switzerland and its neighbours (GW)**

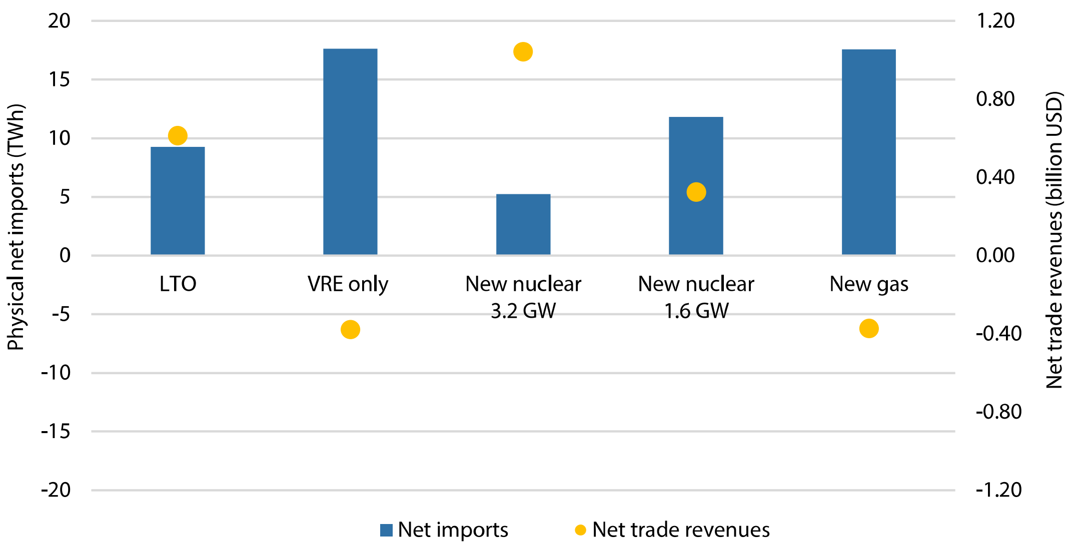
Capacity for electricity imports		Capacity for electricity exports	
AUT → CH	1.2	**CH → AUT**	1.2
DE → CH	2.7	**CH → DE**	4.6
FR → CH	3.15	**CH → FR**	1.3
IT → CH	1.9	**CH → IT**	4.2
Total	8.9	**Total**	11.3

Note: Differences between import and export capacity result from differences in the capability of the internal electricity transport grids in the respective countries to absorb the full capacity of the interconnection flows. In principle, an interconnection cable can be used in both directions.

Source: JASM platform (SCCER, 2022) based on ENTSO-E (2018).

In order to understand fully the role of electricity trading in Switzerland, one needs to be aware of the distinction between the flows of electric energy as a physical quantity and the concomitant financial flows. Switzerland was a net electricity importer in 2019 and imported 6.26 TWh of electricity more than it exported, roughly 10% of total Swiss demand. In the scenarios with open interconnections, Imports thus always cover a significant portion of Switzerland's domestic electricity needs. This is unlikely to change in the future. In a trade constellation that maintains current levels of interconnection capacity, all five net zero scenarios foresee sizeable amounts of physical electricity also continued to be imported in 2050. The highest amounts will be required in the VRE only scenario and the New gas scenario (see Figure 4.9), while the least imports will be required in the scenario with the largest amount of dispatchable baseload capacity, the New nuclear 3.2 GW scenario. In the autarchy secnarios, of course, the energy provided by importas wil have to be provided, at considerable additional costs, by domestic resources (see Figure 4.3).

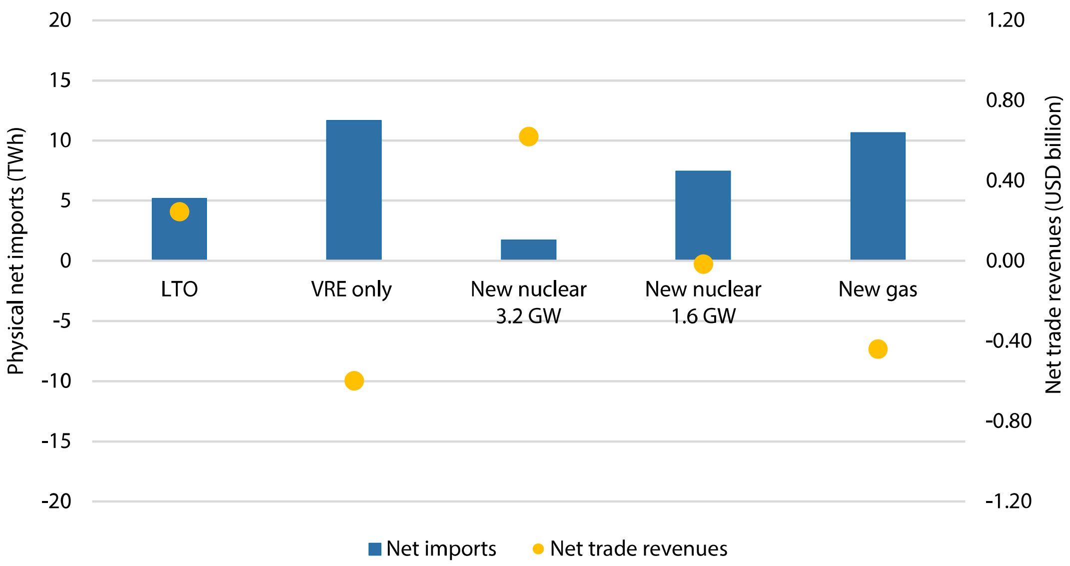
Figure 4.9. **Physical net imports and net trade revenues in the five scenarios at 100% of current interconnection capacity (TWh and USD billion)**



Despite the fact that all scenarios require physical imports, several of them earn positive revenues from trading. In other words, the ability to take advantage of the flexible Swiss resources allows generators to earn revenues on electricity exports that exceed the costs of electricity imports. Typically, a pump hydro station will buy electricity at night or at the times of high VRE production in Europe when prices are low and sell it during times of peak demand, frequently the early evening hours when industrial, commercial, and residential uses all overlap. Hydro reservoirs will complement this by also selling electricity at the most favourable hours. However, in order to use flexible hydroelectric resources in electricity trade, it must be assured that they are not committed to covering domestic demand at all times. This again where the availability of large amounts of domestic baseload power comes in. The higher the domestic baseload capacity, which in a net zero scenario is necessarily nuclear power capacity as a USD 100 per tCO_2 carbon price simply makes gas uneconomical, the higher are trade revenues. The New nuclear 3.2 GW scenario will thus earn more trade revenues than the LTO scenario with 2.2 GW of nuclear power capacity, which in return earns more than the New nuclear energy 1.6 GW scenario. In the VRE only and the New gas scenario, import costs will be higher than export revenues.

The overall tendency of the results for the trade constellation with 100% of current interconnection capacity is confirmed in the case of a constellation with 50% of current interconnection capacity (see Figure 4.10). Unsurprisingly, both physical and financial flows decrease with reduced interconnection capacity. In all five scenarios, the benefits from trading would decrease. Only the two scenarios with the highest capacity of nuclear baseload would generate a trade surplus, while even the New nuclear 1.6 GW scenario would exhibit a slight deficit. The deficits in the VRE only and the New gas scenarios would somewhat increase.

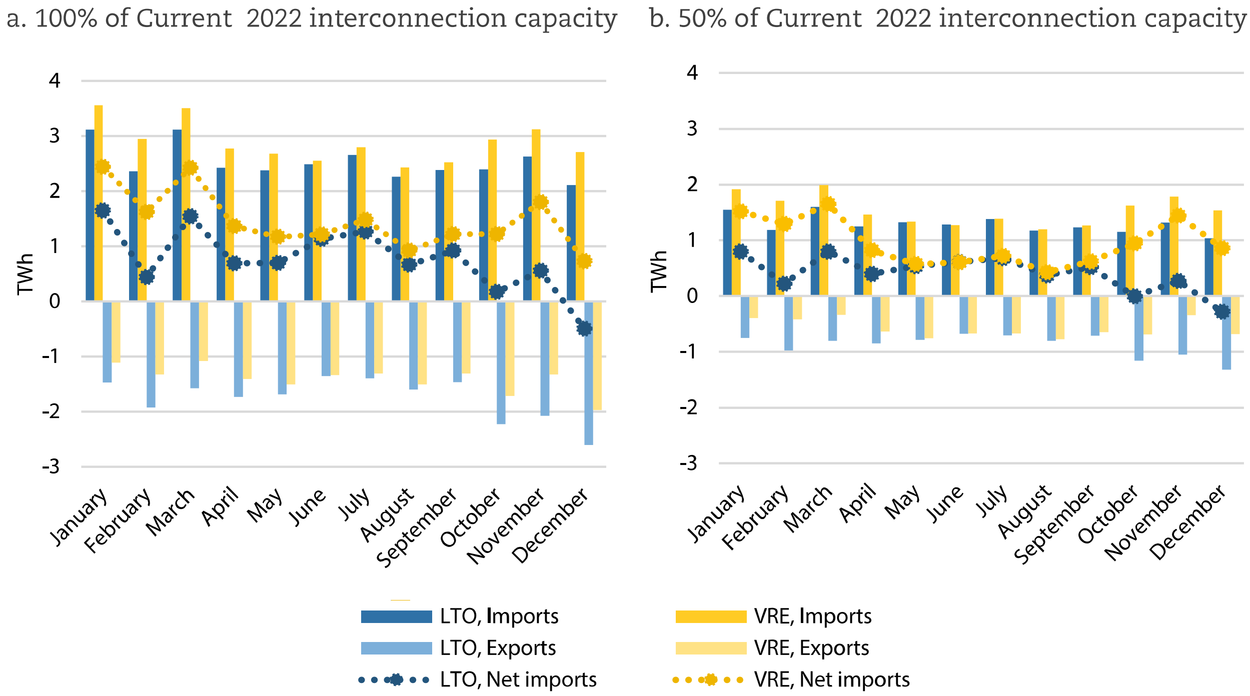
Figure 4.10. **Physical net imports and net trade revenues in the five scenarios at 50% of current interconnection capacity (TWh and USD billion)**



A trade deficit is not an economic tragedy as such. The cost of imports must be compared to their domestic opportunity costs. If the VRE only and the New gas scenarios were exceedingly cost-effective for other reasons incurring a trade deficit might be a price worth paying. However, as the results for the system cost analysis in the previous chapter have shown, the VRE only and the New gas scenarios are also overall the most expensive net zero scenarios. In such a situation, a trade deficit functions indeed as one additional cost element among others. Needless to say, in an autarchy scenario, there would exist neither physical, nor financial flows.

Another important feature of the Swiss electricity trade flows is their seasonality (see Figures 4.11a and 4.11b). Seasonality is primarily a function of the availability of hydroelectric resources, including, this time, also run-of-the-river installations. The more water becomes available in spring and early summer, the lower are net imports. This holds both for the LTO and the VRE only scenarios. The key difference, of course consistent with the annual figures, is that in each single month imports are lower and exports are higher in the LTO than in the VRE only scenarios. However, one can also discern that during summer the net import curves are closer to each other. This is due to the important solar PV capacity in the VRE only scenario, which has comparatively higher load factors during the summer months. These two tendencies are confirmed with 100% and with 50% of current interconnection capacity levels. In the 50% constellation, monthly net imports are almost identical in both scenarios as overall trade flows are reduced.

