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Thrive in sunshine, brace for thunder

Least-cost robust power system investments under political shocks

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Abstract

Energy system planning literature often focuses on either normal operating conditions or on shock/restriction scenarios. Systems designed only for normal years struggle during crises like fuel shortages or trade restrictions, leading to lost load or high prices, while systems optimized entirely for shocks can result in overinvestment in generation technologies with high capital costs. In this paper we address this limitation by incorporating both normal years and shocks in one single optimization model, using a partial equilibrium electricity market. Using Switzerland as the case study, we demonstrate how varying the severity and frequency of shocks affects the optimal technology mix. In the case of Switzerland, robust planning of the generation mix becomes crucial only at trade capacity reduction of more than 70%. When gas import is unavailable during the shock period, liquid fuel becomes optimal in severe trade capacity reduction by 90% or full autarky happening from once in 100 years to once in 10 years. As the frequency of these shocks increase, higher CAPEX technologies, such as renewables, become more favourable, with nuclear emerging as a viable option only if these severe shocks happen every other year. Our findings underscore the importance of balancing cost-efficiency with system resilience to ensure robust energy planning, capable of thriving in normal conditions whilst bracing for stressed conditions.

Keywords: System Adequacy, Robust Planning, Energy system resilience, Numerical modelling

1 Introduction

The global quest for decarbonization is driving a fundamental shift in the design and operation of power systems. Historically, power systems were built around a mix of dispatchable generation capacities, such as coal, gas, or nuclear plants. In contrast, modern systems are built around integrating increasing shares of renewable energy sources (RES) resulting in a growing importance of system flexibility. Today's systems must balance renewable generation, system flexibility measures and dispatchable capacities to meet peak residual load—the remaining demand after variable renewable generation like wind and solar is accounted for (Darudi & Weigt, 2024). Given the variability of power supply that renewable energy technologies introduce, this requires more complex planning to ensure system reliability and resilience under both normal and stressed conditions.

An energy system is typically adequate under the conditions for which it was planned. However, the Russian invasion of Ukraine and the subsequent energy crisis have reinvigorated the debate on robust system planning (Fabra et al., 2022). In the literature, energy system planning is often approached in one of two ways: based on normal years (Federal Office of Energy, 2021) or focused entirely on shock/restriction scenarios (Mellot et al., 2024). Planning based only on normal years can leave systems vulnerable to crises like RES availability, fuel shortages, or trade frictions. Such a design will perform very well in normal years but may lead to excessively high prices or lost load under stressed conditions - which could have been avoided with a bit of adjustments on the design of the power system. On the other hand, basing system design entirely on shock scenarios can lead to overinvestment in capacity and an inappropriate mix of generation technologies. For example, planning under the assumption that a shock that reduces energy availability throughout the year will persist over the entire lifespan of a power plant may result in the selection of technologies with high capital expenditure (CAPEX) and low operational expenditure (OPEX). These technologies are suitable for continuous, long-term operation but may not be cost-effective if the shock occurs infrequently or with limited duration. In contrast, technologies with lower CAPEX and higher OPEX are more appropriate for peaking applications where they are used only during occasional, short-duration shocks. For instance, gas and oil peaker power plants represent an important low-CAPEX, high-OPEX option. In many countries, the storage facilities for liquid fuel or gas already exist and, in the long run, their conventional usage will likely be reduced due to decarbonization. They require only maintenance and minor adjustments to serve as backup generation during times of crisis in the future. Moreover, stored liquid fuel or gas can be CO2 compensated, either by storing renewable-based green fuel or by using them in combination with negative emission technologies such as direct air carbon capture and sequestration (DACCS). Given that the storage tanks are located within the boundaries of a country or union, a gas- or liquid fuel storage based approach may seem like a viable option in certain conditions of shock especially in periods of fuel or energy import limitations.

In contrast to the conventional system planning approach that is economically efficient for one given set of conditions, robust power system planning may be used, which considers both normal operation years and shock events in one combined optimization problem. When it comes to modelling the shock events, we argue that both the expected frequency of the potential shocks as well as their potential severity should be considered. This is because both elements affect the timing and duration of additional generation needed to optimize the system, which in turn affects the optimal choice of generation technologies particularly with respect to their CAPEX-to-OPEX ratio.

Accordingly, in this paper, we apply a stochastic model to efficiently design a power system that is robust to shocks under defined degrees of likelihood and severity. To this end, we develop a partial equilibrium dispatch and investment model of the European power system with a particular focus on the Swiss system whose generation investment decisions considers both normal system operations and given shock scenarios (Darudi, 2024). As shock events, we consider trade limitations between Switzerland and neighbouring countries with different levels of frequency and severity. The severity of trade limitation shocks is reflected by strongly reduced net transfer capacities (NTCs) for the shock scenarios. Furthermore, we consider limitations on gas imports and different levels of renewable support. We then compare the contribution of different generation technology options to the security of supply under various shock scenarios. It is important to highlight that the scenarios investigated in this paper are stylized and both the likelihood as well as the severity numbers are illustrative, i.e., this paper aims to shockase the effect of the robust systems design approach rather than concretely recommend future system designs.

