SECURITY OF SUPPLY IN THE SWISS ELECTRICITY MARKET: A SYSTEM DYNAMICS APPROACH

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Abstract

Guaranteeing the security of supply (SoS) has become more complex since the liberalization of electricity markets started in the 90's. Liberalization and the ever larger share of intermittent sources (photovoltaic [PV] and wind energy), combined with increasingly interconnected markets, have a direct impact on SoS. Given the large number of elements and stakeholders involved, actions to enhance security may conflict with economic efficiency and/or environmental protection, thus increasing problem complexity.

We develop a SD model that allows us to analyse the investment decision process and, understand, how the presence of PV and wind energy affects the reliability of the system. We focus on the Swiss electricity market, which is currently undergoing a liberalization process, and has simultaneously decided to encourage the implementation of renewable energies and to phase out nuclear energy.

Results of the simulation show that nuclear production is replaced mainly by PV, CCGT and imports, which impacts the SoS negatively. Although installed capacity increases, the decreasing de-rated margin indicates a drop of the system's reliability. This reveals a problem of capacity adequacy that is partially "solved" by increasing imports. Regardless of the increasing share of inexpensive sources, this large dependency drives prices up, especially in winter, and to a lower extend in autumn.

Keywords: electricity markets, system dynamics, intermittent energies, security of supply

1. INTRODUCTION

The decision to pull out of nuclear energy, combined with the increased attention to environmental issues, causes many European countries to face the challenge of providing increasing amounts of "green electricity", in the right place, at the right time. Failing to do so would result in at best rationing, and at worst blackouts. In particular, ensuring the electricity supply is important for governments since the (financial and political) cost of blackouts is high.

Besides the environmental challenges, guaranteeing the electricity supply is even more complex since the liberalization processes started in the 90s. The liberalization of electricity markets creates a dilemma: investment decisions are increasingly based on profitability without explicit view of the systems' security. Moreover, liberalization brings uncertainty to the market, which complexifies the decision making of investors.

A question thus arises: who is responsible for the security of supply (SoS) in an electricity market? Under the old monopoly systems in Europe, it was clear that the responsibility lie with the monopoly company. In these earlier days, there was centralized planning for both primary fuel acquisition (for electricity) and capacity adequacy. Currently, under liberalization, responsibility lies with the market. Furthermore, the introduction of competition adds complexity to the problem of capacity expansion as coordination among investments across the entire supply chain is necessary to guarantee the supply of electricity (Lieb-Dóczy, Börner, and MacKerron 2003). Both liberalization and the larger share of renewable intermittent sources (photovoltaics [PV] and wind energy) have a direct impact on the SoS in electricity markets. The problem is enhanced by the increasing interconnection among countries, e.g. Nordpool and EPEX in Europe.

SoS cannot be defined as one number, whether in terms of reserve margin or capacity adequacy. Ensuring the supply has become a multidimensional problem and there is often a trade-off among the many factors that affect SoS. Given the large number of elements and stakeholders involved (regulator, producers, consumers, network operator, among others), actions to enhance security often conflict with either economic efficiency or environmental protection or both, adding complexity to the problem. Thus, understanding the dynamics of current electricity markets is extremely important when formulating policies.

Our aim is to improve the understanding of the interaction between the elements that affect SoS in the long-term and of how SoS is affected by policies aimed at encouraging investments in green technologies. We develop a simulation model that allows us to analyse both the investment decision process and how the reliability of the system is affected by the installation of large amounts of PV and wind energy. The model is developed using system dynamics (SD). This methodology provides a series of advantages including (*i*) a visualization of the interactions between the different variables and their causal relationship (*ii*) clarifying the impact of the delays on the system's evolution and (*iii*) allowing us to test SoS under different scenarios of energy policy.

Our analysis focuses on the Swiss electricity market, which is currently facing a liberalization process. The Swiss market is characterised by a largely hydro-based system, leading to seasonal production, and long-term contracts (which are steadily expiring) for importing cheap off-peak energy from France (currently about 17 TWh per year, i.e. 25% of national production). Since the Federal Council has decided to decommission the nuclear plants between 2019 and 2034, the SoS is threatened in the middle and long-term.

The paper is organised as follows. The next section provides a literature review and the third section gives a brief overview of the Swiss electricity market. Section four motivates the selected methodology (SD) and presents the model. In the last two sections, results and conclusions are presented.

2. LITERATURE REVIEW

Energy security has become a national concern since events such as the oil crisis in the 70s have proved to have dramatic consequences. Previous work mainly analyses energy security as the challenge of ensuring the supply of fuels (Blum and Legey 2012; Jansen and Seebregts 2010). For instance, Blum and Legey (2012) develop a framework to support the evaluation, planning and implementation of energy security in an economy around resilience, adaptability and transformability of systems. However, they seem to be very concerned about the combustibles' future and their discussion falls short of elaborating a concept of energy security.

Energy security should be understood as a long term issue and a problem that goes beyond securing fuel supply. It is important to understand its multidimensional nature (Vivoda 2010). Although some studies have tried to explore these multiple dimensions, this work remains vague and inconclusive. Yergin (2006) argues that the traditional understanding of energy security (seen as the global concept, of which SoS is a subpart) is too limited and must be expanded to include many new factors and challenges. He also recognises that energy security is affected by international relations.

On the one hand, SoS expresses the system's ability to ensure affordable continuous supply of electricity at a stable frequency and voltage: the latter two elements capture the quality aspect of the good 'electricity' (Jacobsen and Jensen 2012). On the other hand, Helm (2002) defines SoS as the desire for relatively stable prices over time, since the supply is almost always assured. However, the quality of electricity and the stability of prices should be analysed together. Lieb-Dóczy, Börner, and MacKerron (2003) state that SoS is fundamentally about risk: the risk induced by high price volatility and the risk of interruption.

Modelling electricity markets has attracted the attention of the academic world, particularly since liberalization started to take place in the 1990s. Deregulation has received major attention; see for instance Bunn and Larsen (1992), Ford (1999) and Ochoa (2007). These models study the new investment dynamics in England and Wales, in the western market of the U.S.A. and in Switzerland, respectively. These dynamics impact directly the capacity adequacy, and in turn the SoS in those markets.

Liberalization processes establish the legal separation of entities that participate in more than one segment of the chain (generation, transmission and distribution). Liberalization also determines the deregulation of markets and encourages competition among generators (market clearance is done by merit order). This has led to price and capacity cycles, which add complexity to the investment decision making process and leave producers in an uncomfortable position (Arango and Larsen 2011).

In order to stabilize generators' income and to incentivize new investments, several countries have implemented capacity mechanisms. Such mechanisms are usually targeted at peak producers, because these struggle to recover their fixed costs, as the price they receive equals their marginal cost. Such mechanisms are essential to ensure the availability of generation capacity at specific times, e.g. during dry seasons in hydro-based systems. Batlle and Rodilla (2010) discuss several capacity mechanisms and where these have been implemented.

Capacity mechanisms have been studied using simulation models. For instance, Hasani and Hosseini (2011) evaluate the impact of several capacity mechanisms, but their focus on an isolated market, consisting of only thermal technologies, limits the validity of their conclusions. A more realistic model is presented by Arango (2007), who compares two regulation approaches for the Colombian market: availability payments and an options market. The latter leads to less volatility, more stable revenues for companies and slightly lower average prices than the former approach.

These two papers focus on one isolated market, an increasingly rare situation. Cepeda and Finon (2011) assess different regulatory approaches for two interconnected markets: with and without capacity payments. They show that a lack of harmonization between the policies of the two countries leads to market distortions, which in turn result in capacity leakage and free-riding. Another approach addressing the implications of dependency on imports is developed by Ochoa and van Ackere (2009). Although the authors do not consider capacity payments, they find that a high degree of dependency may discourage new investments in the long-term, which in turn has a negative effect on SoS. Dependency on imports also affects prices.

One common characteristic of these models is the limitation to hydro-based, thermal and nuclear generation. None of the models we are aware of consider non-hydro renewables. For instance, Cepeda and Finon (2011) only consider thermal-based and nuclear technologies for the replacement of decommissioned plants. There is a need to include green technologies, and study the impact of their variable output and lower availability (around 23% for wind energy and 13% for photovoltaic against 90% for nuclear energy in Switzerland [Kannan and Turton 2012]). The importance of including wind and PV is highlighted by recent events in Germany: the strong penetration of these technologies in the German electricity mix has led to negative prices in June 2013, and the average monthly wholesale price has decreased from 60 €/MWh in March 2011 to 35 €/MWh in August 2013 (The Economist 2013).

