Strategies for integration of Variable Renewable Generation in the Swiss electricity system

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Keywords

Electricity storage; long-term energy scenarios; electricity grid; dispatchable loads; load curtailment; TIMES energy model

Introduction

Renewably energy is identified as an important contributor to climate change mitigation in the IPCC's 5th Assessment Report [1]. Worldwide there is an increase in energy and climate policies oriented towards promotion of renewable energy sources (RES) such as wind and solar in the electricity sector. However, high variability and volatility of RES are challenging for electricity supply and demand balancing. Thus, increasing penetration of wind and solar in the electricity system raises concerns about long term electricity grid stability and thereby security of supply. The aim of this paper is to assess long term strategies for increasing penetration of stochastic renewable electricity in energy system using insights from Switzerland. A particularity of the Swiss energy system is that the electricity sector is almost "CO_2-free" as power generation is primarily from hydropower (56% on average), nuclear (37% on average), other renewables (4% on average). Over the past two decades there were no major changes in the structure of the Swiss electricity generation, except deployment of some solar PV in recent years. The Swiss energy policy aims to gradually phase out nuclear power and promote energy efficiency and renewable energy as means to maintain sufficient electricity supply. Contributions from solar PV and wind power are expected to be about one-fourth of the total electricity production by 2050 [2]. In view of this long-term objectives of the Swiss energy strategy, we examine the following alternatives for integrating RES in the Swiss electricity system:

- Employing a range of electricity storage options at both the transmission and distribution grid levels, such as pump hydro storage, compressed air energy storage and batteries of different sizes.
- Increasing the penetration of dispatchable loads, such as electrolysers for hydrogen production, water heaters and heat pumps to offer flexibility to shift the electricity demand in time, so that the generation/load can be temporarily balanced.
- Reinforcing and expanding the network as required by the energy flows in the grid.

In our analysis, we apply an energy systems model with high intra-annual resolution and with endogenous representation of stochasticity of wind and solar PV electricity production. We have also introduced electricity grid transmission constraints and ancillary services markets. We apply the model to a set of alternative long-term scenarios to assess the aforementioned RES integration measures under different policy frameworks for the Swiss electricity sector for the horizon 2020-2050

Methodology

The modelling framework used in this study is based on the Integrated MARKAL-EFOM System (TIMES), a model generator developed by the International Energy Agency – Energy Technology Systems Analysis Program (IEA – ETSAP) allowing for specific energy systems to be modelled and analysed [3]. We use the Swiss TIMES energy system model (STEM) [4], which is a bottom-up model covering the Swiss energy system from resource supply to end use over a long-term horizon (2010 – 2100). A distinguished feature of the model is its high intra-annual time resolution, in which each modelling period is divided into 288 typical operating hours. These correspond to four seasons, with three typical days (a working day, a Saturday and a Sunday) with hourly resolution. In the current analysis, the electricity sector of the STEM model has been further enhanced by including additional features:

- Enhanced representation of the electricity sector, in which different grid voltage levels
- A spatial representation of Switzerland to model grid topology in 15 aggregated nodes
- Introduction of electricity storage options other than pump hydro, such as Compressed Air Energy Storage (CAES) and batteries at different sizes, at different grid voltage levels and for different applications (e.g. industrial, commercial, residential).
- Introduction of stochastic variability of electricity from wind and solar PV
- Representation of provision of secondary (and primary) control reserve

The STEM model distinguishes four electricity grid levels from very high to low voltage[1]. Figure 1 gives an overview of the electricity sector structure, which also shows the different power plant types and storage options that can be connected to the individual grid levels. The modelling of electric grid topology is well documented in [5].