Figure 4.11. **Monthly physical imports and exports in the VRE and the LTO scenarios at 100% and at 50% of current interconnection capacity (TWh)**



Focus on load curves, residual load curves and load duration curves

Load curves indicate the demand (load) that needs to be supplied by an electricity system at every single one of the 8 760 hours of the year. Its level and structure provide a first intuitive indication of the challenges of the generation mix. In traditional electricity systems, load curves display a characteristic profile that reflects the variations of consumer demand for energy services over the day, the week, and the season. This demand is relatively inflexible and does not react very elastically to short-run price changes. Load curves are frequently complemented by residual load curves that subtract VRE generation from the total load indicating the remainder that needs to be satisfied by conventional resources. This provides useful indications for the optimal residua mix of dispatchable capacities.

As will be discussed further below, an important change in electricity systems is introduced by electric storage, which make demand far more price elastic and will tend to smooth both load curves and residual load curves. Storage providers will typically consume energy for charging during hours when energy-service demand and prices, are low, complementing traditional load profiles.

The impact of VRE such as solar PV and wind can be seen clearly both in load curves and residual load curves. Although the introduction of VRE does not directly change the load curve which indicates the demand withdrawn an any given hour, they have two structurally important effects. First, during hours with high VRE production, prices will tend to be lower, and therefore demand, in particular flexible demand for storage charging, will be higher than otherwise during hours with high VRE production. However, VRE generation will have the opposite effect on the demand for generation from dispatchable non-renewable sources such as run-of-the-river hydroelectricity, nuclear energy, or, when present, gas-fired power generation. Due to the zero short-run marginal costs of VRE, the latter, when meteorological conditions are favourable, will tend to displace dispatchable production.

Finally, the analysis of electricity systems makes frequent use of load duration curves that rank the load of each hour from the highest to the lowest. This provides a useful gauge of how many GW of power are required over how many hours per year to meet demand. Traditional wisdom held that the flatter a load duration curve, the easier it is to satisfy. However, storage and VRE generation challenge this assumption. Nevertheless, very steep and irregular load duration curves continue to signal challenges for electricity supply. Thus, studying load curves, residual load curves and load duration curves of different net zero scenarios under different constellations remains instructive to provide an overview of the structure and challenges for different demand and generation mixes.

One important point arising from this analysis is that in 2050 all scenarios will have very different, much less regular load curves than in traditional electricity systems. This is true for Switzerland in an even more pronounced fashion due to its large amount of hydro pump storage and high degree of interconnection. Figures 4.12a and 4.12b show that even for an LTO scenario in a trade constellation with 100% of current interconnection capacities, the load curves will be quite irregular. The challenge will be even somewhat greater for the same scenario in autarchy (Figures 4.13a and 4.13b).

As already discussed in different contexts, the greatest challenge will be constituted by operating a VRE only scenario under autarchy. The large charging requirements of all available storage and flexibility providers, including hydrogen production, will demand peaks that are almost double those in the two previous scenarios (see Figures 4.14a and 4.14b). This can also be seen in the steep and irregular load duration curve with large excess production indicating the need to curtail VRE generation that can no longer be absorbed through electricity exports.

Figure 4.12. **Load curves and load duration curves for the LTO scenario at 100% of 2022 interconnection capacity (GW)**

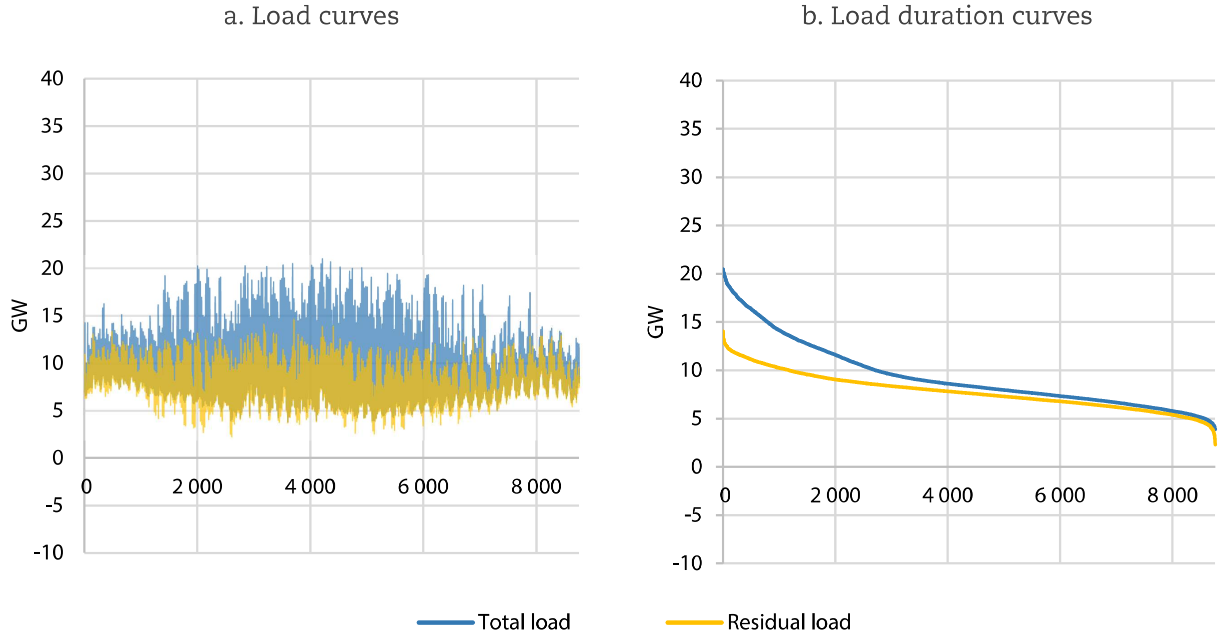


Figure 4.13. **Load curves and load duration curves for the LTO scenario in autarchy (GW)**

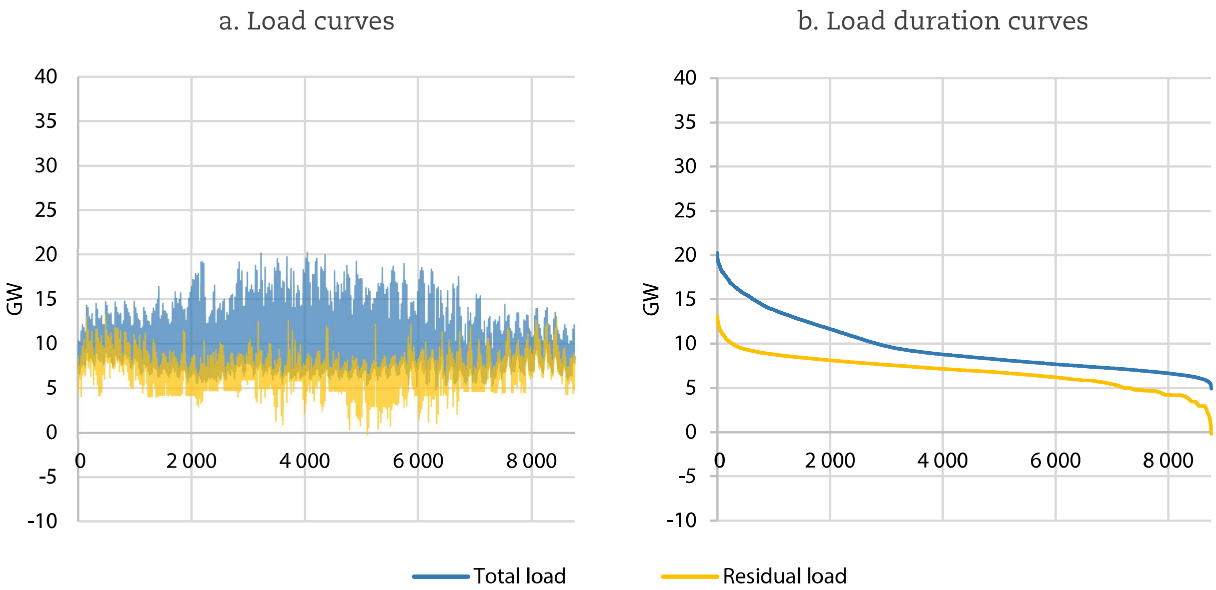
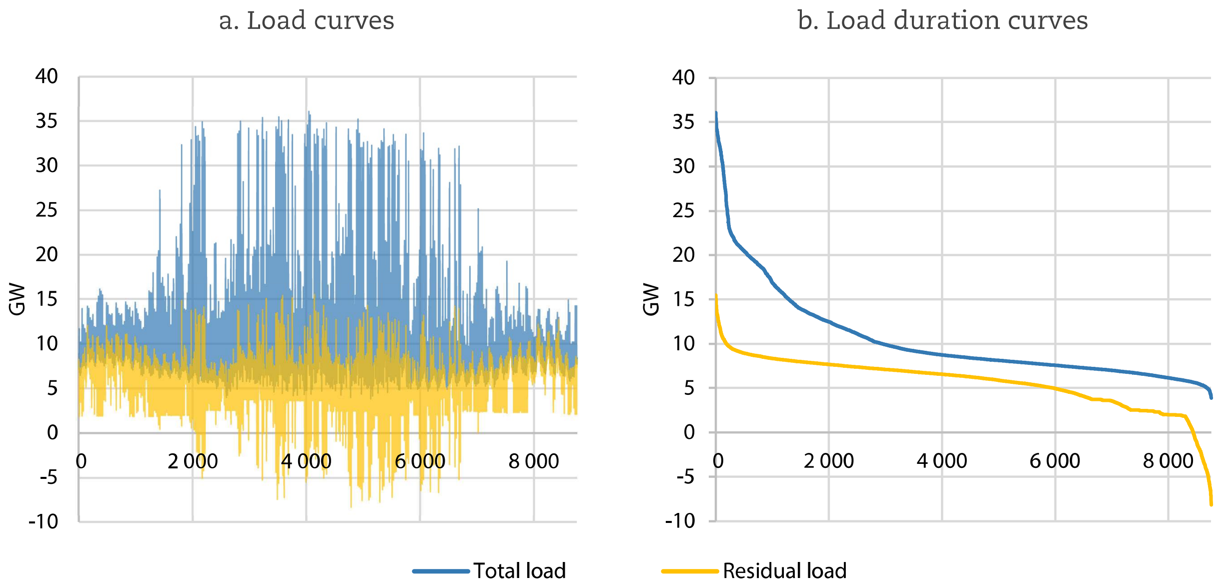
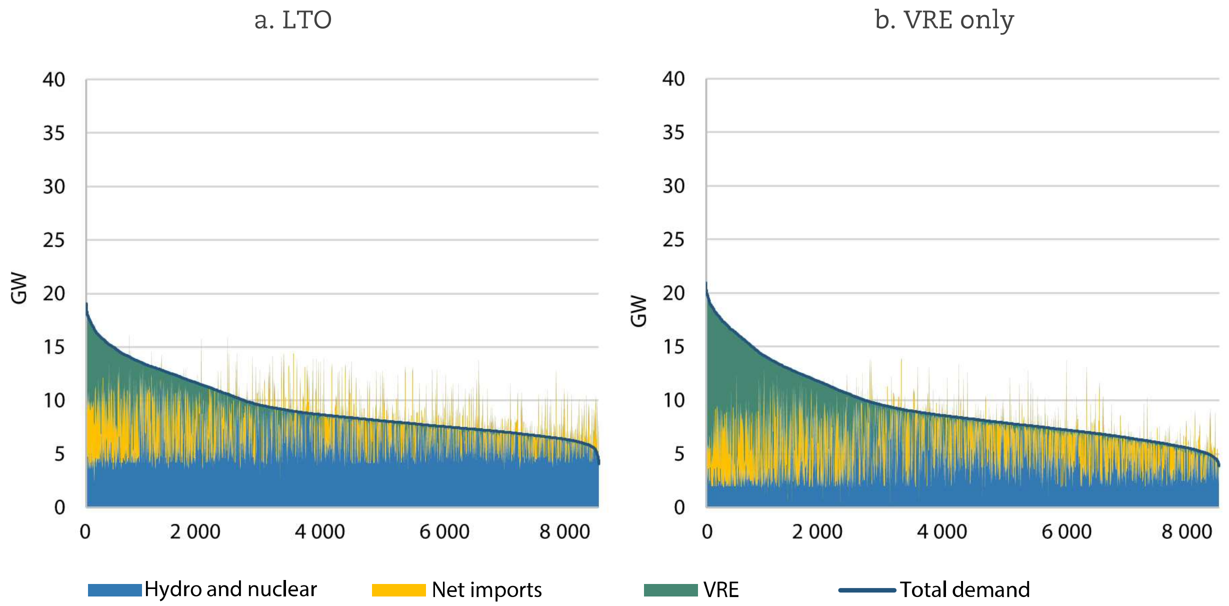