The effect of renewable intermittent energies on electricity systems is not limited to significant price reductions. As assessed by Lise et al. (2013), the main impact will be a need for increased flexibility of the power system. Larger shares of PV and wind lead to higher differences between peak and off-peak residual demand (demand minus intermittent power generation). Therefore, balancing the intermittent generation locally will be more challenging; flexible technologies will be needed: to meet the difference between peak and off-peak demand and to compensate the variability of intermittent technologies. An extreme example is the use of pumped-storage to absorb excess supply when intermittent production is high and to generate when there is lower availability of solar and wind energies. System costs are thus expected to increase due to this increased need for backup and flexible generation.

Furthermore, energy policies increasingly include the use of feed-in tariffs (FiTs) in energy policies in order to encourage investment in renewable energies. Given that FiTs exceed wholesale prices to compensate for the higher capital costs of renewable energies, system costs, and in turn tariffs, are expected to increase even more.

To summarize, SoS in electricity markets has been modelled mainly as a capacity adequacy problem (Cepeda and Finon 2011; Ochoa and van Ackere 2009; Arango 2007; Hasani and Hosseini 2011). However, as mentioned before, ensuring supply is a complex task due to the many aspects that should be taken into account, e.g. reliability, adequacy, environmental impact, affordability, among others. In addition, these models do not address the impact of non-hydro green energies on SoS. A brief description of the Swiss electricity market is presented below.

3. THE SWISS ELECTRICITY MARKET

As shown in Table 1, nuclear energy accounted for 36% of electricity generation and hydro-power accounted for 58% in 2012, compared to 41% and 53% in 2011, respectively: the hydro-power share increased because of higher water reservoir levels, which lowered the production from nuclear plants. Run-of-river power plants account for 26% of electricity production and hydro storage for about 32%. The annual hydro production is 36 TWh and about 60% of which is generated in summer. The share of other sources is 6%, of which non-hydro renewable alternatives accounted for 2.5% in 2011 (data of 2012 not available yet). Switzerland was self-sufficient in meeting its annual electricity demand in 2012, achieving net exports equivalent to 3% of net production.

Table 1. Main statistics of the Swiss electricity market in 2011 and 2012 (SFOE 2013a).

	Volume (GWh)		Share	
	2011	**2012**	**2011**	**2012**
Total production	62,881	68,019	100%	100%
Run-of-the-river	*14,733*	*17,832*	*23%*	*26%*
Storage hydro	*19,062*	*22,074*	*30%*	*32%*
Nuclear	*25,560*	*24,345*	*41%*	*36%*
Others	*3,526*	*3,768*	*6%*	*6%*
Production net of accumulated pumping	60,415	65,608		
National consumption	63,002	63,408		
Net exports	-2,587	2,200		

After the accident in Fukushima (Japan) in March 2011, the Swiss Federal Council announced the phase-out of nuclear energy. The five nuclear plants will be decommissioned as follows: Beznau I (365 MW) and Mühleberg (373 MW) in 2019; Beznau II (365 MW) in 2022; Gösgen (985 MW) in 2029; and Leibstadt (1190 MW) in 2034 (The Swiss Federal Council 2011; IFSN 2013; SFOE 2013a). In order to fill this gap, the country seeks to develop other sources, in particular non-hydro renewable energies.

Following the example of Germany, whose policy has allowed a fast increase of the solar and wind energy shares (Mabee, Mannion, and Carpenter 2012), the Energy Act (OEne) issued in 2009 encourages investments in green technologies. It establishes a system of compensatory feed-in remuneration (CFR) for the following technologies: small hydropower (capacity up to 10 MW), PV, wind energy, geothermal energy, biomass and biological waste (SFOE 2013). For instance, the CFR for PV lasts 25 years, and decreases by 8% per year. It is noticeable that PV capacity has been multiplied by 5.5 between 2009 and 2012 from 79 MW to 436 MW (SFOE 2013b).

Hydro storage could contribute to balance the variable output of wind and solar facilities. However, pumped-hydro is only profitable if plants can compensate their efficiency losses of 15-25% with price differences. The Government and the Energy Federal Office favour combined cycle gas turbine (CCGT) to fill the gap created by the nuclear phase-out. These plants could be used as base load or to balance the fluctuations of renewable energies, but their high emissions are a challenge to their profitability (carbon costs) and acceptance. However, the country is currently softening its regulation regarding the environmental effects from thermal generation. The CO_2 Act establishes that emissions should be entirely compensated, but the most recent modification (2013) allows companies to compensate up to 50% of emissions with foreign certificates.

While production and capacity adequacy receive most of the attention, appropriate grid performance is also essential to insure supply. The Swiss grid needs to be modernized and expanded since consumption and power load are rising, production is increasingly decentralized and fluctuating and, in the context of liberalization, trade is expected to grow. The grid was planned and implemented from the perspective of regional companies and many facilities are now 40 to 50 years old. Only 150 km of lines, i.e. around 4 % of the entire grid, was built in the last 10 years (Swissgrid 2011). Furthermore, there is lack of connections between east and west, leading to congestion of the grid.

The transmission grid not only connects generators to customers, it also connects the Swiss system to its neighbouring countries, which increases the SoS. As shown in Table 2, Switzerland imported a total of 87 TWh and exported 89 TWh in 2012 (including transit electricity). Although net exports amounted to 2,200 GWh in 2012, net imports between November 2011 and April 2012 reached 4,140 GWh, showing a strong dependency on imports in winter. The seasonality of exchanges is shown in Figure 1.

Being an electricity hub is a huge business for Switzerland: in 2012 exports exceeded imports and generated a profit of CHF 771 millions (SFOE 2013a). Note that in 2011, imports exceeded exports by 2,587 GWh, but the net revenue was even higher (CHF 1,018 millions). This is due to the higher difference between exports and imports price. Therefore, integration is not only important for SoS but also for the profitability of the Swiss generators.

Table 2. Electricity exchange in 2011 and 2012 (SFOE 2013a).

	2011	**2012**
Imports (GWh)	83,298	86,825
Average imports price (CHF/MWh)	56.2	60.6
Value of imports (Millions CHF)	4,671	5,257
Exports (GWh)	80,711	89,025
Average exports price (CHF/MWh)	70.7	67.8
Value of exports (Millions CHF)	5,689	6,028
Net exports (GWh)	*-2,587*	*2,200*
Net value (Millions CHF)	*1,018*	*771*

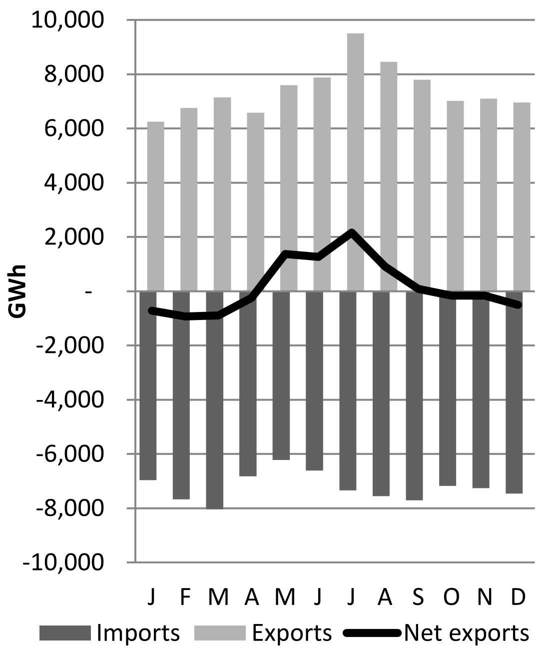

Figure 1. Monthly electricity exchange in 2012 (SFOE 2013a).

The following numbers illustrate the magnitude of electricity exchanges from and to Switzerland: around 23% of Europe's cross border electricity flows transit through Switzerland, while Swiss consumption only accounts for 2% of European energy consumption (Swissgrid 2013). For instance, in 2012 electricity transiting through Switzerland exceeded consumption (63.4 TWh). However, Switzerland will not be able to keep its key role as the electricity hub of Europe in the middle and long-term if generation and transmission capacities become inadequate.

One of the main hurdles to ensuring capacity adequacy in Switzerland is the population's frequent opposition to projects. For instance, the procedure to install new power lines is complex and can take 9 to 12 years. This delay mainly results from public opposition and the large number of authorities involved (Swissgrid 2011). Likewise, hydro-power and wind energy might not develop their entire potential if social pressure keeps narrowing the number of available zones for developing such projects (SFOE 2012). In the case of PV, the general acceptance is higher. In particular, installations on buildings have a better approval rate than stand-alone facilities (AES 2012). These social barriers to capacity expansions endanger the SoS.

