Switzerland’s winter energy gap:
The role of storage

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Abstract— **This paper presents a two-level stochastic model to determine Switzerland’s economically optimal energy storage investments. It also models and optimizes electricity trade with neighboring countries and the deployment of power plants while considering various demand-side management options like the flexible charging of electric vehicles or the flexible operation of heat pumps in buildings. The model is applied to both normal scenarios and shock scenarios, where electricity trade with the EU is significantly restricted. The paper focuses on analyzing Switzerland’s storage levels and cross-border electricity trading. The model runs for two future years. In 2035, it tends to reduce imports rather than exports as trading capacity decreases. By 2050, it saves more on exports while further cutting imports. In both years, storage depletion in winter slows under tighter trading limits, whereas with no extra constraints, the model depletes storage faster and compensates later through imports.**

Index Terms-- **energy storages, numerical modeling, future Swiss energy system, market design**

I. INTRODUCTION

With Switzerland’s goal to become carbon neutral by 2050, the ongoing energy transition is becoming increasingly tangible. In the electricity sector, nuclear power plants are being replaced by renewables, oil and gas heaters by district heating or heat pumps, and gasoline- and diesel-powered cars by battery-electric vehicles. However, these changes lead to different consumption and generation patterns that our current behaviors and habits are not yet adapted to. For example, wind turbines can have a feed-in to the grid at any time throughout the year anywhere between their minimal and maximal capacity, whereas solar power follows a daily sun-driven pattern, heavily influenced by the seasons and cloud cover.

To address these variations in generation, demand-side management (DSM) can play a crucial role by leveraging the newly gained flexibility in the consumption of electric vehicles (EVs) and heat pumps. However, ensuring a certain capacity of fast-response storage to balance electricity supply and demand on a day-to-day basis is essential. [1] Given that Switzerland is heavily affected by seasonal variations, the question arises whether additional measures are needed to manage the significant differences between, for example, photovoltaic (PV) feed-in and heat pump consumption during summer and winter. Large-scale seasonal storage could be necessary to ensure a reliable electricity supply year-round or could simply be economically beneficial. This issue should be analyzed, particularly in light of Switzerland’s well-established electricity grid connections to its neighboring countries.

Currently, extensive electricity trading occurs between Switzerland and France, Italy, Austria, and Germany. However, as Switzerland is the only country among these not part of the EU, there is ongoing uncertainty regarding trade agreements [2]. If negotiations were to fail and electricity trade with neighboring countries were restricted, additional pressure would be placed on the Swiss grid. For this reason, it is important to consider so-called shock scenarios that assume a reduction in net transfer capacities (NTCs) between Switzerland and its neighbors.

To address these challenges, this paper proposes a two-level stochastic model, building upon a model introduced in [3]. Multilevel stochastic modeling is a well-established approach in energy market analysis [4] [5] [6]. By introducing two levels to the model, optimal investment decisions can be determined at the upper level, applicable to all potential scenarios, while at the lower level, the operation of both new and existing plants is optimized. In a stochastic model, each scenario contributes to the objective function with a specific probability weight. This allows the model to account for shock scenarios, making appropriate investments to prevent costly load shedding in these cases, while still prioritizing the more probable normal scenarios. Consequently, shock scenarios should be assigned a significantly lower probability than normal ones, ensuring that the model remains optimized for typical years while still being adequately prepared for rare disruptions.

The model’s results can provide insights into the following aspects:

- **Optimal investments in renewables** beyond those mandated by expansion targets set by Swiss government policies.
- **Potential investments in fossil-fueled power plants** depending on the scenario year. In some cases, the model may still consider investments in combined-cycle gas turbine (CCGT) plants.
- **Investments in storage technologies**.

979-8-3503-8174-0/24/$31.00

- **Electricity trade with neighboring countries**, which can be artificially restricted to simulate shock scenarios.
- **Deployment of different technologies**, particularly storage technologies and their role in the system.
- **The behavior and impact of DSM** in heat pumps, EVs, and district heating systems, and their potential to reduce grid stress.

The version of the model presented in this paper is still a work in progress and will be completed in the coming weeks. However, the current version does not yet provide meaningful insights into economically optimal investment decisions. At this stage, the model is primarily used to analyze electricity trade with neighboring countries, the utilization of Switzerland’s large reservoir storage capacities, and the DSM potential of heat pumps and EVs.