Figure 4.14 **Load curves and load duration curves for the VRE only strategy in autarchy (GW)**



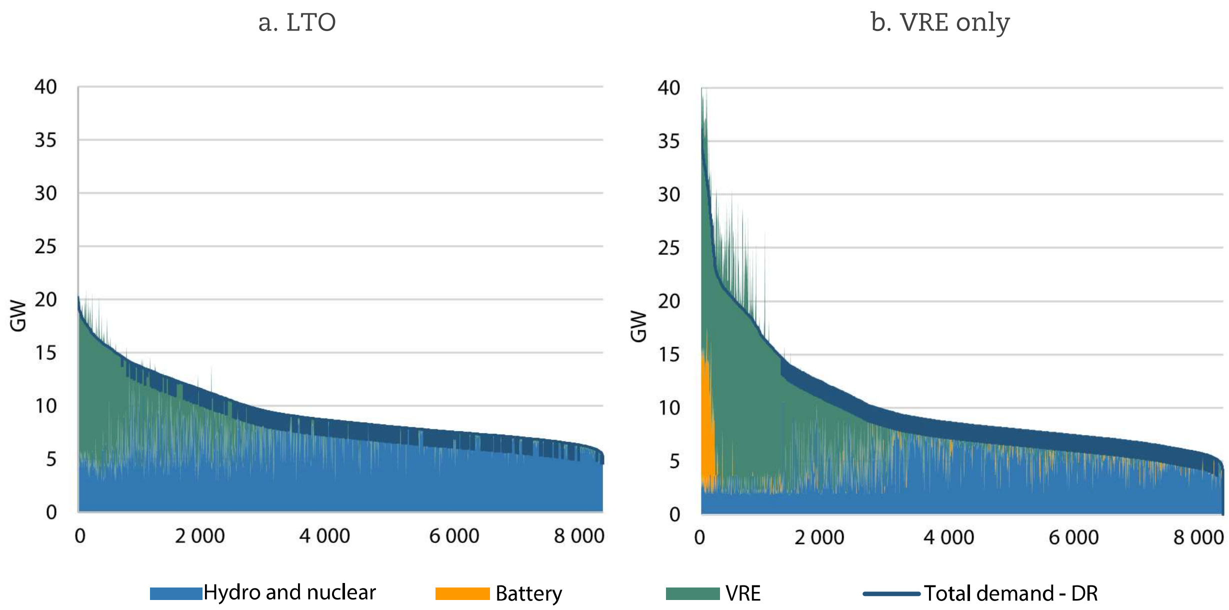
Load duration curves, when augmented with an analysis of hourly supply, can indicate also what happens at the boundaries of the system. This refer to excess production during certain hours, which is either exported or in the case of the autarchy constellation for electricity trade, curtailed. Figures 4.15a and 4.15b thus overlay total net load (total load minus voluntary demand response, whose amounts are minor with open interconnections) and generation in the LTO and VRE only *net zero* scenarios at 100% of Current Interconnection capacity. One can see how VRE generation (green) and electricity imports (orange) are greater in the VRE only scenario, which is compensated by a lower level of dispatchable generation (blue). The latter is composed of hydroelectricity generated by different technologies, nuclear and thermal energy. The most interesting element, however, may well be the excess production during certain hours. This is electricity that will be exported to neighbouring countries. As discussed above, while their physical amount is lower than the imported quantities, their economic value is markedly higher in the LTO scenario and relatively higher in the VRE only scenario.

Figure 4.15. **Load duration curves of the LTO and VRE only scenarios at 100% of 2022 interconnection capacity (GW)**



The same analysis of the LTO and the VRE only scenario under autarchy (see Figures 4.16a and 4.16b) shows, of course, no trade flows, neither for electricity imports, nor for electricity exports. However, it illustrates the increasing importance of voluntary demand response to establish the demand and supply balance during hours of low VRE generation. Demand response means that consumers consume less than they would have and are remunerated for doing so. In a least-cost optimisation model such as POSY, this means that this is the most cost-effective manner of balancing the system. This holds especially in the VRE only scenario as no new dispatchable generation capacity is being built.

Figure 4.16. **Load duration curves of the LTO and VRE only scenarios in autarchy (GW)**



The second observation in the VRE only scenario under autarchy is that during certain hours of strong VRE production, when all storage facilities are exhausted, there is no conceivable way of absorbing the energy that is being produced by the large solar PV and wind capacities. Their surplus energy is thus curtailed, which means that certain VRE generators are disconnected from the grid during such surplus hours.

Focus on prices

POSY is a linear optimisation model that indicates, in function of the exogenously set constraints on certain technologies, the least-cost generation mix. The key input in its algorithm, other than a number of technical constraints, is the set of costs of the different admissible technologies. The indispensable pivot in this exercise is the price mechanism. This also ensures that the least-cost scenarios generated by POSY could result equally from the centralised decisions of an optimising planner or from the results obtained based on decentralised profit maximisation in a perfectly competitive electricity market. The price in a competitive electricity market is equal to the variable costs of the marginal technology, i.e. the technology with the highest variable costs that is still dispatched during a given hour.

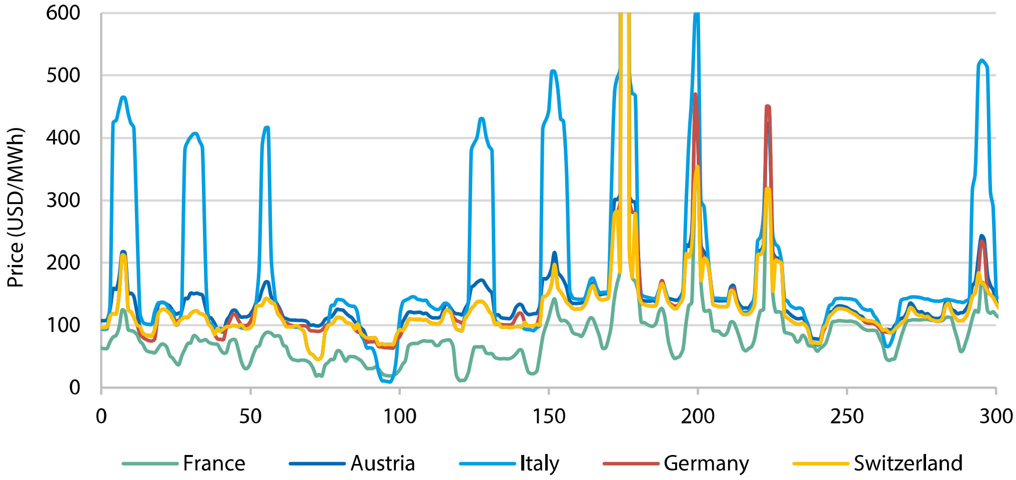
The challenge in the Swiss energy system is that there are essentially no domestic variable costs, or if they exist, they are hard to identify. Solar PV, wind, hydro run-of-the-river, nuclear and thermal are dispatched in Switzerland without reference to market prices. Hydro reservoir and pump storage are dispatched according to complex algorithms of inter-temporal opportunity cost optimisation. And yet, Switzerland has a competitive spot electricity market with hourly prices as do countries where load-following nuclear energy, coal or gas set prices. Swiss prices are well comparable to those in other European countries. So how are prices set in the Swiss market?

Swiss domestic prices are set by the prices that prevail in the countries with which it trades electricity. Prices in France, Germany and Italy thus determine Swiss prices at its borders (Austrian prices are closely correlated with German prices). More specifically, the highest price among the prices prevailing at the unsaturated interconnections (once interconnections are saturated prices diverge) will set the Swiss domestic prices. One must think as the price of a MWh imported from France or Germany or of a MWh exported to Italy as the marginal costs that determine the price in Switzerland. As Swiss total electricity consumption is small compared to these three countries, one can assume that Swiss low variable costs production in return has little or no impact on the prices in its neighbouring countries.

This gives the electricity prices prevailing in its European neighbours a great influence on price formation in the Swiss market. This is a straightforward reality in 2022. However, what about 2050? What will be the prices in France, Italy and Germany then? Switzerland can, of course, choose its domestic generation mix. However, the economic costs and benefits of the different options will depend on the interaction with the structure of prices determined at its borders. The exception is, of course, constituted by the scenarios in autarchy, which has the inconvenience of being the most expensive solution.

As set out in Chapter 3, determining the right 2050 prices in the four EU countries is an important exercise that needs to be approached with care. The price simulations from the University of Basel that were also employed in the JASM modelling effort (Panos et al., 2021), were thoroughly analysed and considered a convincing option for modelling European electricity prices. In complement to the general discussion in Chapter 3, Figure 4.17 provides here a particularly evocative snapshot of the interaction of Swiss electricity prices (red) with those of its European neighbours for two weeks during the months of February with a high price peak. As long as the large interconnection with high-price Italy remains open, Swiss prices will follow Italian prices (green). If it is saturated, they will follow Germany prices (yellow). France with its comparatively low prices rarely sets prices in Switzerland but benefits, of course, from exporting its low-cost electricity into the Swiss market.