A 2008 study by the Swiss Federal Office of Energy (SFOE), estimates the costs resulting from a blackout in Switzerland at between CHF 8 and 30 million per minute. For a day-long power outage, the estimate is between CHF 12 and 42 billion, which is 2 to 7 times the budgeted grid investment over the next 20 years. And this cost does not even include the damage to Switzerland's reputation as a business location (Swissgrid 2011).

4. A SYSTEM DYNAMICS MODEL FOR THE SWISS ELECTRICITY MARKET

As mentioned before, electricity markets are complex as they involve a large number of factors and actors that interact, creating feedbacks in the presence of delays. The liberalisation process has increased this complexity. Gary and Larsen (2000) argue that traditional economic equilibrium models do not adequately address the issues faced by recently liberalized industries: during their transition to competitive markets they do not comply with the equilibrium assumptions. We therefore model the system's structure explicitly. This kind of modelling allows gaining understanding of the dynamics of the industry, which is particularly important for managers during such periods. We use SD to formulate our model.

Methodology

SD models take a system's view of strategic problems and focus on capturing the feedback mechanisms (created by a series of causal relationships) and time delays that define the structure of a given business situation as understood by the key decision makers (Sterman 2000). The system is represented by a set of differential equations. SD has proven to be useful for explaining feedback mechanisms in electric systems (Ford 1999; Bunn and Larsen 1992). Modelling causality and delays is important in energy policy formulation since this helps investigating whether policies trigger instabilities which may affect future system performance (Arango 2007).

This methodology also allows incorporating bounded rationality and stakeholders' behaviour which is more suitable than traditional economic equilibrium models for evaluating markets undergoing a liberalization process. SD has been proved to be suitable for capturing the dynamics of markets at an early stage of liberalisation. Given that there is no historical data for a competitive Swiss market, the use of SD models appears to offer an attractive way of gaining insights into how the market might evolve. For instance, they can generate insights into the effect of price shocks or parameter uncertainties as well as illustrate potential undesirable consequences of the proposed regulation (Larsen and Bunn 1999).

Model formulation

Our objective is to explain the main elements that affect the SoS in electricity markets over the long-term, using the Swiss electricity market as case study. In the following causal diagrams we explain loop by loop the relations among the main variables, whose interactions determine the dynamics of electricity markets. Understanding this will allow us to explain the electricity exchange and the investment decision making process, as well as the threat posed by intermittent renewable energies to investments, which in turn threatens the SoS.

Figure 2 explains how the market is cleared. Total demand results from the local demand and the net flow of electricity exchange. Loops B1 and B2 explain the balance of exchanges (imports and exports). If total demand grows, the gap between supply and total demand (*Gap S-D*) will fall. Since the merit order dispatch depends on marginal costs, a tighter *Gap S-D* leads to higher prices. The market price is compared with the price abroad. If it is higher, then the country will import, but if it is lower, the country will export. Imports satisfy part of the local demand, decreasing total demand (B1), while exports act as additional demand (B2).

Both imports and exports are constrained by cross border capacity, which is not shown in Figure 2, but is included in the model. We consider two types of imports: long-term imports (LTI) based on existing contracts and balancing imports (BI). Long-term imports are assumed to decrease progressively to 0 TWh by 2040, when these contracts will expire. Balancing imports are traded in the spot market.

The reserve margin is a measure of the system's security. If the *Gap S-D* is large, there could be a false sense of security because it includes imports. Thus the reserve margin gives a more accurate view of the SoS since it only compares reliable sources (local capacity and LTI) to local demand.

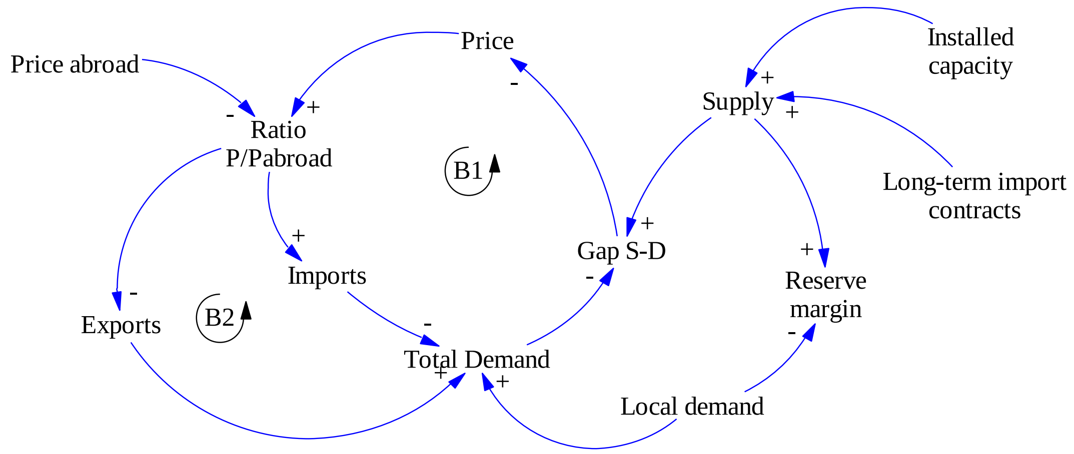

Figure 2. Electricity exchange and market clearance.

The supply depends on the available generation capacity. Figure 3 shows the capacity adjustment process; loops B3 and B4 describe the investment dynamics. This logic is based on the theory of investor behaviour proposed by Ford (2002). Investors estimate the future market price (market assessment), taking into account the expected reserve margin. This margin depends on the expected supply, which in turn depends on both the installed capacity and the projects under construction, i.e. the future installed capacity. As electricity prices reflect the scarcity of supply, a higher reserve margin leads to lower prices and, in turn, to lower profits. The investors' profit assessment depends also on their cost assessment. Given the expected electricity price and the cost assessment (LCOE[1]), they decide whether or not to invest in additional capacity.

[1] The levelized costs of electricity (LCOE) consider capital and operational costs and are expressed in money/electricity generation, i.e. CHF/kWh. The operational costs are easily assessed in these units. When

With time, demand will grow, the expected reserve margin will fall, and expected market prices will rise. When expected market prices reach the investors' target for a new plant, they will start construction. Figure 3 suggests that investors continuously update their assessment of supply and demand as conditions change over time. If they do start construction, their own construction will shape their assessment of the future. This is an aggregate approach that does not differentiate among different companies or among different types of investors.

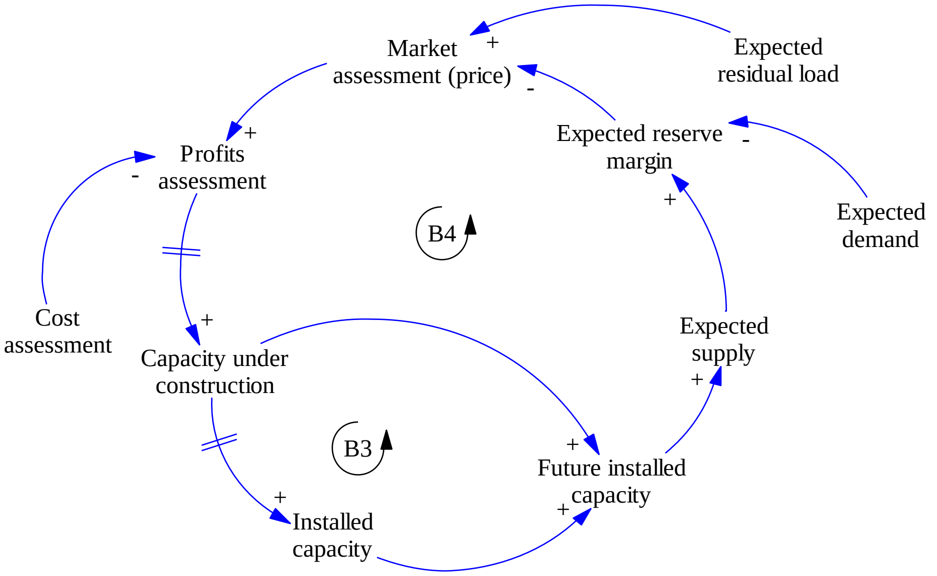

Figure 3. Investors' behaviour (based on Ford [2002b])

Next we turn to the threat posed by PV and wind energy, i.e. the renewable intermittent energies (*Ren-Int*) to SoS. Firstly, more *Ren-Int* capacity will discourage further investments, including those in new intermittent capacity (loops B5 and B6 in Figure 4). Secondly, intermittent supply impacts new investments in CCGT and storage hydro, which is described by the reinforcing loops R7 and R8 (see Figure 5).