II. FORMULATION OF THE MODEL

A. *Objective function*

The model employs a bilevel stochastic optimization approach to minimize overall system costs across multiple scenarios, each contributing with different weights to the objective function. The costs for each scenario consist of the following components:

- **Investment costs** for the technologies the model can choose to invest in.
- **Operational costs** for both existing plants and newly built plants in which the model chooses to invest. When the model decides to invest in a plant, it is assumed to be constructed and immediately available for operation. The inclusion of operational costs in the objective function ensures that the model optimizes the deployment of these plants.
- **Lost load costs** incurred if the model is unable to meet electricity demand. Since the cost of lost load is extremely high, the model typically invests sufficiently to reduce lost load to zero.

B. *Energy balance constraint*

The energy balance equation is a fundamental component of electricity market and power system optimization. It ensures that, at every node in the model and during all hours, total incoming energy equals total outgoing energy. Since this model includes the entire ENTSO-E area, each market zone is represented by its respective node.

The left-hand side of the energy balance equation represents incoming energy and consists of the following components: generation and feed-in from conventional, renewable, and storage plants, as well as imports from neighboring nodes and lost load. While lost load is technically not available electricity, it represents demand that the model chooses not to cover (at a high cost) and is therefore included to maintain balance in the energy equation.

The right-hand side of the equation represents outgoing energy and consists of: local demand at the node, energy charged into storage, exports to neighboring nodes, and curtailment.

C. *Storage balance constraint*

The storage balance constraint ensures that energy storage systems maintain the correct charge level at each node for every time step in the model. The stored energy at a given time depends on the previous storage level, the amount of energy charged into storage, and the amount discharged, while accounting for charging and discharging efficiency. Additionally, storage losses, which represent the energy dissipated over time, are deducted. This constraint applies to both electric and thermal storage systems.

D. *Households heat supply*

Households with heat pumps are considered for demand-side management (DSM). All households in Switzerland are categorized based on location, age, and size, and naturally lose heat according to outside temperature variations. The heat pumps must operate to maintain indoor temperatures within a predefined comfort range. The necessary data kindly has been contributed and stems from [7] [8].

Since electricity prices fluctuate, the heat pumps can strategically decide when to operate to minimize heating costs. The indoor temperature range is defined between 21°C and 23°C, ensuring comfort. To prevent the model from continuously heating at the lower limit to save energy, an additional constraint enforces an average indoor temperature of 22°C per week.

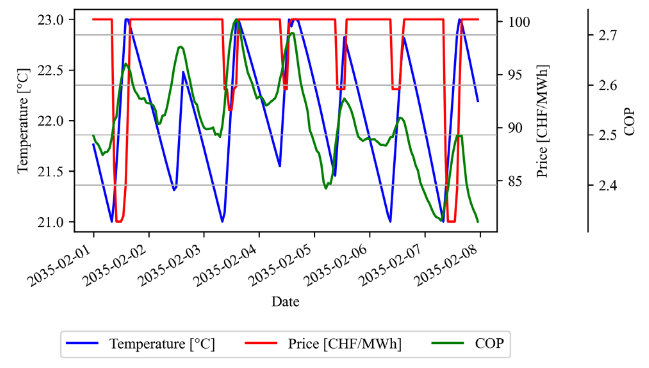

Figure 1. Temperature in a heavy, old building in the swiss midlands when controlled by a price driven heat pump.

Figure 1 illustrates the behavior of price-driven heat pumps operating in heavy, old buildings in the Swiss midlands. As expected, the model takes advantage of low-price hours to heat and raise indoor temperatures. At the same time, it accounts for the coefficient of performance (COP), which varies with the outside temperature. Between February 1st and February 2nd, the model prioritizes heating during hours when the COP is high, maximizing the heat pumps' efficiency. During these periods, the electricity price remains constant and therefore does not influence the heating decision.

E. District heating systems

Similar to households, district heating systems also have an hourly heat demand. However, they can utilize multiple competing technologies, such as resistive heaters, heat pumps, and CHP plants, to generate the required heat. Buildings connected to the district heating grid follow a predefined comfort temperature range, enabling demand-side management (DSM) similar to households with heat pumps. Additionally, the model can choose to invest in thermal storage systems to further enhance DSM potential. However, in the current version of the model, district heating is not yet fully operational and is therefore not applied.