Figure 4.17. **Electricity prices in Switzerland and its four neighbouring countries (USD per MWh)**

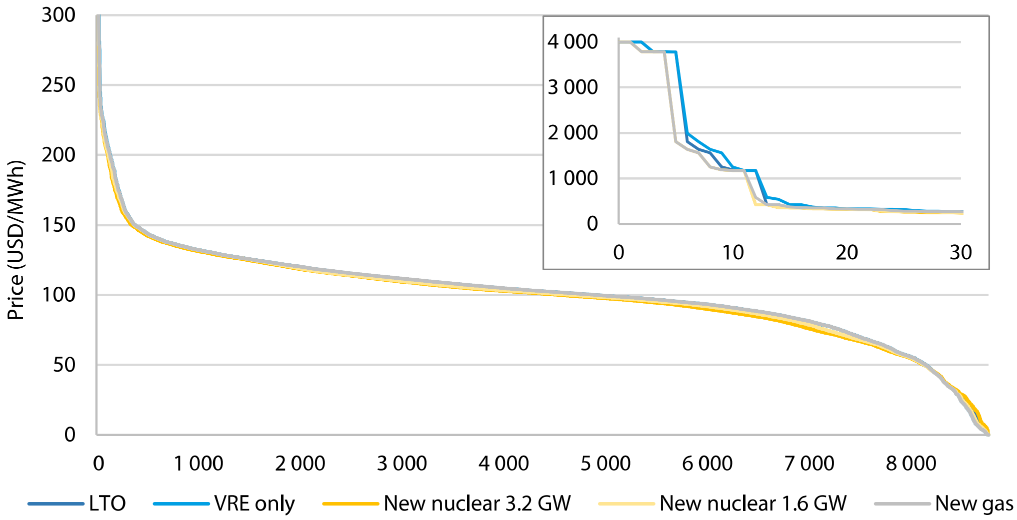


Note: Two weeks in February

Source: SCCER (2022) data platform of the JASM study (Panos et al., 2021)

Letting prices at the Swiss border determine domestic prices is not only an elegant and efficient modelling procedure, it also corresponds to reality[2]. However, it also has an inconvenience: taking one set of European electricity prices in 2050 as the basis for Swiss prices does not allow the differentiation of the price dynamics in the five net zero scenarios. Figure 4.18 shows the five almost identical price duration curves for Swiss domestic prices in the different scenarios in the trade constellation with 100% of current interconnection capacity. The 50% case looks also very similar. The small inset shows the prices for the highest 30 hours. It can be seen that during 12 hours per year scarcity situations make for very high prices indeed, which again is something that is regularly observed in the European EPEX Spot market in which Switzerland participates. Small differences are due to moments during which certain interconnections are saturated in some scenarios but not in others.

Figure 4.18. **Annual price duration curves in the five net zero scenarios at 100% of current interconnection capacity (USD per MWh)**



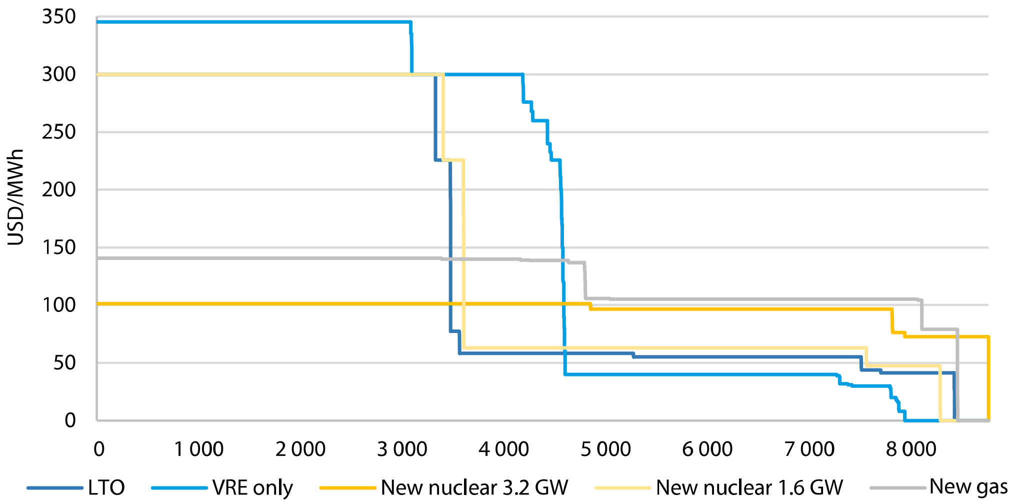
2. In the autarchy scenarios this is, of course, not possible. Prices were thus modelled as the dual of the supply constraint, i.e. the marginal cost of capacity expansion at every given hour.

The fact that domestic prices are almost identical in the five net zero scenarios is readily explained if one believes that European electricity prices and Swiss decisions about a future net zero generation mix are uncorrelated. If that is true, and the price series of the University of Basel's *decarb* scenario (Panos et al., 2021) constitute reasonable estimates, then all is well. Things become more complicated if specific net zero generation scenarios and EU prices (which in return result from European policy decisions) were linked in different manners. Would an LTO scenario become more or less likely if Switzerland's neighbours themselves continued to invest in nuclear energy and thus electricity prices at Swiss borders were lower? Vice versa, should a more volatile EU pricing regime be tested for the VRE only scenario? If the New gas scenario assumes a carbon price of USD 100 per tCO_2, does this not mean that Europe probably acted similarly, assuming European prices should be higher? These are the sort of questions that could be asked in front of the, again, otherwise logical hypothesis that Swiss electricity prices are set by the prices of its trading partners at its borders.

The electricity trade constellation of assuming a closed Swiss electricity system in autarchy, by definition, avoids such issues. In this case, Switzerland determines, so to say, its own prices. However, the issue that very little dispatch in Switzerland is operated in function of explicit and transparent costs has not disappeared. At the level of modelling, solutions exist: the POSY model in this case calculated the dual (the implicit cost) of the supply constraint at each hour. It thus provides an only partially satisfying answer to the question, what would be the cost of expanding the system in a least-cost manner so that it produced one additional MWh, including in the calculus the fixed and variable costs of all available technologies. As an intellectual exercise, this is a satisfying procedure and produces well differentiated price duration curves for the five scenarios that correspond to intuition. Producing an additional MWh in a VRE only system is sometimes very expensive and sometimes not expensive at all, for instance, during periods of curtailment. The more baseload power production is available around the clock, the more stable are the costs of an additional MWh (see Figure 4.19).

However, a competitive least-cost dispatch can only be organised based on explicit short-run marginal, i.e. variable costs. Assuming a Swiss electricity system in which decisions are made instead based on the dual of the supply constraint, would in essence assume to substitute market dispatch with the centralised dispatch of an independent system operator. This is not an unconceivable vision of the future given the very real organisational challenges faced by low-carbon systems which inevitably are low marginal cost systems. These are, of course, issues that this report can only touch on in passing. In conclusion, however, one can state that assumptions concerning the modelling of price formation in 2050 pose several intricate questions concerning the degree of Swiss policy co-ordination with its neighbours, the openness of its interconnections, and the market design of its electricity system.

Figure 4.19. **Annual price duration curves in the five net zero scenarios under autarchy (USD per MWh)**



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Chapter 5: Conclusions

Given a low-carbon electricity system defined by high shares of hydropower and nuclear power, and with among the lowest carbon intensity in the world, Switzerland is well positioned to attain its declared objective of net zero carbon emissions by 2050. However, while agreement on the need to achieve net zero exists in Switzerland, the pathway to net zero remains open. While Switzerland voted to no longer allow construction of new nuclear power plants, it also voted not to limit the operating period of the existing nuclear power plants – inherently preserving the option of extended operations of nuclear power plants. Despite uncertainties regarding the integration of its electricity market with Europe, Switzerland also plays, and will continue to play, a significant role in European electricity markets due to its reliable baseload generation and its flexible hydropower reserves. The complementarity of Switzerland's electricity system with those of its neighbours facilitates the realisation of mutual benefits in two dimensions: first, the security of electricity supply, and second, the commercial gains from electricity trading. The 2050 net zero scenarios reveal that both aspects will require increasing vigilance, partly due to the variability of renewable energies such as solar PV and wind that are bound to play an increasing role in the future Swiss electricity generation mix. In this context, the question of extending the operational lives of Swiss nuclear power plants, particularly the two youngest (Gösgen and Leibstadt), can be raised. As the Swiss public and federal government have not supported legally determined limits on the duration of the operation of nuclear power plants, their operation beyond 60 years can offer a potential cost-effective contribution for Switzerland to achieve its net zero emission objectives in 2050.

Electricity system cost analysis offers an appropriate methodology to assess distinct net zero carbon scenarios with different shares of variable renewable energies (VRE) and nuclear energy. Increasing VRE penetration in energy systems has questioned the usefulness of the levelised costs of generating electricity (LCOE) methodology as the sole measure of cost for comparing different electricity systems. System costs analysis pioneered by the Nuclear Energy Agency (NEA) covering profile, balancing, grid, and connection costs provides a fuller picture of true costs, especially for low-carbon electricity systems. Thanks to methodological advances and progress in modelling software, mixed-integer linear programming (MILP) models that are capable of combining a number of technical constraints with an economic least-cost optimisation emerge as the most appropriate instrument for this task. In partnership with industry stakeholders and academic experts, the NEA POSY model for analysing integrated low-carbon electricity systems has been developed as an effective tool for exploring the system costs of different energy policy choices, all adhering to the same carbon constraint of net zero emissions. The results of the present study constitute a contribution to a broader discussion on the cost and performance of electricity systems in the scientific literature. Existing literature on the Swiss context supports the low-cost nature of extensions to nuclear power operation, and also makes evident the need for models including nuclear power plant operation beyond 60 years in the Swiss electricity generation mix. By deepening the study around this unexplored aspect, the present report aligns with the literature and contributes to it.

In comparison, the scenarios in the present report are somewhat more cautious with respect to the development of variable renewable energy capacity in a context of attaining net zero emissions in 2050 in a cost minimising manner, as long as international electricity trade continues at current levels. This even holds for the scenarios without nuclear energy. As long as interconnection capacity remains at present levels, total capacity of VRE is estimated to be 19% of total generation capacity in the scenario with long-term operation (LTO) of existing nuclear power plants, and 28% in the scenario without LTO where capacity expansion is based exclusively on VRE.