As shown in Figure 4, the future intermittent output (determined by installed capacity and capacity under construction) has an impact on prices. The main impact on wholesale prices occurs through the merit order effect. Wind and solar generation have low variable costs. This effectively shifts the supply curve to the right. The same demand can now be met by generation with lower variable cost, resulting in a lower clearing price. A reduction in price assessment will affect the profitability assessment of all producers, discouraging investments in new capacity (B5), and leading to less installed capacity (B6).

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assessing the capital cost per unit generated for a future plant, it is necessary to calculate the Full Load Equivalent Operating Hours (FLEOH) of the plant. As the plant incurs costs throughout its lifespan, it is necessary to take the present value of all the annualized costs.

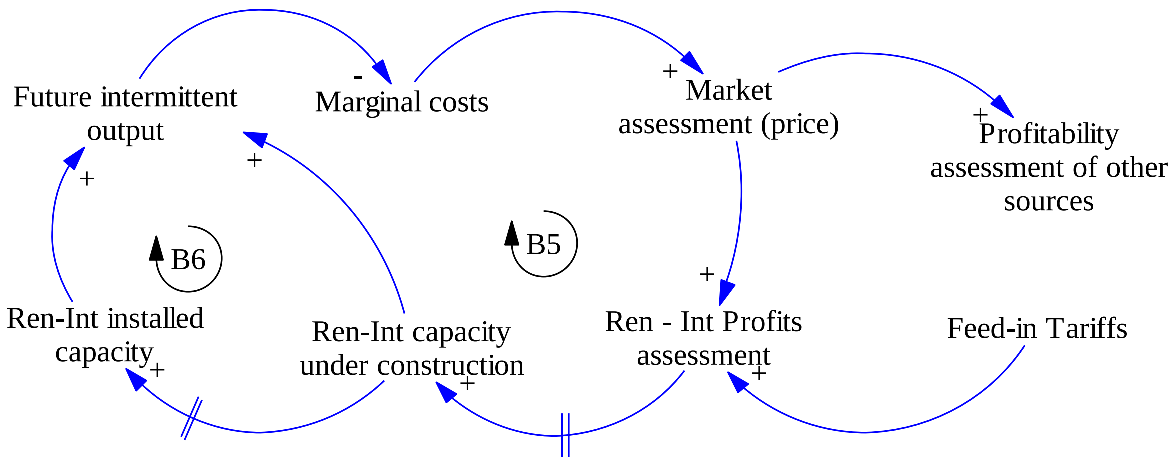

Figure 4. Counterproductive effect of PV and wind energy on investments. Ren-Int : Renewable technologies with intermittent output, i.e. PV and wind energy.

Larger amounts of intermittent generation not only reduce the marginal costs but also the residual demand (the remaining demand after subtracting the load met by intermittent sources), which must be met by other sources. Thus, the generation needed from gas plants and hydro storage (usually used as peak units) will be lower, and so will be their profitability assessment. This discourages investments in those technologies (see Figure 5). Installed capacity of CCGT and hydro storage could indeed decrease if the decommissioning due to obsolescence or low profitability exceeds new investments.

With less peak units in the future, the expected reserve margin will decrease. If the expected reserve margin becomes tighter, higher peak prices will appear. Such prices would be hard to predict given the variability of PV and wind generation. These sudden rises in prices benefit all producers, increasing the attractiveness of investments. However, investors are more likely to select technologies not affected by the reduced generation hours. In other words, even though CCGT and storage hydro could benefit from high prices, these may not compensate the negative impact of shorter operating hours on expected profits. Thus, such sudden price increases may not be enough to encourage investment in peak units, possibly not even in following units. Consequently, intermittent sources will achieve a higher share of net production (R7 and R8). A similar phenomenon occurs when prices are low: because FiTs boost the profitability of renewable energies, there will be comparatively more investments in *Ren-Int* energies.

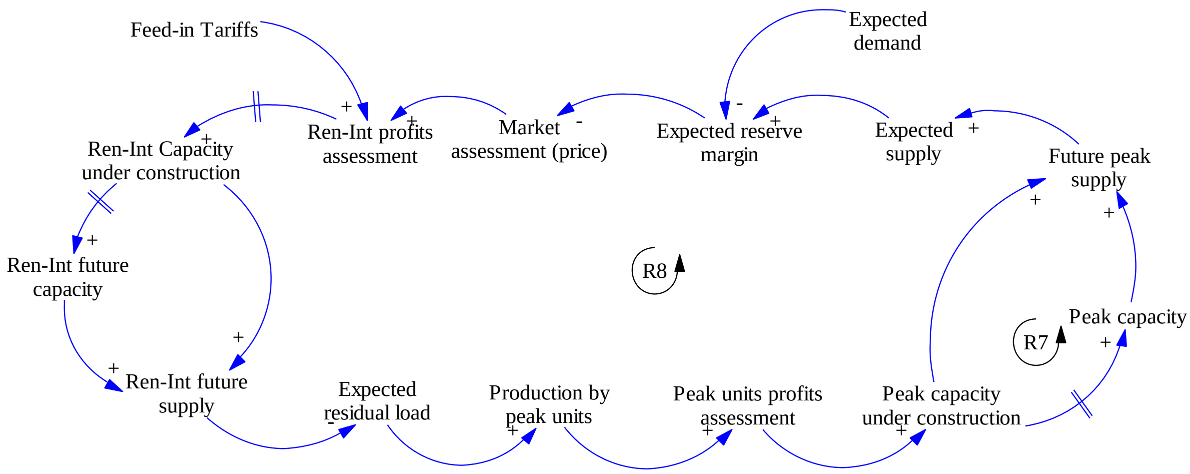

Figure 5. Effect of intermittent technologies on peak units (CCG and storage hydro capacity).

The market assessment made by investors depends on the dynamics between loops B5-B6 and R7-R8, i.e. whether the reinforcing loops or the balancing loops dominate. The expected price variability thus depends on the extent to which the expected residual load could be reduced due to the increasing intermittent output.

Our simulation model uses a quarterly time step to capture the seasonal effects of production and demand. Capturing this seasonality is crucial since it already affects the Swiss market and we expect this effect to gain importance important in the future, as the role of PV and wind energy increases. To fit the Swiss hydrological pattern, seasons are defined as follows: January-March (winter), April-June (spring), July-September (summer) and October-December (autumn). The market is dispatched according to the marginal costs of technologies. The simulation runs from 2013 to 2050 and the key parameters are summarized in Table 3. In addition, the next initial conditions and parameters are assumed:

- To simulate the demand, we use historical data from 2012 to estimate hourly demands for a representative day for each season.
- Demand grows monotonically at 1% per year. Demand could be affected in the long-term by prices. If prices increase, demand could decrease because of fuel substitution. However, this impact is beyond the scope of this paper and we consider demand growth as constant.
- Transmission-border capacity remains fixed at 7,500 MW.
- In 2013 pumping is assumed to equal the average water pumped per season between 1993 and 2012, and afterwards is modified proportionally to the additions of pumping capacity.
- Marginal costs for each technology, except hydro-storage, are exogenous and constant.
- Balancing import prices are exogenous. For each representative day, we built a curve of prices based on 2012 historical data from France and Germany (97% of imports come from these countries).

The model was calibrated using publicly available data, mainly from the Swiss Federal Energy Office (SFOE), the Swiss Federal Council, the Swiss Utilities Association (AES), the International Energy Agency (IAE), the European Power Exchange (EPEX SPOT), the Swiss Transmission System Operator (Swissgrid) and the Italian System Operator (GME). Other sources included the management consulting company Poyry, the Fraunhofer Institute for Solar Energy (ISE), Kannan and Turton (2012) and the association Suisse-eole.

A complete description of the validation process of the model is beyond the scope of this paper. We use the classical SD validation tests (Sterman 2000). Among others, the results of the model are coherent under extreme conditions, as well as when changing different parameters. Furthermore, the model's equations correctly represent the structure presented in the causal diagrams and are dimensionally consistent.

As mentioned before, the Swiss electricity market is largely hydro based. At the end of 2012, hydro-storage, pumped-storage and run-of the-river power plants represent 75% of capacity. Nuclear plants represent 18% of installed capacity while the remaining technologies account for just 7%. This situation is expected to evolve as the potential for expansion estimated by AES (2012) consists mainly of wind energy and PV. The potential for hydro-power development is highly constrained since 90% of water flows in Switzerland are already exploited (SFOE 2012). Additionally, social reluctance keeps narrowing the number of available zones for developing hydro projects. Regarding fossil capacity, most growth expectations lie with the development of new CCGT.