F. Electric vehicles

Electric vehicle (EV) charging is also included in the model to account for its future DSM potential. For instance, [9] assumes that by 2050, half of all EV charging processes will be flexible over multiple days. As a result, the model can allocate this flexible share of charging demand on a weekly basis. The maximum hourly charging capacity is determined based on typical parking and driving patterns. For example, during the night, when most cars are parked and plugged in, the available charging capacity is significantly higher than in the evening, when commuters return home from work.

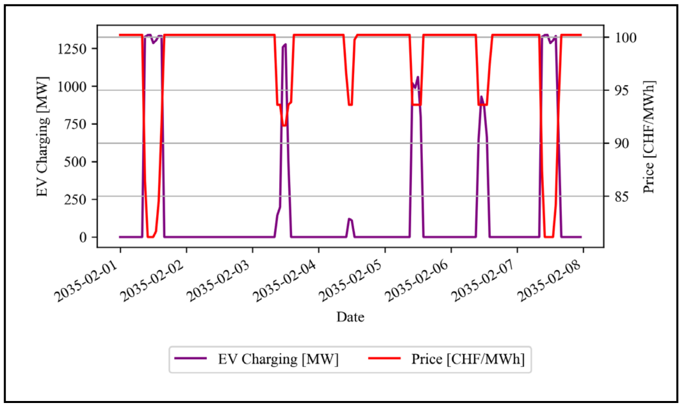

Figure 2. Price driven, automated charging behavior of EVs in the model.

Figure 2 illustrates the charging processes of the flexible-share EVs. As expected, most charging occurs during low-price hours at the beginning and end of the week. However, due to charging constraints that prevent excessive charging at once, the model also utilizes medium-price hours during the week to distribute the charging load efficiently.

G. Other constraints

To keep this paper at a reasonable length, the remaining constraints are not described individually but rather grouped and explained based on their intended effects.

Several constraints regulate the feed-in and consumption of all types of producers and consumers. For instance, no plant can operate beyond its capacity, and storage technologies must start and end at predefined levels to prevent the model from exploiting initial conditions.

Investment constraints limit the expansion of generation and storage capacities in different regions of Switzerland, and the net transfer capacities (NTC) between market zones are also restricted.

Additionally, optional constraints can be applied to further refine the model. These include limiting Switzerland's energy trading with neighboring market zones or enforcing a minimum installed capacity of renewable energy sources.

III. SCENARIO DESCRIPTIONS

The model runs for the years 2035 and 2050, analyzing the respective implications of the energy transition. To account for the expansion of the European electricity grid and the development of European countries in their energy transition, the model relies on ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2022 [10] and its Global Ambition scenario. The Global Ambition scenario assumes a transition driven by global efforts to meet the Paris Agreement targets, leading to the widespread adoption of renewable and low-carbon technologies and leveraging global energy trade to accelerate decarbonization.

For Switzerland's assumed developments, the model uses the Zero-Basis scenario from the Energy Perspectives 2050+ [9], whereas some adjustments regarding Switzerland's renewable expansion have been made by the modelers. This scenario explores how Switzerland can transition to a net-zero greenhouse gas emissions energy system by 2050 while maintaining a secure energy supply.

As described in the introduction, a key advantage of stochastic modeling is its ability to optimize across multiple subscenarios. From this point onward, a scenario is defined as a set of subscenarios that are optimized together in a single model execution. These subscenarios vary primarily in terms of Switzerland's net transfer capacities (NTCs).

For both 2035 and 2050, the following scenarios are defined and compared:

- Base Case: No stochastic modeling is applied, as only one subscenario exists, where NTCs remain unrestricted.
- Medium NTC Limitation: A more cautious outlook on the future. The unrestricted NTC subscenario occurs with an 80% probability, while in 20% of cases, NTCs are reduced to 50% of their base case capacity.
- Heavy NTC Limitation: A pessimistic perspective. The unrestricted NTC subscenario still occurs with an 80% probability, but in 20% of cases, Swiss NTCs are reduced to only 20% of their base case capacity.