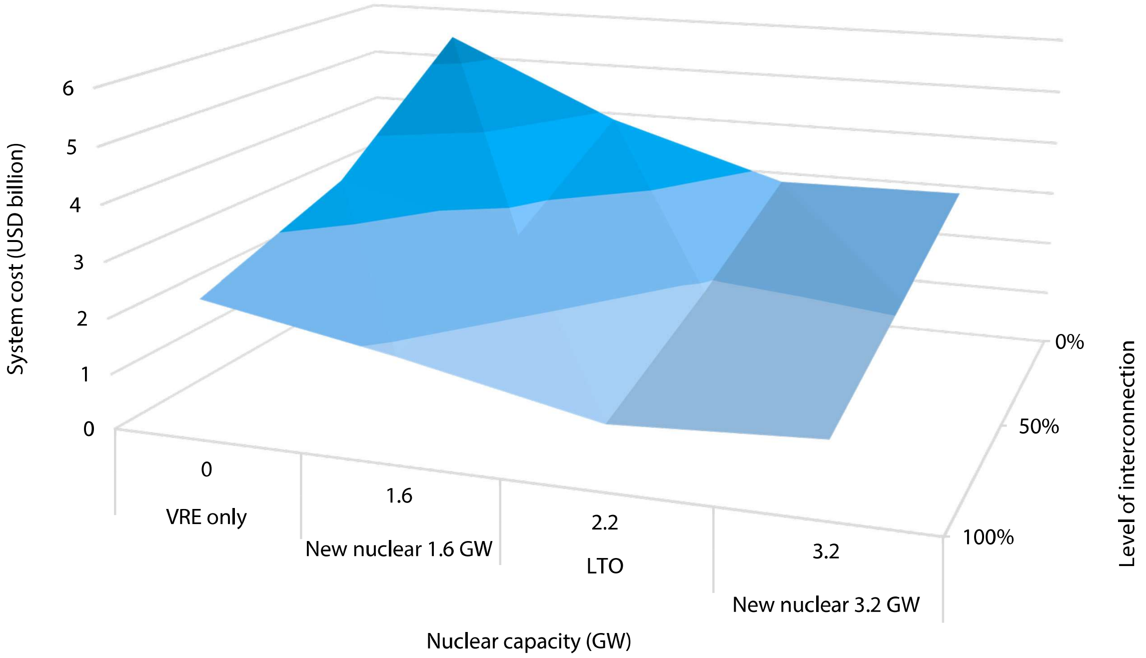
Only in autarchy control scenarios, where no electricity trade is allowed, the present report also arrives at a share of 52% of total generation capacity for solar PV and wind capacity in the presence of nuclear LTO, and at 65% of VRE capacity in the absence of nuclear LTO (see Chapter 4 for more details). These results confirm the importance of adopting realistic assumptions about the evolution of Switzerland's electricity trade with its neighbouring countries and correctly modelling their implications. It is hard to overstate the impact that electricity trading has on the relative costs of a VRE only strategy. On the one hand, electricity trading reduces the costs of all scenarios in the Swiss context, including those with a VRE only strategy. However, electricity trading will also benefit scenarios with extended nuclear LTO relatively more than those with VRE only strategies.

The results of the cost-optimisation studies are established over 8 760 hours per year by the POSY MILP model. A thorough validation exercise performed on the basis of detailed 2019 time series data provides confidence in modelling results capturing the essential functional aspects of the Swiss electricity system. Switzerland's electricity system poses unique modelling challenges due to the fact that most of its generation technologies have very low or zero short-run marginal costs and that its interconnection capacity is at the level of its peak capacity. Electricity prices in neighbouring countries and at interconnection points are thus particularly closely aligned with Swiss domestic prices. Electricity trading also assumes great importance in the 2050 net zero scenarios. In particular, baseload nuclear power not only allows a reduction in domestic generation costs, but also allows Switzerland's flexible hydro resources to concentrate on maximising profits from electricity trading, which may be difficult to maintain with higher VRE penetration. Dispatchable capacity such as nuclear energy consistently improves net trade revenues. Adding variable capacity such as wind and solar PV, whose production is determined by the weather rather than by prices, instead decreases net trade revenues and thus increases economic system costs. Using Switzerland's high level of domestic flexibility resources to compensate for VRE variability would thus add to the overall costs of satisfying domestic demand. However, if Switzerland would decide to bear these added costs these resources could ensure the technical viability of a VRE only strategy under the condition that the profile of electricity demand remains comparable to that at the time of writing and interconnections with neighbouring countries remain open.

Modelling results from this study indeed show that maintaining interconnection capacity at current levels increases gains from electricity trading and reduces costs in all five net zero scenarios. Sufficient interconnection capacity is also critical for the security of electricity supply. Without interconnections and the ability to import or export electricity, a VRE only scenario would not only be expensive but would also limit the Swiss electricity system's resilience of supply. Together, the absence of electricity trade as a source of flexibility and the presence of a very important level of VRE capacity requiring high levels of flexibility, imply that all domestic flexibility resources would need to be mobilised to their maximum level with little residual capacity to absorb unforeseen shocks. While all five scenarios have the same security of supply constraint, satisfying hour by hour a demand profile derived from the well-regarded JASM study (Panos et al., 2021), their costs differ greatly, more than doubling in certain cases. The analysis shows that the most cost-effective pathway to reach Switzerland's net zero objective in 2050 is to continue operating the country's two youngest nuclear power plants, while maintaining current capacities of interconnections for electricity trading with its neighbours. A purely theoretical comparison in the Swiss case shows that building new nuclear power plants arises as the alternative scenario with the lowest economic system costs.

Figure 5.1 briefly summarises the total system costs of different scenarios grouped along two axis, the amount of nuclear generation capacity and the degree of interconnection between Switzerland and its neighbours. It shows that higher degree of interconnection always reduces system costs. It also shows that LTO of Switzerland's two newest nuclear power plants is the most cost-effective solution in terms of the contribution of nuclear power to achieving net zero. However, even incurring the fixed cost for new nuclear capacity would be more cost-effective than a VRE only strategy.

Figure 5.1. **Total system costs as a function of nuclear capacity and interconnection levels**



Note: For expositional purposes, Figure 5.1 does not include the New gas scenario.

As stakeholders in the lively Swiss energy debate assess current and future pathways to net zero, the present study could provide a timely contribution with three highly robust conclusions based on sound methodology. First, scenarios built on a generation mix of renewables *and* nuclear baseload have consistently lower system costs than scenarios based exclusively on renewables such solar PV and wind. Second, while more expensive, Switzerland's high level of domestic flexibility resources renders a VRE only strategy technically feasible as long as the profile of electricity demand, as well as the interconnection capacity allowing for electricity trade with neighbouring countries, remain at current levels. The ability to trade internationally remains an important additional flexibility resource for the Swiss electricity system.

All five scenarios, whether built around the long-term operation of existing nuclear power, the exclusive reliance on solar PV and wind, the hypothetical construction of new nuclear power plants, or the installation of new gas capacity, have lower costs with open interconnections for electricity trading than in autarchy. Third, a VRE only strategy to reach net zero in 2050 without interconnections in autarchy would not only be very expensive but would also move the Swiss system further away from security of supply resilience despite the high level of Swiss domestic flexibility resources. The feasibility of such a scenario relies on the constant availability of all flexibility resources, including a substantial level of flexible hydrogen production, with little room for error. Furthermore, in such a scenario, the amplitude and frequency of ramps would be considerable and pose questions for technical feasibility.

It is hoped that the current study, prepared on the basis of detailed data, extensive consultation with stakeholders, and a state-of-the-art modelling methodology can make a useful contribution to both modelling efforts as well as current and future Swiss energy policy discussions.

Annex A. Focus on the production profile of flexible sources

In this report, flexibility of a production source refers to the ability to provide electricity at short notice, but not necessarily for extended periods, in order to compensate for the temporary shortfall of other generating sources. Typically, flexibility is prized to complement the variability of solar PV and wind. Moreover, outages due to technical problems or sudden demand bursts may also require activation of flexibility resources in order to maintain the balance of electricity demand and supply at all times. This is crucial, as the stability of the grid and hence continuous supply depend on this balance. Indeed, any disturbance, in the absence of sufficient flexibility resources, would lead to outages with long delays for restarting operations.

Switzerland has an unusually large set of low-carbon flexibility providers at its disposal. First and foremost, 3.58 GW of **hydro pump storage** facilities form the bedrock of its domestic flexibility provision. This amount of storage is considered to be available in all scenarios of this study. It is complemented by 1.4 GW of voluntary demand response, i.e. electricity customers willing and capable of reducing or shifting their consumption, against remuneration, during times of need. Added to these two options common to all scenarios, further flexibility sources can be called upon if the situation requires and prices are sufficiently high and are optimised by the POSY model. These added flexibility sources include **hydro reservoirs**, **batteries, VRE curtailment**, the flexible production of hydrogen and the use of **interconnections**.

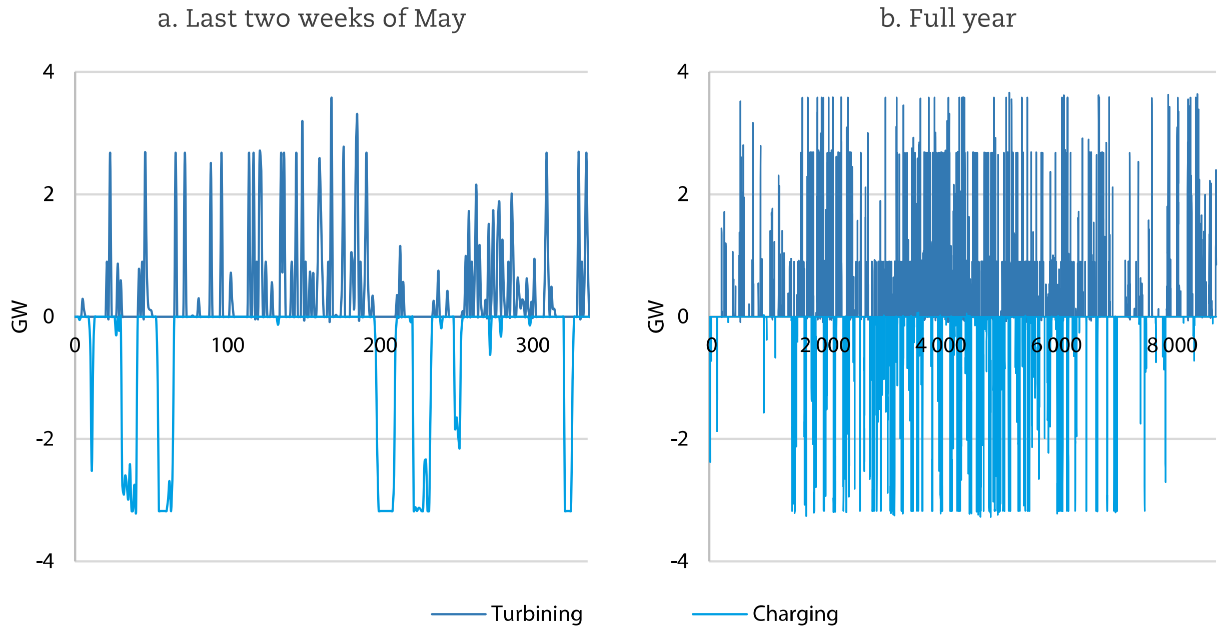
The objective of this annex is to show the contribution of each flexibility source available in the Swiss electricity system as a function of time (except for voluntary demand response which can be considered as a reduction of demand at any given moment). Indeed, each flexibility lever does not have the same structural characteristics nor the same constraints. Firstly, some flexibility sources may operate directly on demand, such as hydrogen production; secondly, other sources have an influence on generation (e.g. reservoir of hydroelectricity, VRE curtailment); and thirdly, flexibility providers may play a dual role in establishing the supply and demand balance such as pump hydro resources, batteries or imports and exports. In the following analysis, the different production and/or consumption profiles over time will be presented as graphs. For comparison purposes, the production and consumption profiles are presented in absolute and complemented by a table with key structural parameters.