The key findings of this study highlight the strong relationship between the severity and frequency of shocks and the optimal investment in different technologies. When gas imports are unavailable during shock years, liquid fuel plays a critical role in severe scenarios with NTC reductions between 90 and 100 percent for the full year and shock frequencies of every 100 to every 10 years. As the frequency of shocks increases, higher CAPEX-to-OPEX ratio technologies become more viable. Initially, renewable sources such as photovoltaics (PV) and wind are deployed to meet demand, but in the most frequent and severe cases (shocks happening every other year), nuclear power plants are introduced—though this is only observed when Switzerland's RES generation target is not enforced. However, when gas imports are allowed during shock years, single-cycle gas-fired power plants (SCGT) and combined cycle gas-fired power plants (CCGT) are used at low and high shock frequencies, respectively. This indicates that the availability of gas imports plays a crucial role in shaping the optimal investment and operational strategies for electricity systems under stress conditions.

In conclusion, considering both "sunshine" (normal) and "thunder" (shock) scenarios enables us to design energy systems that are both efficient and resilient. In energy policy discussions, it is essential to clearly define system risks and their likelihoods for which we aim to design a robust system. Without this clarity, we may either build systems that are too vulnerable by focusing on cost reduction or create overly robust systems that become too expensive to implement. Balancing efficiency with resilience to shocks is key to effective energy planning.

2 Background and Literature Review

Switzerland's electricity system depends on a combination of domestic generation and imports. Currently, the country consumes around 60 TWh of electricity annually, with hydropower serving as its main source of energy, i.e., about 60% of total generation. Historically, nuclear power also plays a significant role, providing around 35% of the country's electricity supply. In addition, smaller contributions come from renewable energy sources like photovoltaics (PV) and biomass. However, during the winter months, Switzerland typically relies on imports to meet the demand (Federal Office of Energy, 2024). More generally on the energy side, Switzerland is currently importing 73% of its energy needs¹.

Switzerland's Energy Strategy 2050² aims to decarbonize the energy sector, with a focus on electrification and a significant increase in renewable energy, particularly solar power. The country's nuclear power plants are expected to be decommissioned as they reach the end of their operational lifetimes. Although current regulations prohibit new nuclear investments, there are periodic debates on whether lifting this ban would enhance energy security (Bärenbold et al., 2024). According to Energy Perspectives 2050+³, hydropower is expected to remain a cornerstone of the energy mix by 2050. While the strategy seeks to reduce Switzerland's reliance on energy imports (targeting a drop from 73% in 2019 to 25% by 2050), some imports, particularly of electricity, will still be necessary during critical periods like winter to ensure supply security (Federal Office of Energy, 2021). Achieving the strategy's ambitious goals of reducing energy consumption and boosting renewable energy production will require considerable infrastructure investments and strong collaboration with neighbouring countries.

One challenge Switzerland faces is its connection to the European Union's electricity market, given that Switzerland is not a member of the EU. Although it is centrally located within Europe's electricity grid and actively participates in cross-border trading, the absence of updated agreements with the EU puts Switzerland at risk of exclusion from future developments in the European energy market. While both parties benefit from this trade, some stakeholders in Switzerland are concerned about maintaining secure access to electricity imports, especially during high-demand winter periods.

Several studies have investigated the development of the electricity and energy sector in Switzerland. The Swiss Federal Office of Energy (SFOE) regularly conducts "System Adequacy" studies to assess the resilience of the electricity sector, exploring a wide range of scenarios related to both Swiss and EU developments (Weigt et al., 2020, 2022). These studies aim to identify the conditions under which lost load may occur in Switzerland. However, they treat supply-side capacities as fixed and do not model the potential impacts of elevated prices during periods of lost load on both supply and demand-side dynamics. In contrast, several other studies have allowed investments in the power system. For

¹ <u>https://www.bfs.admin.ch/bfs/de/home/statistiken/querschnittsthemen/monitoring-legislaturplanung/alle-indikatoren/leitline-3-sicherheit/energieabhaengigkeit-vom-ausland.html</u> Available Online, Accessed on 19.08.2024.

² Energy Stragety 2050 is Switzerland's official energy policy framework developed by the Swiss Federal Council. It was passed into law through the Energy Act (Energiegesetz) and other supporting legislation. It became law after being accepted in a public referendum held on May 21, 2017.