Table 3. Initial conditions of the simulation.

	Initial capacity (MW)	Potential for expansion (MW)	Marginal cost (CHF/MWh)	Average availability factors	De-rating factors
Hydro Storage (HS)	9,920	1,311	11-55*	28%	84%
Run-of-the-River (RR)	3,840	254	11	65%	34%
Nuclear (NUC)	3,278	0	10	89%	89%
CCGT (CCG)	89	3,167	45-67**	92%	92%
Photovoltaic (PV)	422	18,947	2	11%	0%
Wind energy (WI)	49	2,222	1	18%	24%
Conventional thermal (TH)	760	1,333	4-21 **/***	51%	51%
Total	*18,358*	*27,234*			

*Depends on reservoir level.
**We assume step-wise increases for fuel and CO_2 prices over the simulation period.
***Net cost after subtracting the income from heat sales.

De-rating factors are used to calculate the de-rated capacity and in turn the de-rated margin. The former refers to the amount of capacity that is actually reliable at peak-times. The latter refers to the margin between peak demand and de-rated capacity and is used as a measure of system security. Since the demand peak in Switzerland occurs in winter, in the evening, the de-rating factor of PV is 0%. In the case of run-of-the-river and wind energy, the de-rating factor corresponds to the availability factor in winter. The de-rating factor of hydro-storage is significantly higher than the annual availability factor, because reservoirs can be managed to meet peak demand instead of generating in off-peak periods. Therefore, this factor is linked to the flexibility of this technology. Regarding the fuel generators, the de-rating factor equals their availability factor.

Except for the low average availability of conventional thermal, the average availability factors of non-renewable technologies are significantly higher than those of renewable sources. This is particularly important when trying to measure the security of the system since capacity is not always available. The next section presents the main results regarding the evolution of capacity, de-rated margin, energy mix, prices and exchange of the Swiss electricity market.

5. RESULTS

Investments are highly concentrated in non-hydro renewable energies as shown in Figure 6. This is a consequence of their profitability and potential. The total available capacity grows from 18.4 GW in 2013 to 42.7 GW in 2050. The growth is continuous, except in 2028 and 2033, when the last two nuclear plants are decommissioned. The main result is the reconfiguration of the energy mix: the nuclear plants are replaced mainly by PV and wind (Figure 6), and non-renewable energy production decreases from 44% in 2013 to 18% in 2050 (Figure 7).

Storage-hydro significantly increases in 2016 and 2017, when Nante de Drance (900 MW) and Limmern (1,000 MW), respectively, are scheduled to start operating. These two plants are currently under construction. Both storage hydro and run-of-the-river capacity slightly increase after 2017. The CCGT capacity increases more than 40-fold, from 89 MW to 3,271 MW, while the thermal capacity grows non-monotonically from 760 MW to 1,988 MW. Both investments in CCGT and thermal capacity are owed to the need of meeting winter demand in the absence of nuclear energy. In both cases the full potential expansion is used.

The expansion achieved by PV capacity (from 400 MW in 2013 to 18,650 MW in 2050) is the highest among all technologies due to their larger expansion potential. The support of FiTs is crucial for the growth of PV. FiTs occasionally exceed prices by more than 100%, allowing covering the LCOE. PV has the highest LCOE among all technologies considered because of high capital costs and limited availability. Likewise, the growth of wind capacity (from 57 MW to 2,049 MW between 2013 and 2050) occurs because of the support of FiTs. The construction of PV and wind plants is encouraged to partially fill the gap left by the nuclear phase-out.

The changes in capacity mix impact not only the amount of electricity generated but also the energy mix. This is highlighted in Figure 7. The net production (from local sources) in Switzerland drops in the years when nuclear plants are decommissioned. The main drop occurs is in 2030 when Gosgen is decommissioned and net production decreases by 5 TWh. Until then, net production exceeds annual demand, which implies that Switzerland is a net exporter. Afterwards, Switzerland is no longer self-sufficient. To summarise, the production of nuclear plants is partially replaced by PV, wind energy and CCGT production. The remainder of the gap is filled by balancing imports; while available, the remaining long-term import contracts are fully used and cannot be increased (we assume no new contracts are signed). We discuss the country’s imports dependency in more detail at the end of the section.

Hydro-storage and run-of-river production remains fairly steady around 27 TWh and 16 TWh, respectively; their represent about 30% and 26% of net production. The share of hydro production peaks at 63.2% in 2035. However, this increase reflects a decrease in net production rather than an increase in hydro production.

When nuclear energy is totally abandoned (2034), the gap left by the last nuclear plant is mostly filled by CCGT, which increases its production from 1.5 TWh to 4 TWh. This increase is not due to an increase in capacity but to an increase in the load factor. Therefore, although investments in CCGT are encouraged to meet winter demand (as peak units), the nuclear phase-out transforms these plants in following units: their usage increases almost 3 fold. Still, CCGT's utilisation rate remains below that of nuclear plants because of its higher marginal cost. After 2035, total production increases steadily to 77.8 TWh in 2050.

When comparing the evolution of capacity and net production, it is important to note that although PV accounts for 44% of total installed capacity in 2050, its maximum share in production is only 22%. On the contrary, thermal capacity remains below 6% of installed capacity but its share of total production is around 10%. This is directly related to the availability factors discussed before.

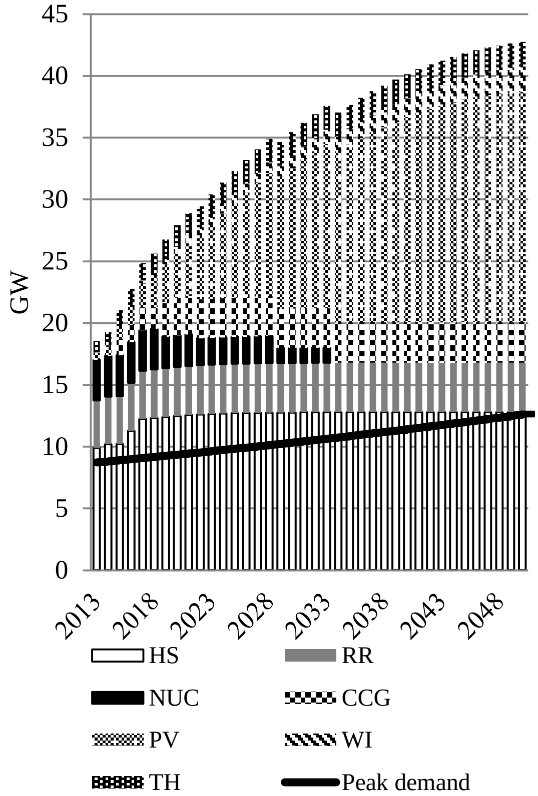

Figure 6. Simulation of installed capacity and peak demand from 2013 to 2050.

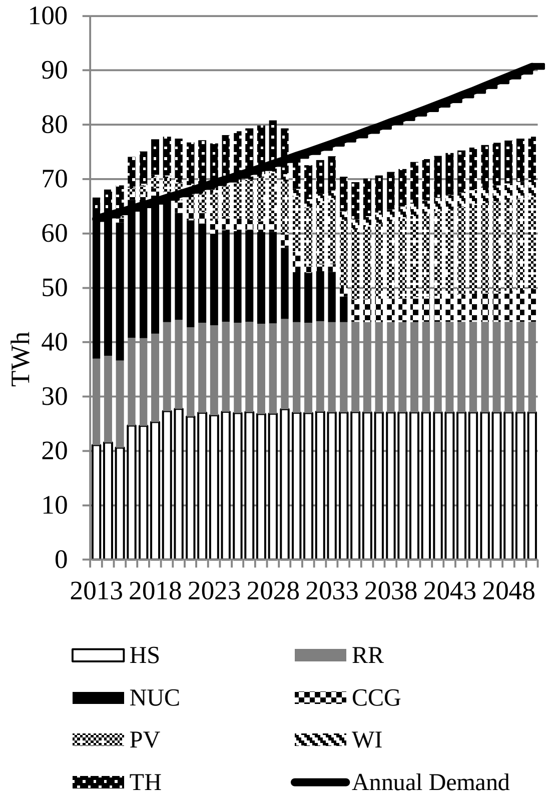

Figure 7. Simulation of energy mix of Swiss net production from 2013 to 2050.