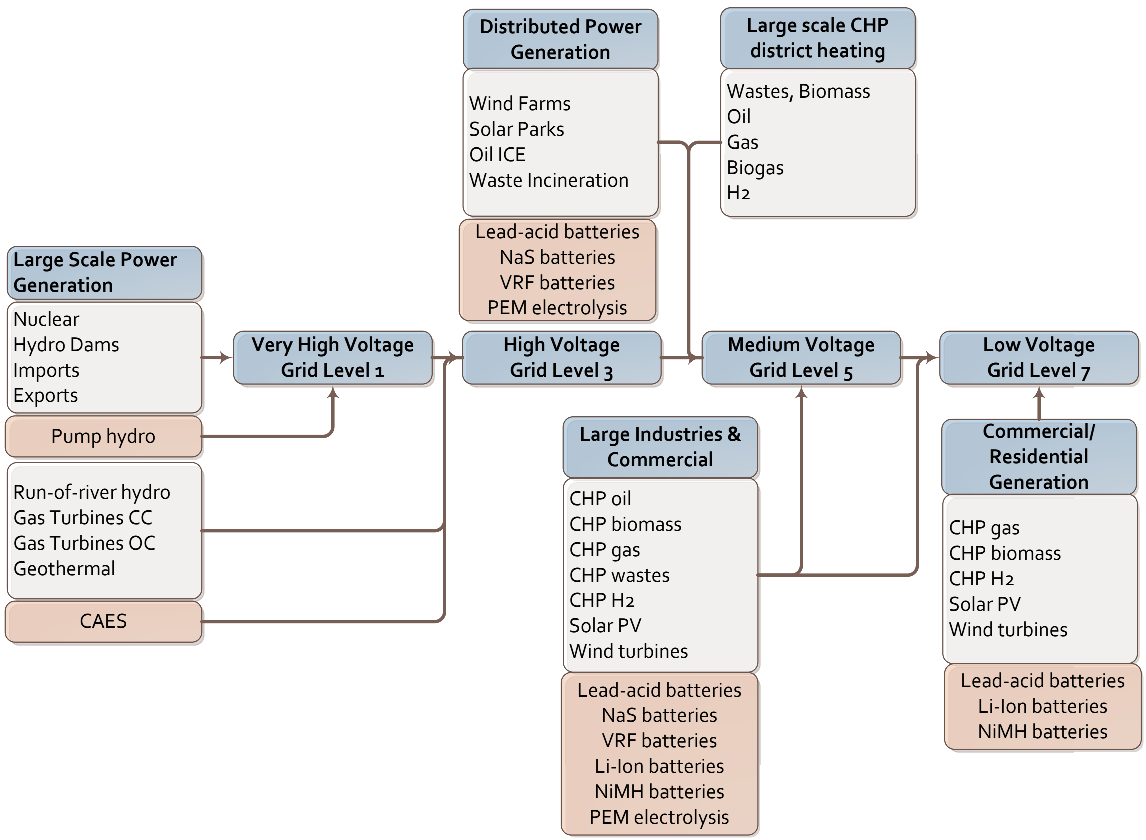


Figure 1: Overview of the electricity sector in the enhanced STEM model.

The electricity storage technologies are differentiated by costs, application/use and temporal storage characteristics: batteries can provide hourly to daily storage cycles while CAES and pumped hydro can provide

[1] Grid level 1 corresponds to 220/380 kV, grid level 3 corresponds to 36-150 kV, grid level 5 corresponds to 1-36 kV and grid level 7 corresponds to 0.4-1 kV. Grid levels 2, 4 and 6 correspond to transformation levels.

weekly, daily and hourly storage. In addition, a range of power-to-X pathways (X=hydrogen, gas, electricity) are integrated in STEM. For example, electricity is converted to hydrogen (PEM electrolysers), which can be:

- directly injected into natural gas grid (max 0.6% in terms of mass)
- utilised on-site (fuel cells)
- converted into methane and used in transport, heating and electricity generation sectors.

These power-to-X pathways are envisaged suitable for seasonal storage in Switzerland. Finally, on the demand side heat pumps and water heaters are capable of shifting electricity loads such that the consumption of electricity occurs at a different hour from the heat production.