³ Energy Perspectives 2050+ is a strategic framework developed by the Swiss Federal Office of Energy (SFOE) to guide Switzerland's long-term energy transition. It builds upon earlier plans, such as the Energy Strategy 2050, with an extended vision that looks beyond 2050.

instance, as part of the SWEET CROSS project⁴, various techno-economic energy system models compared their results across identical scenarios, exploring the implications of developments in international energy markets and trade (Marcucci et al., 2023). On the other hand, a recent study specifically investigates generation technology options to ensure that Switzerland's winter imports remain below 5 TWh (Mellot et al., 2024). Importantly, each one of the results in these studies simulate system outcomes based on one predefined scenario, whereas our approach considers multiple potential scenarios within each simulation.

In our paper, we employ scenario-based programming as a method to model uncertainty in planning, which is a specific technique within the framework of stochastic modelling. Scenario-based analysis involves generating a finite set of distinct scenarios that represent different potential outcomes of uncertain parameters, such as the occurrence of a shock, following known probability distributions. The optimization problem is then formulated to minimize expected costs or maximize expected utility across all scenarios, taking into account the probabilities of each scenario. This method enables decision-makers to assess the robustness of different strategies, offering insights into which options are likely to perform well across a range of potential futures. For similar applications of stochastic optimization methods in the context of operation and planning of energy and power systems, see (Collins et al., 2017; Seljom & Tomasgard, 2015; Usher & Strachan, 2012); for a review on methods of modelling uncertainty in the power systems, refer to (Haugen et al., 2023).

Studies employing the scenario-based approach often incorporate multiple uncertain variables and ranges, leading to a large number of scenarios to analyse. To maintain computational feasibility, these studies typically necessitate "scenario generation" and "scenario reduction" as key components of their methodology.⁵ In contrast, our analysis concentrates on a single uncertain variable—the shock event—for each case. This simplified modelling approach allows us to clearly illustrate the concept and ensures that the findings are easily traceable, maintaining their political relevance for decision-making.

Finally, unlike previous studies, we recognize liquid fuel as a potential option for the future electricity system. The Federal Act on National Economic Supply mandates the storage of 3 to 4.5 months' worth of gasoline, diesel, heating oil, and aviation fuel within Switzerland, currently leading to a total tank capacity of approximately 6.6 million cubic meters (CARBURA, 2023). This resource may become available for other purposes in the future, as the Swiss energy strategy aims for decarbonization in heating and transport by 2050, which could reduce imports of certain fuels, and subsequently the associated storage needs. Importantly, these existing storage facilities do not require initial investment costs since they are already in place; only adjustment and maintenance costs would be necessary for adaptation to electricity generation. Additionally, being located within Switzerland, these storages provide a buffer against fuel import shocks, enhancing the resilience of the power system.

⁴ https://sweet-cross.ch/ Available Online, Accessed on 19.08.2024.

⁵ For a review on the application of scenario-based analysis in the planning and operation of power systems, refer to (Li et al., 2022).

3 Methodology & Data

For this study, we use the Future Electricity Market Model (FEM). FEM is a comprehensive technoeconomic model designed to simulate the investment, dispatch, and trade dynamics within the power systems of Switzerland and Europe. FEM operates as a partial equilibrium model of the wholesale electricity market, minimizing total system costs while adhering to a wide range of technical constraints. It provides projections of capacity mix, hourly prices, generation profiles, storage dispatch, flexible consumption, and cross-border electricity trading across different market areas. With an hourly resolution over a year and a specific focus on the Swiss power system, FEM allows investment decisions solely within Switzerland, while the rest of Europe follows predefined development scenarios taken from Ten-Year Network Development Plan 2022 (ENTSO-E & ENTSOG, 2022). Key features include the modelling of various renewable and conventional energy technologies, integration of storage systems, and incorporation of detailed electricity demand and trade constraints. In order to model the hydropower system realistically, the model follows a hydro calendar year, i.e., the model starts at the beginning of October.

The model covers new renewable energy sources comprising photovoltaics (PV), onshore wind, and offshore wind. The hourly generation profile is limited by weather-dependent and exogenously defined availability factors. The generation can be curtailed without a cost. In addition, the model includes the following conventional thermal technologies: nuclear, combined cycle gas turbines – CCGT, simple cycle gas turbines – SCGT, bioenergy-fired power plants (i.e., biomass), gas-fired CCGT with CCS, CCGT and SCGT plants using green methane as fuel, and liquid-fuel (oil). Additionally, the model incorporates various hydropower technologies, including run-of-river, dam plants, closed-loop pumped storage, and open-loop pumped storage systems. The hydro power capacities are also fixed to predefined scenarios. The model includes other storage options such as lithium-ion batteries and hydrogen-based storage systems that is modelled as a power-to-hydrogen-to-power closed loop. For a detailed description of FEM formulation and input data, please refer to (Darudi, 2024). Main cost assumptions of the model are included in the Appendix.