Next we turn to the implications of the changes in energy mix on Switzerland's SoS. Although SoS is not only about capacity adequacy, we initially focus on the capacity margin. Next we will elaborate on the implications of higher prices. The de-rated margin allows measuring the system's capacity to meet peak demand. Traditionally, total available capacity was taken as the sum of the full theoretical capacities of all plants of the system. The capacity margin calculated in this way is now referred to as 'gross capacity margin'. Owing in large part to the increasing role of renewable intermittent resources, whose average availability is below 25%, the de-rated capacity margin is increasingly preferred as capacity margin measure (Royal Academy of Engineering 2013). For instance, this is one of the measures used in the UK to assess the system's reliability (OFGEM 2013).

In the case of Switzerland, total capacity always exceeds twice the peak load (see Figure 6); however, the de-rated margin never exceeds 50% (Figure 8). It is important to recall that the de-rated capacity margin is calculated as spare de-rated capacity divided by total de-rated capacity. Between 2013 and 2021 the de-rated margin increases from 32% to 47% due to the entry of the two large hydro-power plants currently under construction and investments in CCGT. After 2021, the de-rated margin gradually decreases to 25% in 2050 because the de-rated capacity increases less than demand. Therefore, the increase of available capacity might give a false sense of security. Figure 8 also shows that the decrease of the de-rated margin starts when the share of PV and wind farms capacity exceeds 20%. This is due to the replacement of nuclear capacity by sources with a much lower de-rating factor.

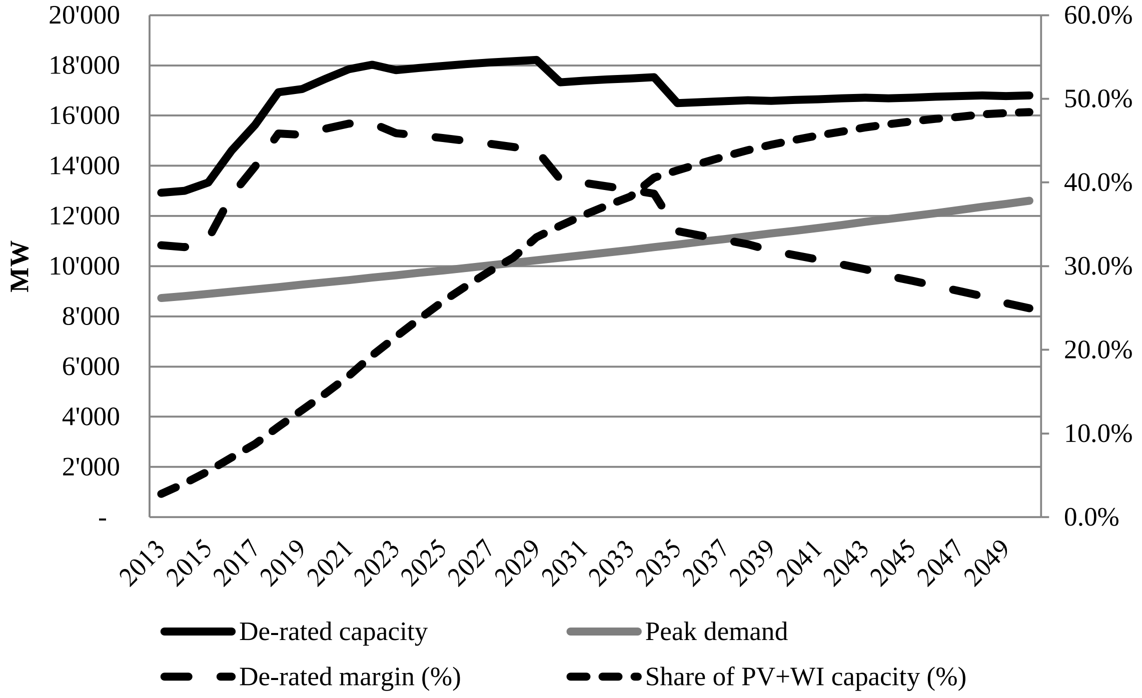

Figure 8. Impact of renewable intermittent technologies on system's reliability.

The security of the system does not only relate to its reliability but also to affordability. Although one might expect prices to decrease due to the larger share of zero-marginal cost sources (PV and wind), we observe the opposite: the average electricity price increases from 32 CHF/MWh to 55 CHF/MWh between 2013 and 2050 (see Figure 9). The annual average price remains around 32 CHF/MWh until the decommissioning of the last two nuclear plants (2028) and increases sharply over the next 7 years. This increase is partly explained by the increase in balancing imports which are more expensive (from 17 TWh to 35 TWh between 2028 and 2035). According to our model, prices are expected to increase in Switzerland because of the change in the electricity mix: nuclear energy is replaced by less expensive technologies such as PV and wind, but also by more expensive sources such as CCGT and balancing imports.

A consistent finding in the literature, e.g. Hirth (2013), is that higher levels of wind capacity can lead to increased levels of price volatility. Sudden variations in generation may require the dispatch of plants with quick start or rapid ramp rate capabilities, which often have high variable operating costs. Such technical features are not included in the model as they are beyond the scope of this paper and would require using a stochastic modelling. Our simulated price could thus underestimate the full impact of a larger share of renewable intermittent sources.

The seasonal effect of the changes in energy mix on quarterly prices is highlighted in Figure 9. Increases in quarterly prices are stronger in autumn and winter, when there is little (noon) or no (evening) solar generation at peak demand. In summer, there is no significant change in quarterly prices because of the reasons mentioned above. Therefore, annual average prices are driven up mainly because peak prices increase significantly in autumn and winter.

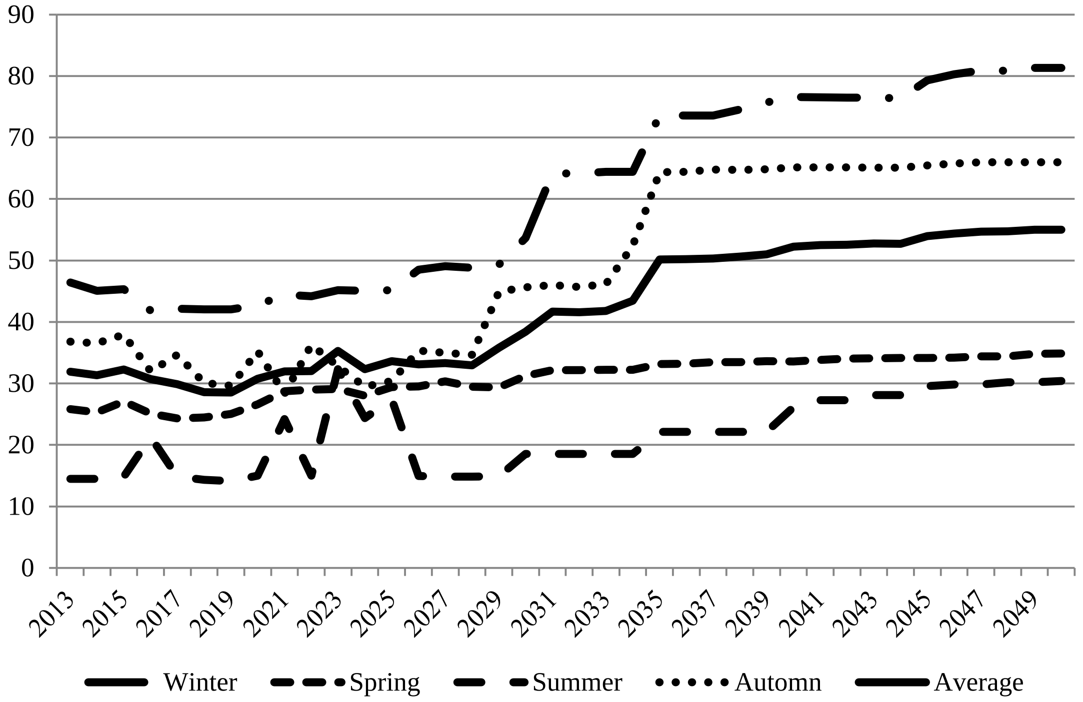

Figure 9. Seasonal and annual average prices (CHF/MWh).

The effect of intermittent sources on prices can also be magnified by the shape of the hourly demand curve. In Switzerland, this impact is limited. In spring and summer, peak demand occurs at noon, while in autumn and winter there are two peaks (the difference between demand at noon and demand at evening is less than 5% - see Figure 10).