IV. MODEL RESULTS

Table I compares Switzerland's imports and exports across the different scenarios. It is important to note that the subscenarios without NTC restrictions in the Medium NTC Limitation and Heavy NTC Limitation scenarios closely resemble the Base Case and are therefore not displayed in the following tables. In other words, only the subscenarios where an actual NTC reduction occurs are represented for the Medium and Heavy NTC Limitation scenarios.

TABLE I. TOTAL ELECTRICITY IMPORT (EXPORT IS NEGATIVE) FROM SWITZERLAND'S NEIGHBORING COUNTRIES FOR THE 2035 MODEL RESULTS.

TWh	Basecase	Medium NTC limitation	Heavy NTC limitation
Import AT	-9.1	-4.9	-2.1
Import DE	-36.4	-20.6	-8.6
Import FR	46.9	18.7	3.8
Import IT	-39.5	-21.1	-8.5
Total	-38.1	-27.8	-15.4

As shown in Table I, trade with all neighboring countries decreases significantly as NTC restrictions become more severe. This indicates that trading capacities directly influence Switzerland's dispatch behavior. However, it is particularly noticeable that imports from France experience a much sharper decline compared to exports to other countries.

In the Heavy NTC Limitation subscenario, imports from France drop to just 8% of their base case capacity, whereas exports to other neighboring countries are reduced to approximately 23% of their base case levels.

TABLE II. TOTAL ELECTRICITY IMPORT (EXPORT IS NEGATIVE) FROM SWITZERLAND'S NEIGHBORING COUNTRIES FOR THE 2050 MODEL RESULTS.

TWh	Basecase	Medium NTC limitation	Heavy NTC limitation
Import AT	0.3	1.1	0.9
Import DE	-11.4	-2.2	1.2
Import FR	39.5	19.7	8.1
Import IT	-21.7	-10.9	-0.8
Total	6.6	7.7	9.4

As shown in Table II, the situation in 2050 differs significantly from that in 2035. In the Base Case, Switzerland engages in both high imports and exports, but as NTC limitations increase, exports decrease much more than imports.

For example, in the Heavy NTC Limitation subscenario, imports from France are reduced to 21% of their base case level, while exports to Italy shrink dramatically to just 4%.

Figure 3 displays the accumulated storage level of Switzerland's large reservoirs. The model operates with a hydrological year starting in early October and enforces a constraint requiring the storage level at year-end to match its initial level.

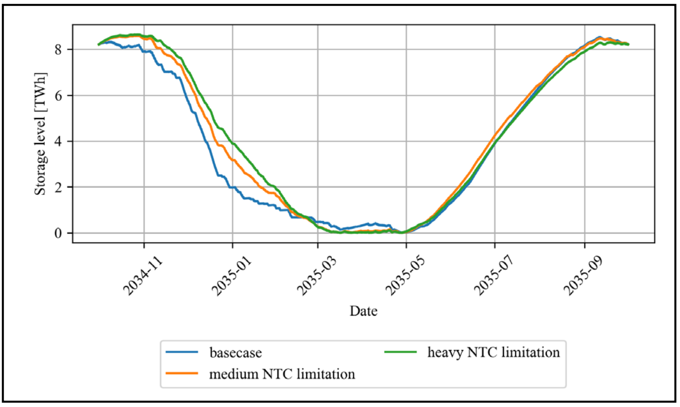

Figure 3. Storage level of the large reservoirs combined in Switzerland in the 2035 simulations.

With increasing NTC limitations, the model adopts a more conservative storage strategy. In the Base Case, the storage level drops to 2 TWh by New Year's Eve, whereas in the Heavy NTC Limitation scenario, it remains at 4 TWh at the same time.

As Figure 4 shows, the situation in 2050 is even more severe than in 2035. By New Year's, in the Base Case, the storage level drops to less than 1 TWh, while in the Heavy NTC Limitation subscenario, it remains at 4 TWh.