In the FEM variant developed for the current research, the objective function is adjusted to minimize the total *expected* investments and operations costs across various scenarios. A set of *Scenarios* are exogenously defined with given frequencies⁶ denoted as *weight_s*, whose value ranges between 0 and 1 and the sum for each simulation is equal to 1. This modified objective function balances the trade-offs between capital investments in generation and energy storage capacities, operational costs of running the power system, and the costs associated with unserved energy (lost load). The minimization occurs over all possible scenarios, with the operational costs of each scenario weight*s*. The optimization problem can be simplified as follows:

⁶ While these weights can be interpreted as probabilities, we prefer to interpret them as frequencies, which provides a more tangible perspective on how often certain scenarios may occur. Frequency-based interpretation expresses weights as expected occurrences within a specific timeframe. For example, a weight of 1/10 indicates that a shock scenario happens once in every 10 years.

 $Minimize: \sum_{p \in P_{allinv}} (inv_cost_genmax_p \times gen_max_p + inv_cost_enmax_p \times en_max_p)$

+
$$\sum_{s \in Scenarios} weight_s \times [$$

 $\sum_{p \in P_{gen}} \sum_{t \in T} (op_cost_{p,s} \times gen_{p,t,s})$
 $\sum_{t \in T} lostload_cost_t \times lostload_{t,s}]$

s.t.: constraints of scenarios $\forall s \in Scenarios$

The first term in the objective function accounts for the capital investments in both generation capacity gen_max_p and energy storage capacity en_max_p . The term $inv_cost_genmax_p$ represents the investment cost for generation capacity of the plant **p**, while $inv_cost_enmax_p$ represents the investment cost function for energy storage capacity of plant **p**, if applicable. These costs are summed over all potential investment options, i.e., various generation and storage technologies.

The second term captures the operational costs of generating electricity and lost load cost. $op_cost_{p,s}$ is the linear component of the operational cost for generation unit p in scenario s and $gen_{p,t,s}$ represents the actual power generation by unit p at time t in scenario s. These operational costs are weighted by the scenario likelihood and summed across all scenarios and time periods. Within each scenario, the operational constraints should be considered.

In our analysis, we will conduct several case studies, each uniquely defined by a specific *severity* of a shock and the *frequency* at which that shock occurs. For each case study, we establish two scenarios: a benchmark case and a shock case. The benchmark scenario represents normal market conditions, where there are no shocks. Conversely, the shock scenario is characterized by Switzerland having limited electricity import capacity. More precisely, in a shock year, only a certain percentage electricity trade capacity (NTC) is available. In these case studies, we assume that the shock scenario occurs once in N years, while all other years N - 1 years follow the benchmark normal conditions. This approach allows us to explore how different energy systems might respond under both regular and stressed conditions.

On the shock *severity* dimension, we analyse a range of shock scenarios covering NTC of 0%, 10%, 25%, and 30% of the usual cross-border electricity trade capacity. The 0% NTC represent an autarky case in which Switzerland will be forced to not import/export electricity throughout every hour of the year. Depending on the details of the case study definitions, fuel import may or may not be possible. These cases are deliberately chosen to represent extreme and very harsh conditions in terms of energy trade limitations.

On the shock *frequency* dimension, we examine how often these shocks occur by considering a variety of occurrence intervals: once in 1000, 100, 10, 5, and 2 years. This range of frequencies allows us to evaluate the resilience of the system under both very rare and relatively frequent disruptions to cross-border electricity trade.

It is important to note that we do not pass judgment on whether policymakers should consider any particular case. Instead, the goal is to provide a comprehensive framework that allows readers and policymakers to choose the scenarios they find most relevant or worth exploring further.

We divide our analysis to two subparts. In the "main" analysis, we focus on the case in which Switzerland do not implement any support policy for RES generation and cannot import fuel in the shock year (No RES target – gas import not allowed). In addition to the main cases outlined above, we also examine three alternative sensitivity cases. The first sensitivity case, "No RES target – gas import allowed," is similar to the main analysis, but with one key difference: during shock years, gas imports are permitted. The other two sensitivity cases, "45 TWh RES target – gas import not allowed" and "45 TWh RES target – gas import allowed," assume that Switzerland has implemented renewable energy support policies for photovoltaics (PV) and wind, to the extent that total installed capacities would potentially lead to renewable generation of 45 TWh (ignoring possible curtailments). In the "45 TWh RES target – gas import allowed" scenario, gas imports are permitted. We also include two single simulations called the "Reference" cases that represent system planning ignoring any shocks to be used as point of reference for comparisons (more details in Section 4).