Figure 10 illustrates how the change in technology mix affects winter and summer prices differently. In both seasons, the difference between peak and off-peak prices increases in 2050. In particular, in winter the price increase at peak hours is higher in the evening than at noon. The decommissioning of nuclear plants has increased the ratio between peak load and base load, and the country has become dependent on balancing imports to meet both the noon and evening peaks, however, as there is some solar energy at noon, prices are lower than in evening.

Although in summer demand peaks when sun availability is at its highest, output from PV and wind is insufficient to meet this demand even in summer. Thus, other technologies such as hydro-storage and run-of-river are required. Consequently, even though PV capacity represents about half of installed capacity, prices do not drop.

The shape of hourly prices in summer changes significantly between 2015 and 2050. The price in 2015 is flat as the marginal producer is always the same (hydro). But in 2050, peak prices occur at off-peak hours (before 9.00 and after 19.00), when solar output is limited or unavailable. The overall effect of these issues is that the difference between peak and off-peak prices is much larger in winter than in summer.

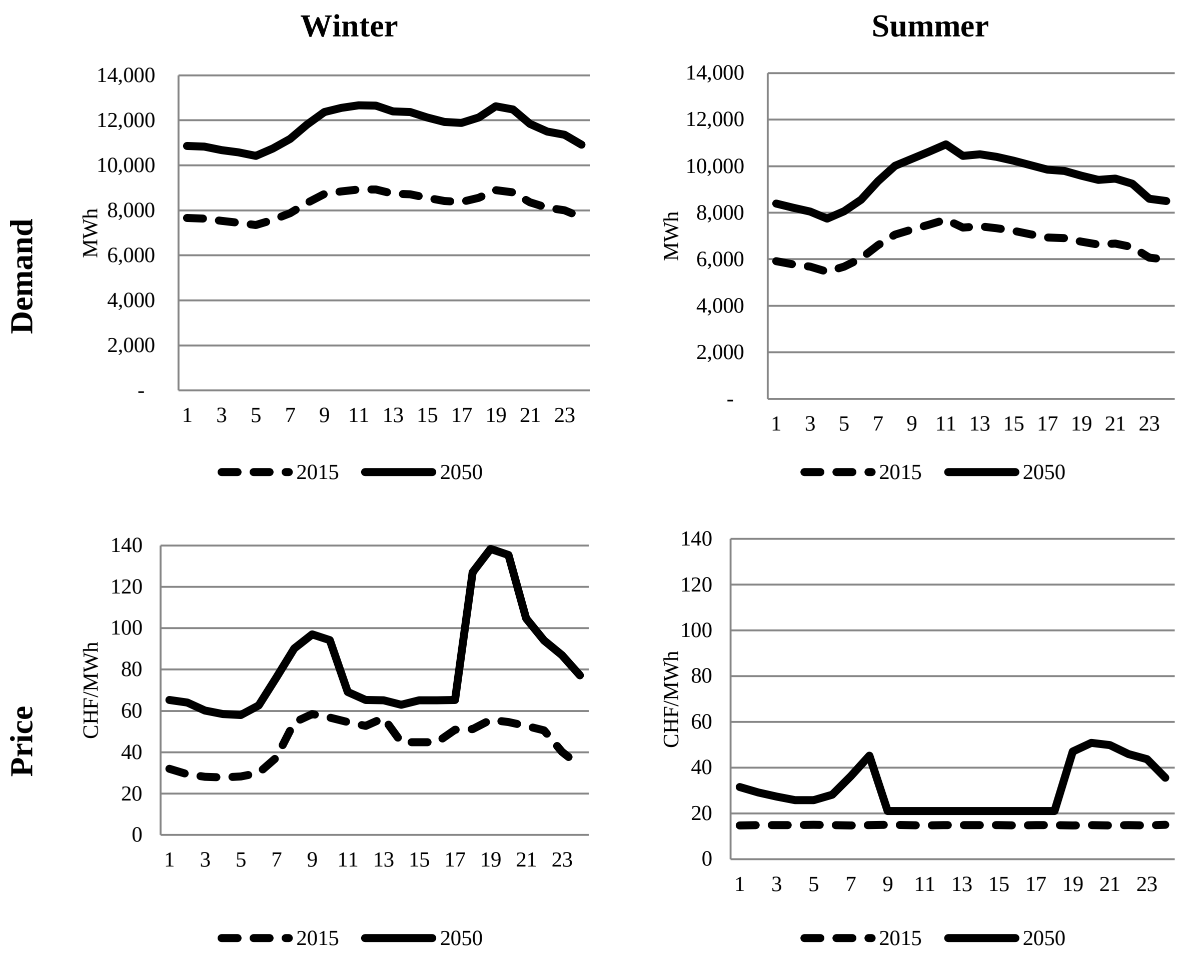

Figure 10. Comparison between hourly demand and prices in winter and summer in 2015 and 2050.

It is important to note that we assume in the model that the energy-mix of neighbouring countries does not change, thus their hourly price curve remains the same over the entire simulation period. A significant change in their prices could have significant consequences on Switzerland's prices and its exchange patterns.

The annual average price rise is also triggered by a reallocation of hydro storage generation. Currently, hydro storage is used in Switzerland mainly to satisfy peak load, and for exports. Given that the availability of cheap electricity (nuclear plants and long-term agreements) decreases, hydro storage is reallocated to meet a higher share of national demand. Hydroelectric power stations are no longer used as peak units, but as load-following units.

This reallocation decreases the reservoir levels, which in turn, increases the reservation price (opportunity cost) of hydro-storage producers. Generation patterns follow inflows more closely and generators thus have less arbitrage opportunities. This situation reveals a problem of capacity adequacy, which in turn leads to a reduction of Switzerland's ability to export.

The problem of adequacy is partially "solved" by relying increasingly on imports, as illustrated in Figure 11. Switzerland thus becomes a net importer from 2031 onwards. Annual imports increase from 33 TWh in 2013 to 42 TWh in 2050 and net imports reach 13 TWh at the end of simulation (14% of national consumption). This is a significant fact since over the 1993-2012 period, the maximum amount of net imports was 6.4 TWh in 2005, and in only 4 years out of 20 did imports exceeded exports. This dependency is exacerbated in winter, when net imports reach 44% of national consumption.

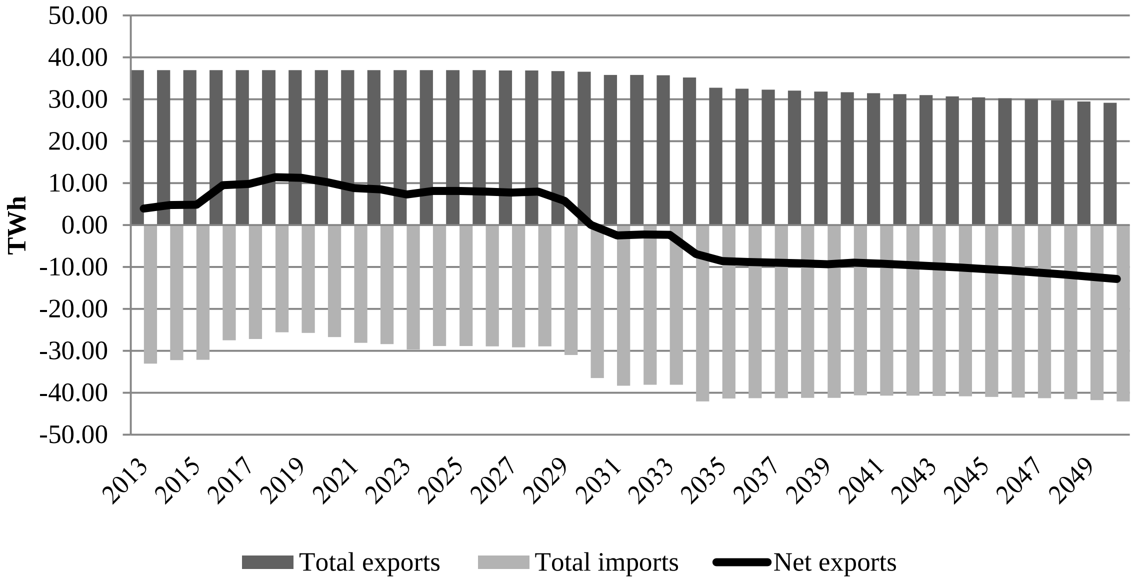

Figure 11. Exchange of electricity (in TWh).