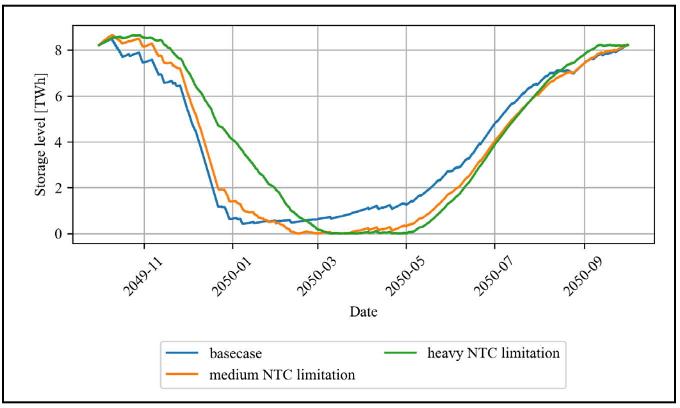

Figure 4. Storage level of the large reservoirs combined in Switzerland in the 2050 simulations.

In the model, lost load is very expensive which is a strong incentive to avoid it. This leads to a possible explanation of the model's varying behavior regarding the storage level in the basecase and the heavy NTC limitation case. If the trade is unrestricted, the model can deplete the storage more aggressively during high price hours and buy more electricity when the price is low in the neighboring countries. With a significant restriction of the NTC however, the model can only buy a limited amount from the neighboring countries leading the model to requiring its own storage in addition to the imports to satisfy its own demand.

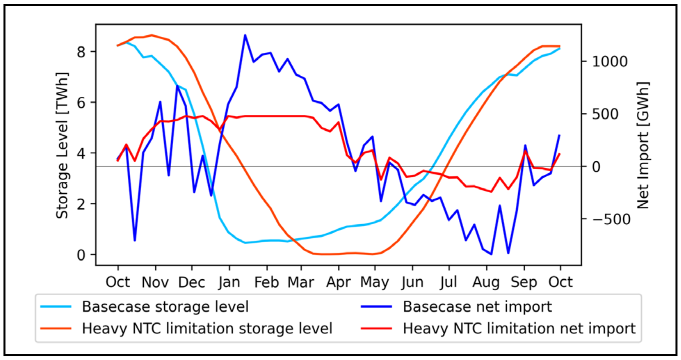

Figure 5. Comparison of Switzerland's large reservoir storage levels and the net imports for the 2050 simulations aggregeted by weeks.

Figure 5 displays the storage levels, and the net electricity import of the basecase, and the heavy NTC limitation case aggregated by the weeks. In the basecase, the model depletes the storage quickly while even exporting electricity. When the storage is empty in January and February, the model makes up for the missing electricity from the storage by importing more.

In the 2050 case with restricted NTCs however, the model does not have the option to import such large quantities in January and February. Thus, it keeps the storage level higher in November and December to have enough left for later.

V. CONCLUSION

This paper presents a two-level stochastic optimization model designed to support investment decisions for Swiss energy policy. In its final version, the model will determine the economically optimal investments in renewable and conventional power plants, as well as storage technologies. It also optimizes the operation of both newly invested and existing plants.

The model runs for the years 2035 and 2050, incorporating large-scale demand-side management (DSM) options such as flexible EV charging and heat pumps. Future versions will also include the flexibility potential of district heating systems.

Given Switzerland's dependence on electricity trade with EU countries, the model integrates stochastic "shock scenarios" that simulate trade restrictions. This allows the optimization to balance benefits from normal market conditions while ensuring resilience under adverse scenarios.

Currently, the model primarily analyzes Swiss electricity trade and large reservoir storage deployment. Findings indicate that with increasing NTC limitations, the model adopts a more conservative storage strategy, depleting reservoirs more slowly to ensure domestic supply. In the base case, the model leverages high-price export opportunities and relies on later imports to meet demand. However, under trade restrictions, it must retain stored energy for self-sufficiency. It is important to note that the model assumes perfect foresight, whereas in reality, storage depletion would be constrained by uncertainty about future conditions.

The impact of NTC reductions differs between 2035 and 2050. In 2035, import reductions are more pronounced than export reductions, suggesting Switzerland can more easily meet its own demand. By 2050, however, exports are more severely restricted than imports, indicating that the model prioritizes securing domestic electricity supply over economic optimization of storage utilization.

ACKNOWLEDGMENT

The authors wish to acknowledge funding for the work on this paper by the Swiss Federal Office of Energy's "Energy-Economics-Society" programme as part of the STORSUPPORT project (grant number SI/502888).

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