	NTC limit	Gas import limit	RES support target
Reference	No	No	No
Reference with 45 TWh RES target	No	No	Yes – 45 TWh
Main: No RES target – gas import not allowed	Yes (shock year)	Yes (shock year)	No
No RES target – gas import allowed	Yes (shock year)	No	No
45 TWh RES target–gas import not allowed	Yes (shock year)	Yes (shock year)	Yes – 45 TWh
45 TWh RES target – gas import allowed	Yes (shock year)	No	Yes – 45 TWh

Table 1 Description of the benchmark case and case studies

4 Results and Discussion

In this section, we define the Reference runs, which include scenarios without any shocks. These baseline cases serve as a benchmark to which we compare the results of our analysis. Following this, we analyse the relative system performance under different shock scenarios. We then conduct a per-technology analysis, summarizing when each technology is utilized across different cases. Lastly, we address the model's limitations, discussing key aspects that should be considered when interpreting the results.

4.1 Reference cases

We run the simulations for the year 2050. We consider weather year of 1995, which is considered as the representative of an average year from climactic perspective in TYNDP 2022 data set. Figure 1 illustrates the annual balance of consumption and generation in Switzerland for the Reference case (no RES target, no shock, and gas import allowed). Given that the import is allowed, the system optimizes by importing as much electricity as possible from neighbouring countries, with total imports amounting to 35.15 TWh. Such level of imports is admittedly unrealistic e.g., from political and social acceptance perspectives. Naturally, if lower investment costs, renewable generation support, higher electricity generation costs or lower generation capacities in neighbouring countries were assumed, domestic generation investments within Switzerland would be higher. However, we maintain this case as the reference case as it provides a consistent baseline for comparison. By using this reference, we can clearly highlight how trade-limiting shocks will drive additional investments in domestic generation within Switzerland in contrast to this completely unrestricted scenario.

In the Reference case, the demand is met by a combination of domestic generation and net imports. Photovoltaic (PV) generation contributes 6.0 TWh, while wind provides a smaller portion at 0.6 TWh. The largest domestic source of generation comes from hydropower, which is divided into three categories: run-of-river (RoR) with 17.4 TWh, dam and open pump storage contributing 15.4 TWh, and closed-loop pump storage adding 1.33 TWh. The total annual conventional demand amounts to 76.0 TWh. Additionally, 4.8 TWh is consumed by storage technologies such as pump storage and battery systems. There is no energy consumption for hydrogen production, nor is there curtailment of renewable energy sources in this scenario. Nuclear, CCGT RES methane, SCGT RES methane, CCGT with CCS, SCGT fossil, hydrogen, and liquid fuel do not contribute to generation in this scenario. Additionally, the reference case leads to zero load shedding. While analysing results of the main cases (No RES target – gas import allowed), we compare annual generations with this Reference case.

Figure 1 also illustrates the annual balance of consumption and generation in Switzerland under the Reference case with a 45 TWh RES target (also with no shock). The main difference to the reference case is that PV generation increases significantly, which exceeds 44 TWh, accompanied by a rise in curtailment, which reaches 2 TWh. In the sensitivity analysis, we compare each group of cases with the corresponding Reference run.



Annual Generation/Consumption Balance

Figure 1 Annual generation and consumption balance in Switzerland for the reference case.

4.2 Main case (no RES target - gas import not allowed in the shock year)



Figure 2 The main case (no RES target – gas import not allowed in shock year): extra generation (per technology) used in the shock year.

Figure 2 represents the dispatch outcomes for different cases under shock scenarios in the main analysis. In this graph, we focus only on the investment/dispatch dynamics in the shock year (the normal years' dispatch values are not shown). The graph covers 20 cases, which are the combination of 4 different levels of trade limit shocks (NTC) and 5 different frequencies of the shock occurring. The x-axis indicates how often the shock occurs (every N years), and the y-axis shows the severity of the shock, with increasing severity from bottom to top. Each box in the graph corresponds to one system design, and within each box, the amount of extra annual generation (compared to Reference case) by different technologies or the energy not served (compared to the reference case) is displayed in a stacked format. A fully stacked box represents 36 TWh of generation. For example, the top-left box represents the scenario where Switzerland experiences complete autarky (NTC of 0 and no gas imports), occurring once in 1000 years. In this severe and rare case, the model identifies load shedding (lost load) of around 34 TWh as the optimal solution.