Such a dependency is risky. Imports might be cut by neighbours for political reasons or due to extreme weather conditions, which would bring devastating consequences for Switzerland. For instance, one might imagine that in a week under a polar vortex, the supply in Switzerland would be seriously endangered if France and/or Germany lack excess capacity. Such risks are enhanced if we consider that the gas used by CCGT is imported (mainly from Russia) and CCGT production in winter reaches 16% of winter consumption from 2035 and on. Then, in aggregate terms, dependency would reach 60%. Beside these geopolitical factors, a large dependency might not be politically acceptable for the government in Switzerland.

Table 4 shows that exports decrease from 37 TWh to 29 TWh between 2013 and 2050. In relative terms, the reduction in the exports to France is the most significant (50%), compared to Italy (14%) and to Germany (29%). Demand for exports to France and Italy occur mainly at peak hours, but prices in Italy are significantly higher (average price of 75 €/MWh vs. 47 €/MWh in EPEX-France). In Switzerland, as discussed before, wholesale prices increases more at peak hours than at off-peak hours in winter. This, and the difference in willingness to pay (market prices) of France and Italy, explain the larger drop of exports to France.

Demand for exports to Germany is highest in spring and summer at off-peak hours than in winter and spring. Given that off-peak prices in summer significantly increase compared to prices at peak hours, exports to Germany are also affected (from 3.7 TWh to 2.6 TWh). As the export to Italy is assumed to be the highest, this increases the average price of exports.

Table 4. Electricity exported and price paid by neighbouring countries (France, Germany and Italy).

	Exports (TWh)			**Average export prices (CHF/MWh)**		
	2013	**2035**	**2050**	**2013**	**2035**	**2050**
France	5.87	3.74	2.95	33.01	40.15	40.25
Germany	3.68	2.96	2.60	24.43	28.03	34.16
Italy	27.45	26.05	23.64	31.25	48.40	50.49

Total	*37.00*	*32.74*	*29.19*	*30.86*	*45.62*	*48.00*

The increasing dependency on imports and the decrease of exports have a strong impact on the profitability of the electricity exchanges. As mentioned before, Switzerland is a hub of electricity trade and a huge part of the utilities' business consists of arbitrage by Swiss generators. Despite the export price increase, the value of exports increases moderately because of the significant drop in exports volume. At the same time, the volume and the imports price increase between 2013 and 2050. Thus profits from the exchange are seriously affected as illustrated in Table 5: the country no longer presents a surplus by 2050. In 2020 there is a drop in imports due to the excess of inexpensive capacity in Switzerland after two large storage hydro power stations come on line.

Table 5. Volume, average price and value of electricity exchange in Switzerland.

	2013	**2020**	**2030**	**2040**	**2050**
Volume of imports (TWh)	33.1	26.8	36.5	40.6	42.1
Average imports price (CHF/MWh)	23.3	24.4	27.6	36.6	37.5
Value of imports (Millions CHF)	770	653	1,008	1,488	1,577
Volume of exports (TWh)	37.0	37.0	36.6	31.7	29.2
Average exports price (CHF/MWh)	30.9	29.9	37.2	47.1	48.0
Value of exports (Millions CHF)	1,142	1,105	1,359	1,493	1,401
Net exports (TWh)	*3.9*	*10.2*	*0.1*	*-8.9*	*-12.9*
Surplus (Millions CHF)	*371*	*452*	*351*	*5*	*-176*

While larger amount of imports could be seen as positive if purchases are made at prices below those of national producers, Ochoa and van Ackere (2009) show that dependency has a negative effect on investments in the long-term.

6. CONCLUSION

Our model helps understanding the new challenges that a large(r) capacity and output of renewable intermittent energies poses to regulators, and how this evolution can jeopardise the SoS in electricity markets. Replacing a large share of the retired nuclear capacity by PV and wind farms causes the de-rated capacity to become a smaller fraction of the total installed capacity. Consequently, the SoS of the Swiss market decreases even though total installed capacity increases. Therefore, the increase in installed capacity may give a false sense of security.

Furthermore, the increase of PV and wind energy causes an extra challenge for the system since dependence on meteorological conditions complicates the dispatch of electricity. As both solar and wind outputs are more difficult to forecast than, for instance, water inflows, and weather conditions change unexpectedly, the reliability of the system might be endangered as supply should match demand at every point in time.

Our results indicate that this is not the only threat to the SoS of the Swiss market; the country also becomes highly dependent on electricity imports, especially during winter. Although Switzerland has been occasionally a net importer on a small scale in the past (e.g. 4.1% of national consumption in 2011), results show that in the future the country may need net imports amounting to 14% of annual consumption, and up to 44% of winter demand. This dependency is even higher if we consider the gas imported to produce 16% of national consumption in winter (CCG).

Although Switzerland has close economic and political relationships with its neighbours, such a large dependency makes the country extremely vulnerable to climatic and geopolitical risks. In particular, the referendum approved on February 9th, 2014, has put Switzerland in an uncomfortable position towards the EU, who has unilaterally suspended the negotiations on cross-border energy trade. This, together with the political unpopularity of such dependency, might lead the country to review its energy policy, in particular regarding nuclear energy and the constraints on the expansion potential of hydro-power.

Since the IEA (2013) refers to energy security as the uninterrupted availability of energy sources at an affordable price, we can conclude that the SoS in the Swiss electricity market is seriously threatened by this import dependence, as well as by the significant price increase. In addition, the higher volatility in quarterly prices brings uncertainty to the market, which could lead to undesirable practices by some producers (e.g. utilities deliberately declaring certain units unavailable in order to increase peak prices even further), posing an even higher threat.

Given that the intuitive consequence of a larger share of PV and wind energy is a price drop, the results of our model are at first sight unexpected. The price rise in Switzerland results from the replacement of a cheap source (nuclear energy) partly by more expensive sources (CCG and balancing imports), which are typically used as peak load. Nuclear plants cannot be replaced entirely by solar and wind energy since their potential is not large enough and their availability at peak times in winter and autumn is limited or nonexistent. This affects the supply curve: there will be a larger difference between the less expensive sources (base load) and the most expensive sources (peak load). Note that a price-collapse as observed in Germany (from 60 €/MWh mid-2011 to 37 €/MWh mid-2013) is unlikely in Switzerland, due to peak demand occurring at noon, i.e. when PV production is highest.

On the one hand, high prices negatively affect consumers and the profitability of electricity exchange. On the other hand, they might be an advantage for the Swiss market because they enable investments in expensive -but reliable- technologies (hydro storage and CCG).

These issues illustrate the complex problem that the regulator and energy policy makers face as they deal with several conflicting objectives. They should keep the incentives for green technologies in order to meet the environmental commitments, but without discouraging investments in other technologies. Additionally, they must manage the dependency on imports. To sum up, they should guarantee the SoS in terms of reliability, adequacy and sustainability (affordable prices and environmentally friendly).

Our model has several limitations. First, while our model does predict a tariffs increase, this increase may be underestimated for several reasons. The impact of PV and wind energy is underestimated because dispatch of plants to replace sudden downturns in intermittent generation can lead to higher spot prices as the need to use plants with fast ramp-up intensifies (SKM 2013). Also, transmission costs, which are not included in the model, are expected to rise due to the increased production from intermittent sources.

Annual peak demand is also underestimated since hourly demand is assumed to equal the average of seasonal hourly demands. The de-rated capacity margin is thus underestimated, and so is the SoS in the Swiss market. This indicates that the capacity adequacy problem might be worse, and the impact on the system's reliability and on imports dependency more serious.

We assume that pumping will follow the same pattern as during the 2003-2012 period. However, the increased share of renewable intermittent energies may affect this pattern: water might be pumped at peak hours in summer rather than off-peak hours because of lower prices (recall Figure 10). In further work, pumping decisions will be made endogenously in order to capture the arbitrage opportunities and the dynamics resulting from expected changes in hourly prices.

Another model boundary issue relates to the interaction with neighbouring markets. The electricity exchange and Swiss market prices will depend on the energy-mix changes in neighbouring countries, which we assume constant. For instance, a larger development of PV and wind energy in Germany will lead to further price drops. This might in turn cause additional decreases in Switzerland' exports to Germany. Furthermore, imports might be strongly increased in winter if that country achieves a larger development of wind energy and solves its transmission capacity limitations between north and south.

On the contrary, exports could increase if neighbouring countries also decide to decommission nuclear plants and replace these by more expensive technologies. In further work we will consider different scenarios concerning the energy-mix of neighbouring countries, and how this would affect imports and exports opportunities and prices. Also, other storage technologies such as batteries are expected to improve which will likely decrease the impact of intermittence in the generation. This effect might prove important in the future and will be explored in further work.

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