Flexibility provision of hydro sources

Hydroelectric reservoirs and pump storage units are important providers of flexibility in any electricity system. Although both technologies create electricity by having water pass through a turbine, converting kinetic energy into electric energy, they each have distinct economic characteristics and functions within the electricity system. Hydroelectric reservoirs are lakes created by dams that are replenished by natural resources, such as water inflows from rivers, glaciers or rain. Operators can choose the timing of when to release water and electricity, usually when the latter is at its most expensive, but cannot choose when to replenish the reservoirs. On the other hand, pump storage units, as the name implies, combine a water turbine with a water pump. In this case, operators will choose not only the timing of when to release the stored water but also when to pump it. Logically, their economic model is built on the spread between high-price hours and low-price hours.

Three observations can be made from the annual and bi-weekly production profiles of pump hydro presented in Figures A1 and A2 for the two extreme cases LTO with 100% interconnection and VRE in autarchy. Note that the blue curve shows the positive contribution, which is the production of hydro in turbining mode, while the red curve shows the pumping part and is negative. The average is shown in dotted line. First of all, regardless of whether it is in turbining or pumping mode, the pump hydro is much more heavily solicited in the autarchy with VRE only scenario, both in terms of frequency and level of use. Thanks to the overview of the annual production (see Figures A1b and A2b), the seasonal nature of the charging can be clearly observed, with an increased recourse in the summer period when the domestic demand is lower.

Figure A1. **Pump hydro production profile in the case of a 100% LTO interconnection for the last two weeks of May and the full year**

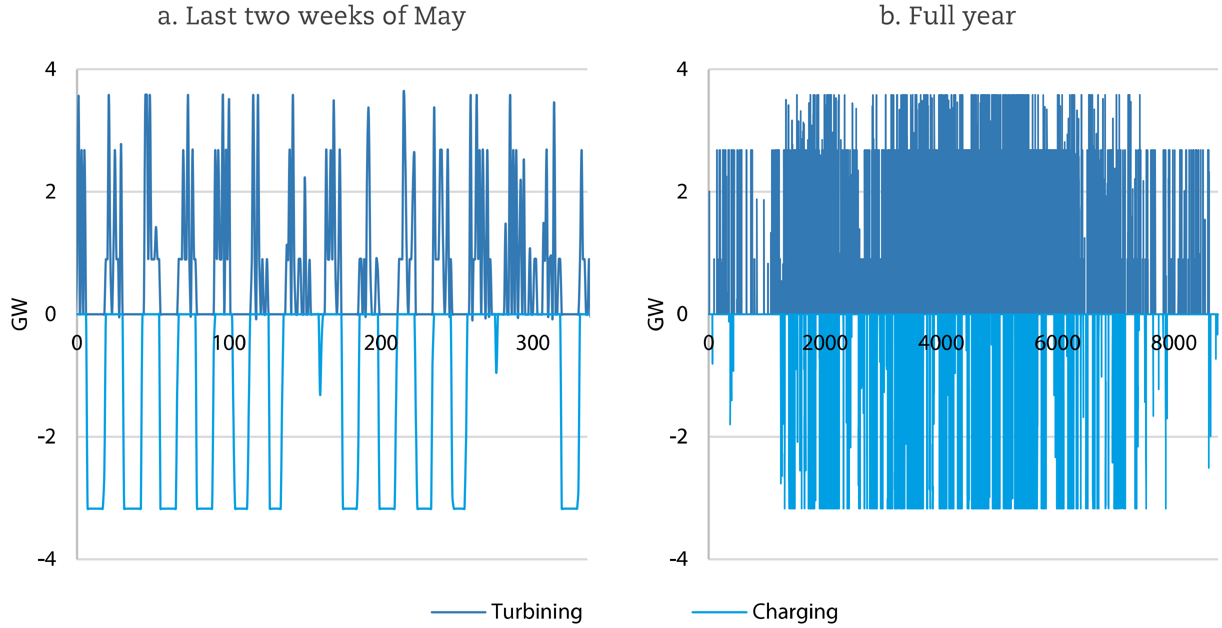


Capacity	**GW**	3.58
Annual production	**TWh**	1.55
Load factor		5.0%
Turbining peak	**GW**	3.58
Charging peak	**GW**	-3.17
Average	**GW**	-0.04
Turbining standard deviation	**GW**	0.56
Charging standard deviation	**GW**	0.72

Secondly, it is interesting to note that the daily production of hydro pump is less regular or even random in the case of 100% interconnection with a mix between nuclear LTO and VRE. This seems to reflect the fact that this technology can be used to manage random imbalances between production and consumption. In contrast, in VRE Autarchy, production follows a more regular pattern with loading at night and production during the day. In this case, pump hydro is primarily used for load-following and only secondarily used to manage unforeseen events. The flexible nature of hydro is then extremely relevant but its type of use depends on the availability of other flexibility levers.

Thirdly, once production reaches 100% of maximum capacity, reloading the following night appears to be immediate; this can be seen in Figure A2a. In addition, pumping is carried out according to the needs of the network and to meet the demand.

Figure A2. **Pump hydro production profile in the case of VRE Autarchy for the last two weeks of May and the full year**

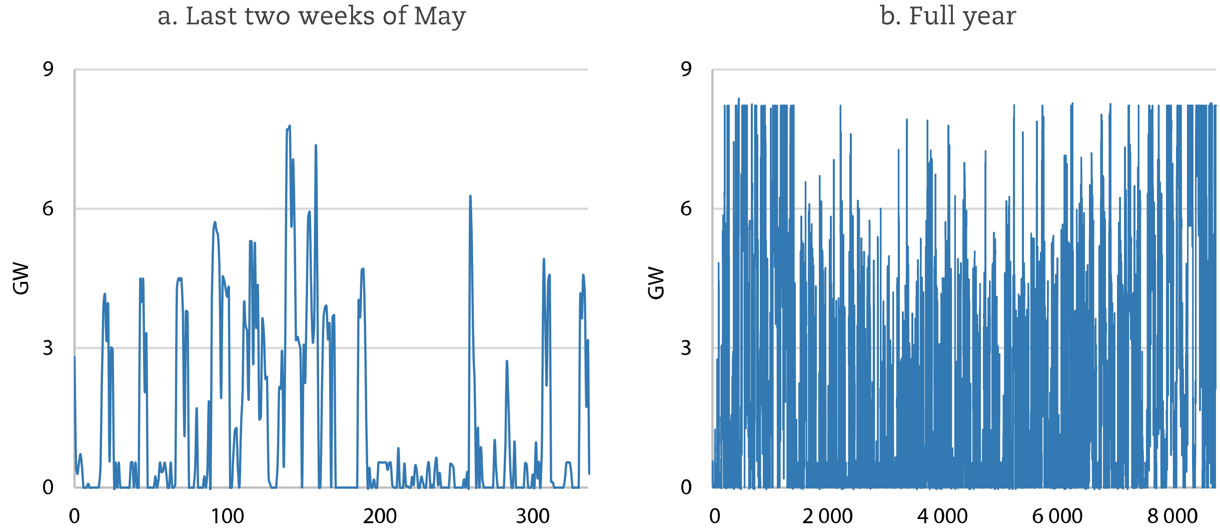


Capacity	**GW**	3.58
Annual production	**TWh**	3.63
Load factor		11.6%
Turbining peak	**GW**	3.58
Charging peak	**GW**	-3.17
Average	**GW**	-0.10
Turbining standard deviation	**GW**	0.90
Charging standard deviation	**GW**	1.13

Concerning the second type of hydropower source from reservoirs, Figures A3 and A4 show the bi-weekly production profiles for May and the overall annual production. As the operation of the hydro reservoirs is not reversible, the contribution of hydro reservoir is only positive. The same phenomenon of a more chaotic production for the LTO scenario with full interconnection capacity than for the VRE only strategy in autarchy is observed in Figures A3a and A3b. Indeed, no clear and regular pattern on the production profile emerges, in contrast to the autarchy scenario (see Figure A4a), which shows a plateau and then a peak in the hydro production per day.

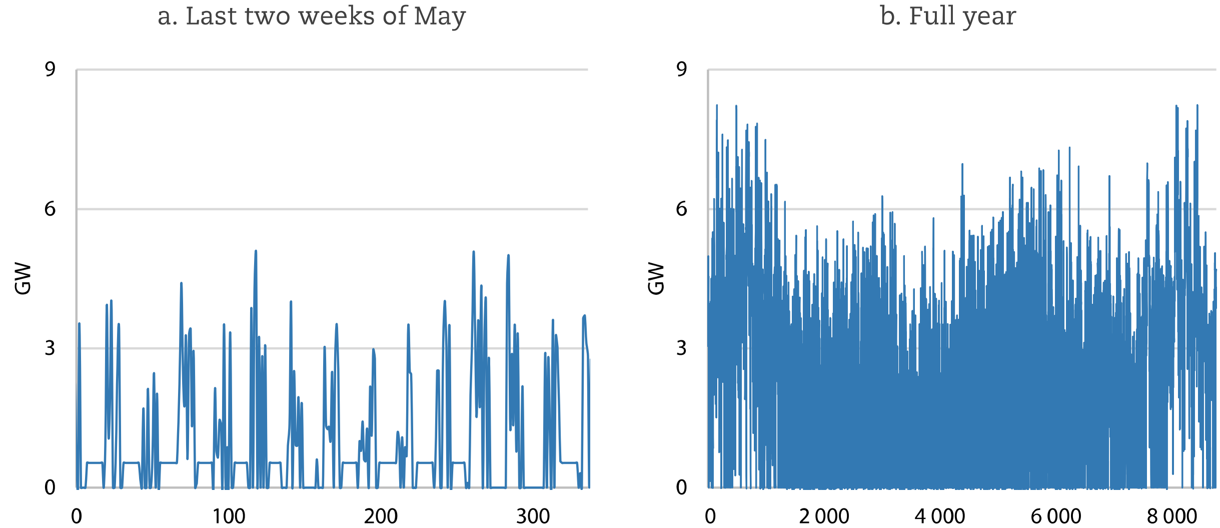
Moreover, the maximum of installed capacity is frequently reached, especially during the winter months in the case of LTO 100% interconnection. This observation completes the argument on the use of hydraulic technology in the case of the LTO 100% interconnection scenario, which is preferred for its flexible and dispatchable characteristic to take advantage of opportunities to trade with neighbouring countries and benefit from attractive prices, instead of supporting the domestic and charging demand only. In other words, the chaotic behaviour of both pump hydro and reservoir for cases with interconnection could indeed be interdependent. On the contrary, in autarchy, the hydro reservoir seems rather necessary for load-following operation, as the profile is more regular and the annual production average is higher (2.25 TWh of averaged production in autarchy with VRE only against 2.14 TWh in LTO 100% Interconnection). This is due to the fact that the system is looking for stable and controllable solutions such as nuclear or imports, which it no longer has, with the exception of the hydroelectric reservoir which is becoming its major resilient energy source for ensuring security of supply.