The results suggest that in cases where NTC is limited to 30% (70% reduction in trade capacity), the model does not justify extra investments. Despite hourly import restrictions, Switzerland's flexible hydropower system and import capacity still allow enough imports to cover the demand. However, the import pattern will be different in the shock year. On the other hand, lost load is only considered in the model for the extremely infrequent scenario where the shock occurs once in 1000 years.

In most scenarios with shocks occurring every 100, 10, or 5 years and an NTC limit between 0% and 25%, a combination of extra generation from liquid fuel and renewable energy sources (RES) is necessary to meet consumption needs. At lower frequencies, such as once in 100 years, liquid fuel is favoured due to its low investment cost, despite high operational costs linked to CO2 emissions. This is because the plants are used so infrequently that high operational costs are less significant throughout the lifetime of the plant. As a result, in the cases where the NTC shock is 0% or 10% and occurs once in 100 years, liquid fuel generation is almost fully utilized, up to the model's limit of 24 TWh, reflecting Switzerland's existing liquid fuel storage capacity.⁷ As the frequency of shocks increases, the system shifts toward more reliance on renewable energy generation to avoid the high operational costs of liquid fuel plants.

Hydrogen based electricity storage is used only in NTC 0 case with frequency of every 5 years, generating around 1.4 TWh of electricity. In more frequent cases (NTC 0 happening every other year), nuclear plants are preferred choice compared to hydrogen-based electricity storage. Nuclear power plants become a viable option only in extreme and frequent shock cases, such as when the NTC is 0% or 10%, and the shock happens every other year.

 $^{^{7}}$ 24 TWh is calculated based on assuming all 6.6 million cubic meters of storage tanks can be used to store oil having a density of density of 0.9 kg/liter, a heating value of 42 MJ/kg, a conversion rate of 1 MWh to 3600 MJ, and a power plant efficiency rate of 35%.

4.3 Sensitivities

Now we turn our attention to the sensitivity cases. First, we examine the "No RES target – gas import allowed" case, which is essentially the same as the main case, except that gas imports are permitted during the shock year.



Figure 3 The case of no RES target – gas import allowed in shock year: extra generation (per technology) used in the shock year.

As shown in Figure 3, this scenario leads to much less lost load compared to the main cases. The system finds only 3 TWh of lost load to be optimal in the cases with the least frequency of happening (once in 1000 years), while in the same frequency of the crisis happening, the main cases decided for up to 34 TWh. Instead of resorting to lost load, the model identifies investments in liquid fuel power plants, simple cycle gas-fired power plants (SCGT) and combined cycled gas-fired plants (CCGT) as the optimal solution. The system fully utilizes its gas import capacity during the shock year and, when necessary, turns to more expensive liquid fuel plants to avoid energy shortages.

In highly severe shocks, such as NTC of 0% and 10%, as the likelihood of the shock increases, combined cycle gas-fired power plants with carbon capture and storage (CCS) become a more favourable option compared to SCGT plants. While CCS plants have high investment costs, their operational costs are lower compared to other gas-fired plants, making them a viable choice for more frequent shocks. Additionally, investments in high-capex, zero-operating-cost renewable energy sources like photovoltaics (PV) and wind generation also increase under these conditions.

Interestingly, when gas imports are available, nuclear plants are not utilized in any of the studied combinations, indicating that the availability of gas as an alternative fuel source removes the economic incentive to invest in nuclear generation.

Now we turn to the sensitivity cases with the 45 TWh renewable energy (RES) target, specifically focusing on the "**45 TWh RES target – gas import not allowed**" scenario. Figure 4 shows the sources of extra generation (compared to the Reference case with 45 TWh RES target) in the shock years for this case. In the very infrequent case where the shock occurs only once in 1000 years, the unavailability of gas leads to lost load in the most severe scenarios—NTC limits of 0% and 10%. However, compared to the main case (without the RES target), the amount of lost load is significantly reduced when the RES target is applied. For instance, in the main scenario, an NTC of 0% with a shock frequency of once in 1000 years led to 34 TWh of lost load. In contrast, with the RES target (and no gas availability), the lost load in the same case is reduced to 10 TWh. Of course, this reduction comes at the cost of high investments needed to achieve the 45 TWh of potential RES generation in the first place.

In the extreme and frequent case of NTC 0% occurring every other year, the system avoids lost load through a combination of additional wind investments (an extra 7 TWh, which reaches the assumed wind generation potential limit in Switzerland), 2.5 TWh of electricity generated from the hydrogen loop, and 5 TWh of nuclear generation. Compared to the main case, reliance on nuclear power has decreased (from 15 TWh to 5 TWh) due to the higher share of RES generation, as well as the increased viability of hydrogen generation in a scenario with a high share of RES and no export/import possibilities.