Figure A3. **Hydro reservoir production profile in the case of LTO interconnection 100% for the last two weeks of May and the full year**



Capacity	**GW**	8.8
Annual production	**TWh**	18.77
Load factor		26.1%
Production peak	**GW**	8.8
Average production	**GW**	2.14
Turbining standard deviation	**GW**	2.55

Figure A4. **Hydro reservoir production profile in the case of VRE only in Autarchy for the last two weeks of May and the full year**

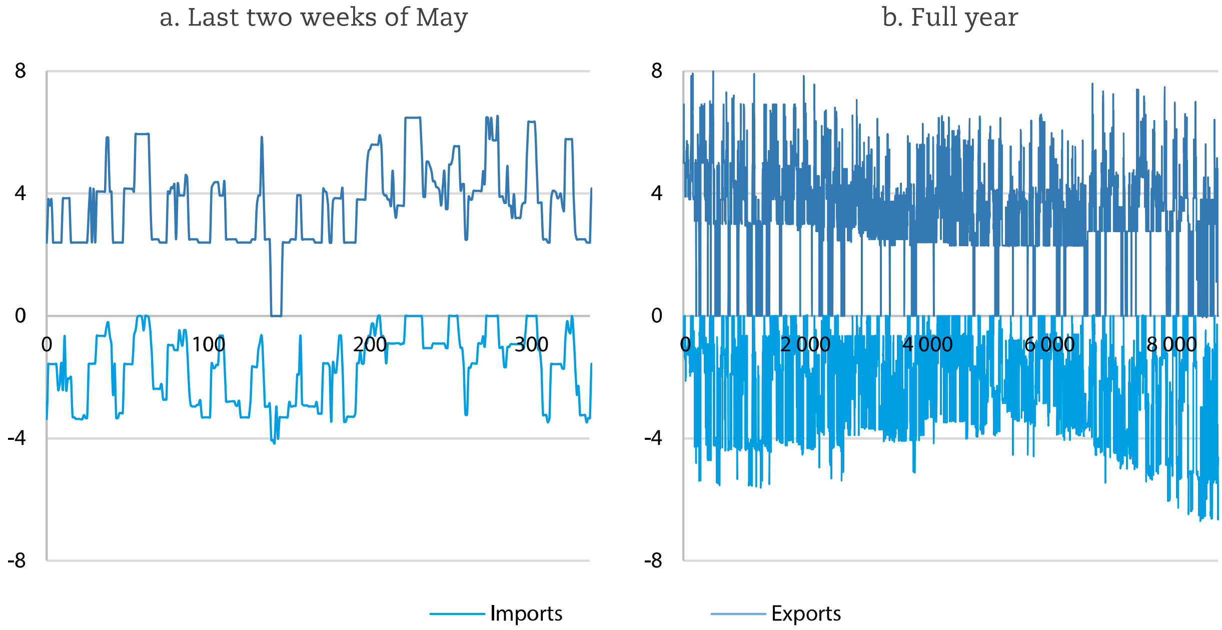


Capacity	**GW**	8.8
Annual production	**TWh**	19.68
Load factor		27.3%
Production peak	**GW**	8.8
Average production	**GW**	2.25
Turbining standard deviation	**GW**	1.93

Role of interconnection in terms of flexibility

The approximately 10 GW of interconnection are an extremely important source of flexibility, that combined together with hydroelectric resources allows for system constellations that could not be realised in countries with less abundant flexibility resources. Such abundant flexibility resources facilitate, in principle, the integration of large amounts of variable renewables (VRE) such as solar PV and wind. Results of the 100% interconnection constellation are shown in the figures A5 and A6. Note that for the negative part of the curves, the more negative is the red curve, the more Switzerland exports part of its production to its neighbouring countries. A first observation is that Switzerland exports and imports at the same time, which illustrates the fact that Switzerland trades with its neighbours and makes its trade more profitable

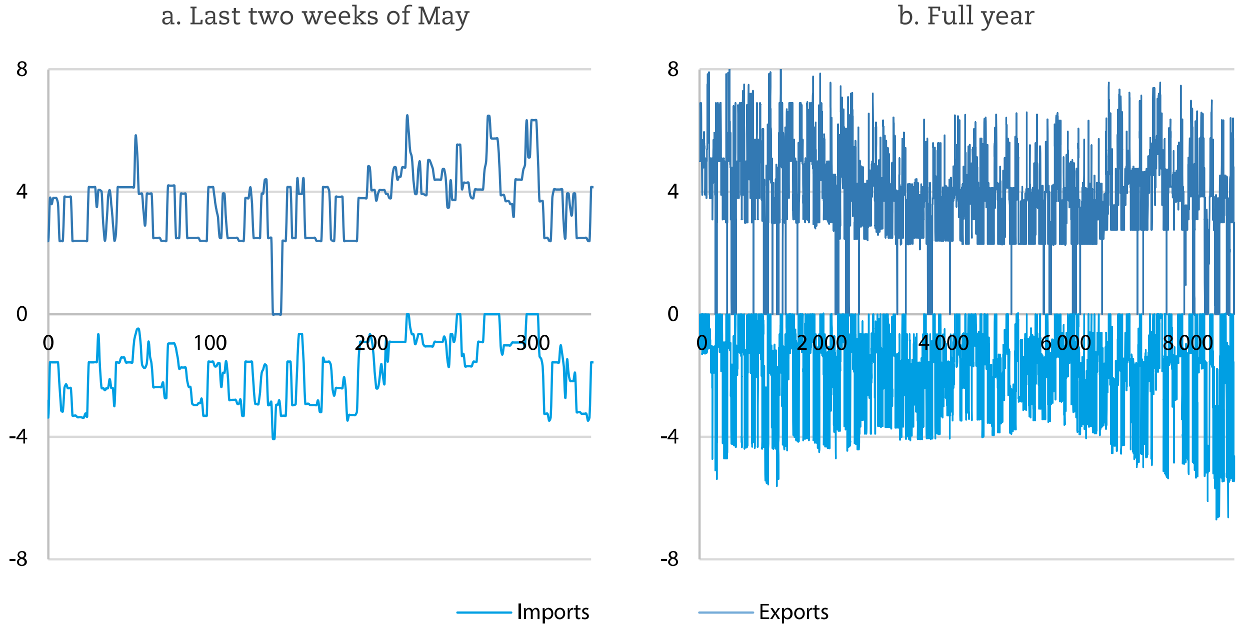
Figure A5. **Physical flows of imports and exports profile in the case of LTO 100% interconnection for the last two weeks of May and the full year**



		Imports	Exports
Capacity	**GW**	8.9	11.3
Annual flow	**TWh**	30.34	21.10
Net imports	**TWh**	9.23	
Peak	**GW**	8.11	6.70
Average	**GW**	3.46	2.41
Standard deviation	**GW**	1.49	1.56

In a second reading, the average of imports is higher while exports are lower in the case of a 100% renewable strategy (VRE only), which again shows that interconnections are an essential lever in the flexibility arsenal of the Swiss electricity system in case there is no dispatchable source other than hydropower.

Figure A6. **Physical flows of imports and exports profile in the case of VRE only with 100% interconnection for the last two weeks of May and the full year**



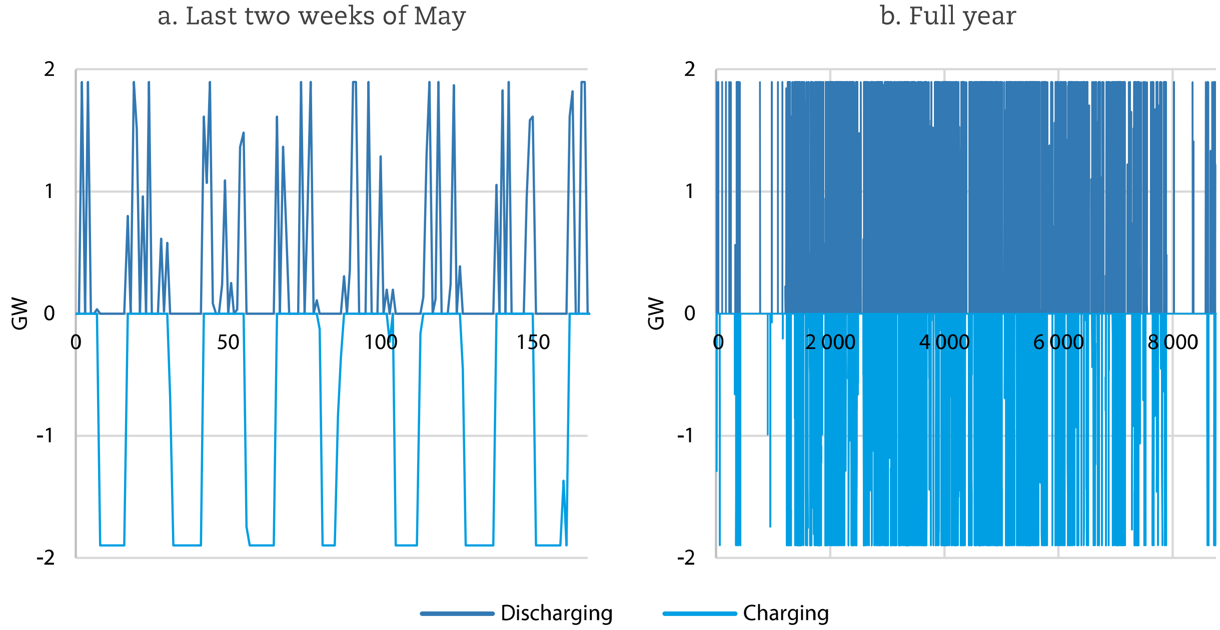
		Imports	Exports
Capacity	GW	8.9	11.3
Annual flow	TWh	34.53	16.92
Net imports	TWh	17.62	
Peak	GW	8.11	6.70
Average	GW	3.94	1.93
Standard deviation	GW	1.36	1.44

Additionally, at first reading, the import and export profiles of Switzerland in regards to its neighbouring countries, in particular the annual profile in Figures A5b and A6b, do not depend on the considered scenario, i.e. on the share of variable renewables in the grid. Indeed, the profiles are similar in both scenarios with long-term operation of nuclear or with a VRE only strategy.

Use of batteries on a large scale

The batteries work on the same principle as pump hydro with a charging/discharging mechanism depending on market conditions and demand. It should be noted that this battery charging/discharging option is relatively expensive and is therefore exclusively used in the VRE only scenario in autarchy.