For NTC limits of 10%, in the frequency range between once in 100 years and once in 2 years, a mix of liquid fuel and wind generation is used to achieve energy balance. In comparison to the corresponding scenarios in the main case, these scenarios require lower amounts of liquid fuel and extra RES investments, as already a high share of RES generation is applied to the system.

In the case of NTC 25%, no additional investments are needed in this sensitivity, unlike in the main case where a small amount of investment was still required under the same conditions. This suggests that with a higher share of RES, the energy system is more resilient to trade constraints at this level of NTC. However, as mentioned earlier, this has been achieved by already investing in high amounts of RES generation capacities.

Now we analyse the "**45 TWh RES target – gas import allowed**" case. As shown in Figure 5, in this scenario, we still observe lost load in the NTC 0 and 10% at the frequency of 1000 years. However, compared to its counterpart without gas availability, in this scenario the SCGT plants play a more important role at the frequency of once in 100 years. As the frequency of the shock increases, the system primarily relies on CCGT plants with CCS (in the NTC 0 case) and additional wind generation (in the NTC 10% case) to balance generation and consumption.



Figure 4 The case of 45 TWh RES target – gas import not allowed in shock year: extra generation (per technology) used in the shock year.



Figure 5 The case of 45 TWh RES target – gas import allowed in shock year: extra generation (per technology) used in the shock year.

4.4 Per-technology overview

Liquid Fuel: In most scenarios where gas is not available during a shock happening at higher frequencies (every 100, 10, or 5 years) and NTC is between 0% and 10%, liquid fuel plants are employed, particularly because of their low investment costs. Although they have high operational costs due to CO2 emissions, their infrequent use makes them an optimal solution for meeting energy needs. In extreme cases like NTC 0% with a shock frequency of every 100 years and gas import unavailability, liquid fuel generation is fully utilized, up to the model's limit of 24 TWh, reflecting Switzerland's storage capacity. As shock frequency increases, the system shifts towards other high CAPEX low OPEX technologies rather than liquid fuel.

Renewable Energy Sources (RES): As the frequency of shocks increases, the system gradually increases its reliance on RES. In cases of severe shocks with high frequency, wind generation becomes especially favourable, often utilized up to the maximum allowed potential in Switzerland. In scenarios with the 45 TWh RES target, the reliance on renewable energy generation increases even more. This target significantly reduces lost load, even in severe cases. For instance, with the RES target, lost load in the case of NTC 0% with a shock frequency of once in 100 years drops from 34 TWh in the main case to just 10 TWh. However, achieving this reduction comes at the cost of substantial upfront investment in renewable energy infrastructure.

Nuclear Power: Nuclear plants become a viable solution only in extreme cases with frequent shocks (such as full autarky or 90% trade reduction happening every other year). However, in scenarios where gas is available, nuclear power is not used at all, as gas becomes the more economically favourable option (joint by RES investments).

Gas-fired Power Plants: When gas imports are allowed, the system opts for simple gas-fired power plants as a solution to avoid lost load. SCGT is used for infrequent shocks, while CCGT with carbon capture and storage (CCS) becomes more favourable in high-frequency shocks due to its lower operational costs. The availability of gas imports reduces the reliance on more expensive technologies like nuclear and hydrogen.

Hydrogen Storage: Hydrogen-based electricity storage plays a minor role, with limited use only if gas is not available during the most severe scenarios (NTCs of 0) occurring at frequencies of every 10, 5, and 2 years. In these cases, hydrogen generates at a maximum of 2.5 TWh of electricity. The role of hydrogen storage for electricity generation disappears when gas imports are available, highlighting its significance only in scenarios where other fuel sources are limited.

4.5 Limitations

Several limitations of this study should be noted. For example, we do not make any assumptions about whether firms can anticipate such shocks in the electricity market. As a result, we are not making any claims about whether an Energy-Only Market (EOM) is sufficient on its own, or if additional mechanisms such as a capacity market would be necessary to achieve the presented robust generation mix.

Additionally, we assume that Switzerland's entire liquid fuel storage capacity is dedicated to electricity generation. If a portion of this storage is allocated to other uses, the available capacity for electricity production would be reduced, potentially impacting system reliability. It is also important to note that in the model, all stored liquid fuel is fully depleted by the end of the shock year, which may not reflect operational realities where some reserves might need to be conserved for future periods, especially if the shock is expected to last multiple years.

The model also uses a single weather year, which may not capture the full variability of conditions, especially for hydropower generation. Dunkelflaute periods may be considered in the extensions of the model. Moreover, hydropower plays a particularly crucial role in Switzerland's energy mix. Since inflows to hydropower reservoirs can vary significantly from hydro year to hydro year, future work should incorporate multiple weather years to account for this variability and better reflect the uncertainties in water availability.

The model does not account for fuel-switching power plants, which could be a valuable flexibility measure during shocks. Including such plants in future analyses could provide more comprehensive insights into the potential for adaptive generation strategies during times of restricted fuel availability.

Finally, the results presented in this study are inherently sensitive to the assumptions made within the model, particularly regarding investment and operational costs of different technologies. Variations in these cost assumptions may influence the optimal technology mix.

5 Conclusion and Policy Implications

In energy policy debates, potential risks to the system and their likelihood should be clearly defined. Otherwise, systems end up being designed to be either cheap to build but ignoring potential risks or systems that are robust to risks but too expensive to be built. Considering both the "sunshine" and the "thunder" cases simultaneously allows for identifying system planning results that are both efficient and robust to shocks. Most importantly, technologies that serve as an insurance for high severity, but low frequency risks are characterized by comparably lower CAPEX and higher OPEX.

This study highlights the potential of liquid fuel power plants as a key component in designing robust power systems for various shock scenarios. Switzerland possesses a substantial tank fleet for liquid fuel storage, which may remain underutilized by 2050 as the country transitions to a decarbonized energy system. If gas imports are unavailable during shock years, liquid fuel power plants may become a critical resource, especially in severe scenarios with net transfer capacity (NTC) reductions of 90-100% and shock frequencies ranging from once in 100 to once in 10 years. As shock frequency increases, renewable sources are initially favoured to meet demand, but in the most frequent and severe cases—90 to 100% NTC reduction every other year—nuclear power is introduced. In contrast, when gas imports are allowed during shock years, the system predominantly relies on single-cycle gas-fired power plants at lower shock frequencies and combined cycle gas-fired plants with CCS at higher frequencies.

The definition of scenarios in this study can be further refined and expanded. Currently, we focus solely on net transfer capacity (NTC) limitations with predefined constraints on gas availability. However, other

types of shocks, such as specific import restrictions during winter months, could also be considered to capture more seasonal variations and vulnerabilities in future work. Given the vast number of potential scenarios and shocks, it is essential to carefully define the space of shocks to be analysed. Given the importance of energy supply security to a wide range of stakeholders, including policymakers and the general public, scenario definition should be done in close coordination with these stakeholders.

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6 APPENDIX

Technology	Lifetime (years)	Thermal efficiency	CAPEX (EUR/kW)***	O&M (EUR/MWh)	GHG Emissions (tCO2/MWh)	Data Source
PV	25	-	630.375	-	-	(Garrison et al., 2020)
Wind	25	-	1822.45	-	-	(Garrison et al., 2020)
Nuclear	50	-	10856.5	0.9	-	(Lazard, 2024)
CCGT with RES methane	25	0.53	876.375	1.67611	-	(Garrison et al., 2020)
SCGT with RES methane	25	0.35	717.5	1.67611	-	(Garrison et al., 2020)
CCGT WITH CCS	25	0.47	1537.5	1.67611	20.52**	(Garrison et al., 2020)
SCGT with fossil fuel	25	0.35	717.5	1.67611	205.2	(Garrison et al., 2020)

The Appendix presents the main cost assumptions of the model in Table A1, Table A2, and Table A3.

Liquid fuel	25	0.35	717.5	3.30546	300.6	(Garrison	et	al.,
						2020)		

Table A 1 Characteristics of generation technologies in which the model may invest.

* To have considered the fixed costs of maintaining the power plants (EUR/kW/year), the investment costs obtained from the sources are increased by 2.5%.

** Assuming a carbon capture rate of 90%.

*** The effect of construction duration on the investment cost is not modelled. Longer construction durations will increase the effective investment costs for a technology, which is particularly the case with nuclear power plants with long construction times.

Technology	Round trip efficiency	Lifetime (years)	Storage CAPEX (EUR/kWh)	Power CAPEX (EUR/kW)	Data Source
Battery	0.86	10	101.24	85.59	(Mellot et al., 2024)
Hydrogen Electricity Storage	0.4	15	9.22	1611.81	(Mellot et al., 2024)

Table A 2 Characteristics of the battery and hydrogen storage technologies.

Fuel (for)	Costs (EUR/MWh heat or EUR/tCO2)	Maximum annual import capacity (TWh heat)	
RES methane	198	18	(Mellot et al., 2024)
Fossil gas	18	36	(Federal Office of Energy, 2021)
Liquid fuel	2.2	69*	(Federal Office of Energy, 2021)
CO2 Price	397	-	(Federal Office of Energy, 2021)
CO2 transport and storage cost	80	-	(CCUS Projects network, 2021)

Table A 3Fuel and CO2 characteristics (costs and annual import limits) in 2050.

* The total current storage capacity in Switzerland, used as maximum storage capacity in 2050.

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