Figure A7. **Battery profile in the case of a VRE only in Autarchy for the second week of May and the full year**



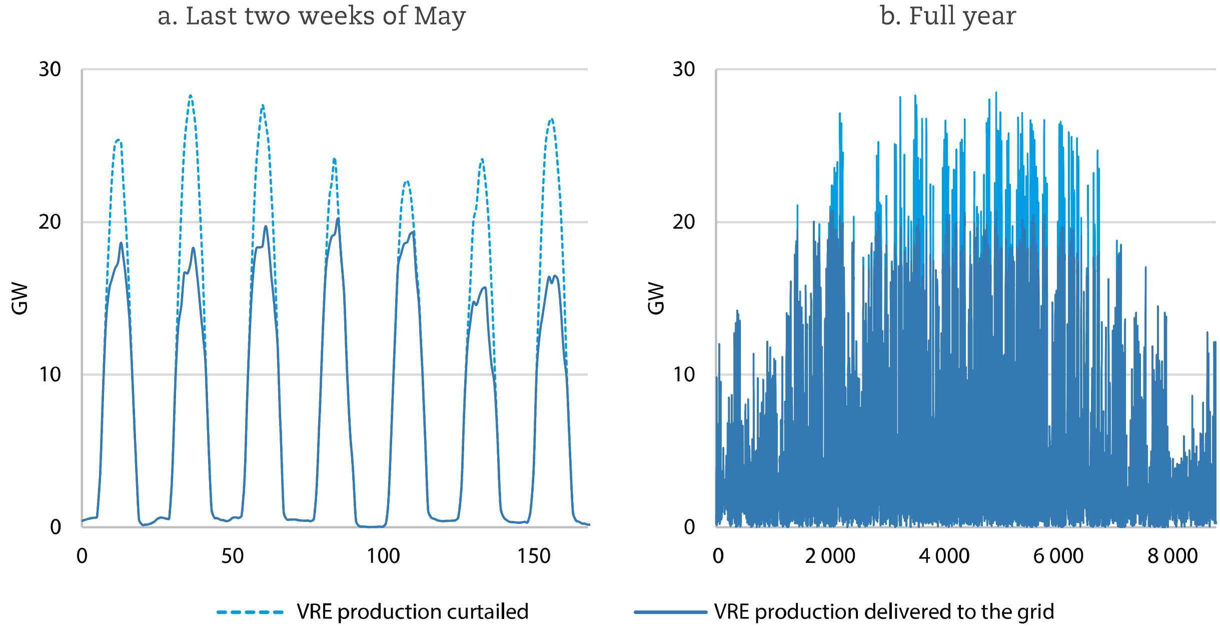
		Discharging	Charging
Capacity	**GW**	1.9	
Annual discharge/charge	**TWh**	4.24	4.98
Load factor		25.4%	
Peak	**GW**	1.9	1.9
Standard deviation	**GW**	1.72	2.01

A major observation is that the charging of the battery is always carried out over long periods (at night) and the discharge intervenes in a less regular fashion in function of the market prices during hours when Switzerland is exporting.

Use of VRE generation curtailment as flexibility lever

VRE curtailment is not a permanent flexibility resource, but a form of generation that has to be curtailed during hours of excess generation from VRE and relatively low demand. This consists of the temporary disconnection of solar PV or wind capacity from the grid. The particularity of VRE is that its production is concentrated in a relatively limited number of hours, when large amounts of VRE capacity produce peaks that can no longer be absorbed by consumers, even including the load demand of flexibility providers such as hydro pumps or batteries. Not surprisingly, in the Swiss context, peak shaving is a phenomenon limited to the case of autarchy. In cases where the interconnection capacity is 100% or 50% of current levels, the low-cost VRE output of Swiss solar PV installations can still be exported to neighbouring countries. Curtailment is an economic loss because the potential output remains unused and the capital costs of the VRE are amortised over fewer hours.

Figure A8. **Profile of the VRE curtailment in the case of a VRE only strategy in Autarchy for the last two weeks of May and the full year**



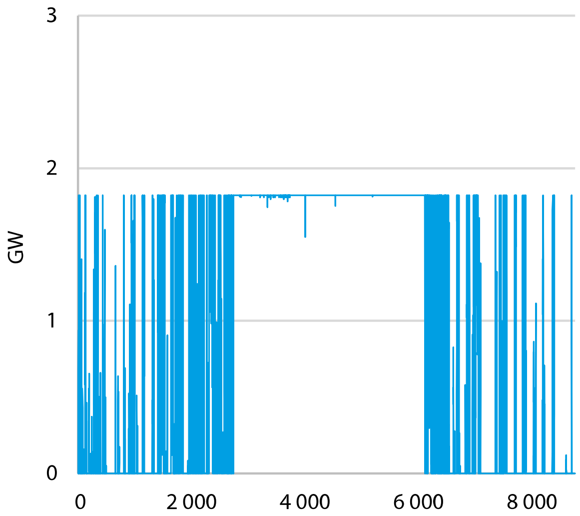
VRE capacity	**GW**	35.2
Annual VRE production	**TWh**	41.30
Annual VRE curtailment	**TWh**	2.83
Percentage of annual curtailed VRE production		6.8%
Curtailment peak	**GW**	11.08
Average curtailment	**GW**	0.32
Curtailment standard deviation	**GW**	1.30

As intuitively expected in Figure A8b, curtailment occurs during periods of high VRE production, i.e. in summer time when production is driven by high solar PV. Daily production patterns, shown in Figure A8a, emphasise the phenomena as the reduced production happen during the hours of the day, when the sun shines and solar PV operates. In the case of autarchy with a high share of variable renewable production, the other generation and flexible sources, are already operating at these constrained momentum, as shown above. In addition, the production is not exportable to neighbouring countries to take advantage of it, there remains only this more expensive option; curtailment. Nevertheless, a maximum of 30% of the total VRE capacity is curtailed and not the whole production, which could be a result of bad optimisation.

Hydrogen production as a flexibility acting on domestic demand

Low-carbon hydrogen production will serve both as a material input and as an energy vector in industry, and for some residential applications. It will complement direct electrification as a complementary, indirect form of demand. Many studies and experts agree that the world and more specifically Switzerland will produce sizeable amounts of hydrogen for industrial purposes and residential end-uses by 2050. In the study, it is assumed that 8 TWh of electricity in addition to the domestic demand will be used for the generation of hydrogen on the basis of water electrolysis with the help of proton exchange membrane (PEM) electrolysers. Even if all hydrogen is subsequently used directly as a chemical feedstock or in fuel cells without re-injection into the electricity system – for instance to drive a hydrogen-powered turbine – hydrogen production remains an important source of flexibility. Hydrogen production works to some extent like an extremely flexible demand; indeed, variable costs of H_2 production are set by the cost of electricity at the time of use. The PEM electrolysers are highly flexible and can thus be switched on hourly during times of excess supply and switched off during times of high demand. The flexibility contribution of the electrolysers can be identified very clearly in Figures A9 and A10 for two cases. For example, the scenarios with higher flexibility needs, typically the VRE only in autarchy scenarios, has higher electrolyser capacities than the LTO with full interconnection capacity.

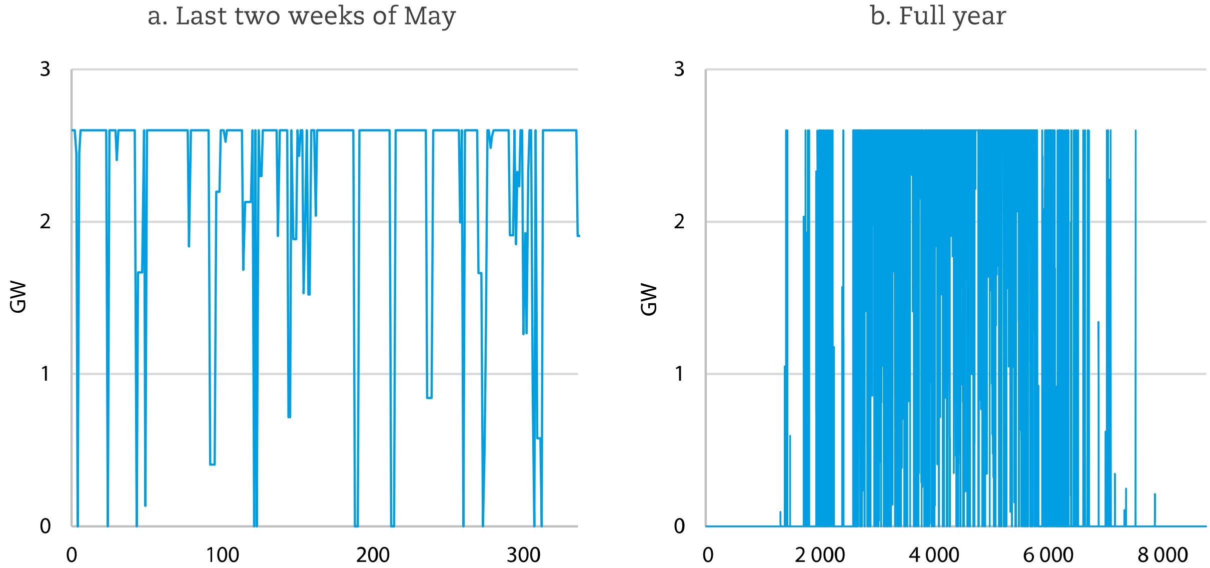
Figure A9. **Profile of the Hydrogen production in the case of a LTO with 100% interconnection for the full year**



Capacity	**GW**	1.8
Annual consumption	**TWh**	8.0
Load factor		50.7%
Production peak	**GW**	1.82
Average production	**GW**	0.91
Turbining standard deviation	**GW**	0.88

System optimisation will ensure that larger flexible capacities are operated over fewer hours to produce the 8 TWh worth of hydrogen, therefore both capacity of electrolysis as well as the production time of the hydrogen production are optimised. There is thus a trade-off between the higher fixed costs of the electrolysers and their flexibility contribution. The "flexibilisation" of the electrolysis not only reduces the installed electrolysis capacity but considerably increases the total flexibility of the system and thus further decreases the costs, in particular in the case without interconnection. Indeed, the hydrogen production profile which reflects the demand for electricity (see Figure A10) is constantly changing during summer time while zero in winter. Conversely, in scenario with full interconnection capacity, electricity demand for H_2 production is continuous, notably throughout the summer period.

Figure A10. **Profile of the Hydrogen production in the case of a VRE only strategy in Autarchy for the last two weeks of May and the full year**



Capacity	**GW**	2.6
Annual consumption	**TWh**	8.0
Load factor		35.1%
Production peak	**GW**	2.60
Average production	**GW**	0.91
Turbining standard deviation	**GW**	1.19

Summary

In conclusion, the use of a flexibility solution depends largely on the available tools in the considered scenario but this relies especially on a cost trade-off between the different technologies during the optimisation phase. For example, the VRE curtailment or the addition of batteries (because of its high investment costs) are only used as a last resort for the VRE scenario in autarchy where there are no alternative disptachable or flexible solutions (except hydro which may become a source of load-following rather than managing the uncertainty). In addition, the appendix highlighted that all flexibility providers participate in following the behaviour of solar PV, with a strong trend in the scenarios with 100% renewables, because in summer the demand for sources acting on the demand (pump hydro, H_2 prod, battery) increases as well as the use of skimming. On the contrary, flexible providers with relatively low costs are more solicited, with a lot of interconnection to benefit from the best European market prices.

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Achieving Net Zero Carbon Emissions in Switzerland in 2050: Low Carbon Scenarios and their System Costs

With an electricity system defined by high shares of hydropower, large capacity for interconnection with its neighbours and low carbon intensity, Switzerland is well positioned to attain its objective of net zero carbon emissions by 2050. However, the exact pathway remains the subject of discussion. First, what should the shares of nuclear energy and variable renewable energies such as solar PV and wind be in the energy mix? Second, what degree of electricity trade should Switzerland have with its European neighbours?

New system modelling of different energy policy choices with the Nuclear Energy Agency's POSY model shows that all considered scenarios are technically feasible. However, relying on variable renewables alone or decoupling Switzerland from neighbouring countries could increase total system costs by up to 250%. Instead, continuing to operate Switzerland's newest nuclear power plants alongside existing hydropower resources, while maintaining interconnection capacity at current levels, emerges as the most cost-effective option to achieve net zero emissions in 2050. Ample data and technical documentation of a least-cost mixed integer (MILP) modelling with hourly resolution are also provided in order to allow replication, extension and discussion of this study's findings.

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