The electricity grid topology is based on a transmission network model [6] of Switzerland and its neighbouring countries, which has been aggregated into 15 nodes and 638 electricity grid elements that include lines, transformers and busbar connections (Figure 2). In this aggregated topology, seven Swiss regions are represented as single nodes (in terms of load injection and withdrawal), while additional four nodes are included for each one of the existing Swiss nuclear power plants[2]. In addition, each of the four neighbouring countries is also represented as a single node. The algorithm applied for aggregating the detailed Swiss electricity grid was developed by ETH Zurich/FEN [7]. The output of the algorithm consists of a set of DC power flow equations in the form of $\mathbf{H}\times(\mathbf{g}-\mathbf{l})\leq\mathbf{b}$, where $\mathbf{g}$ is Nx1 vector of electricity injections in each node, $\mathbf{l}$ is Nx1 vector of electricity withdraws in each node, $\mathbf{H}$ is ExN power flow distribution matrix across the grid elements E and nodes N and $\mathbf{b}$ is an Ex1 vector with the thermal capacities of the grid elements. In this context, a violation of a particular constraint in STEM from the set of the E constraints implies a violation of a grid constraint in the detailed Swiss network.

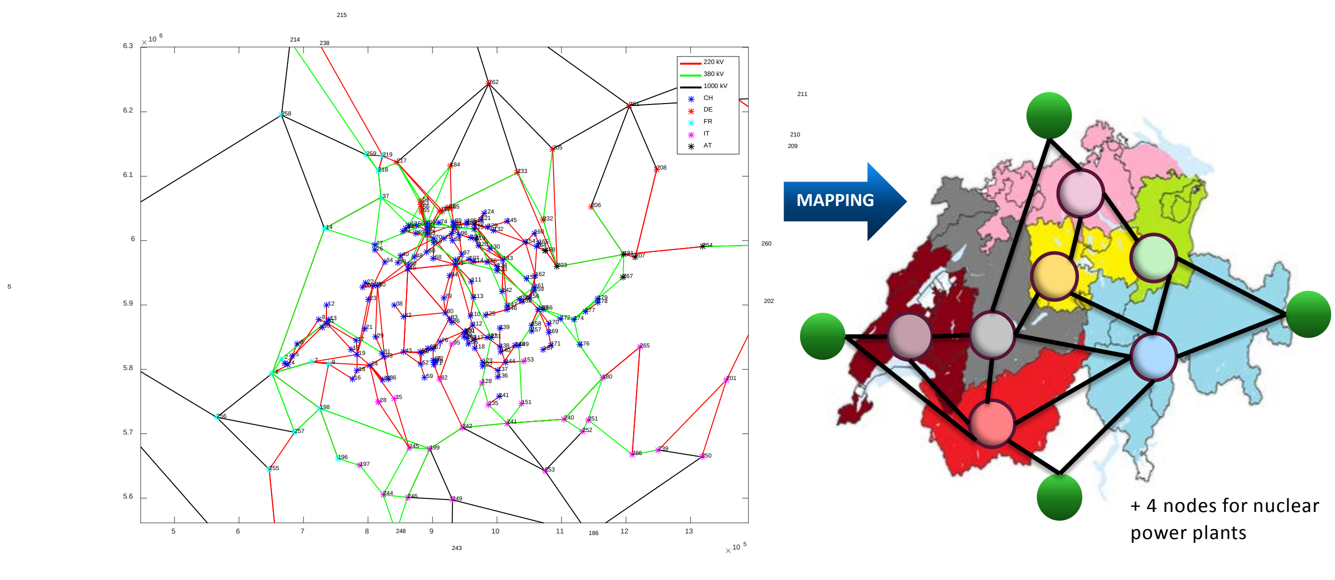


Figure 2: Reduction of the Swiss electricity grid network (left) to 15 nodes and 638 grid elements (right) used in the STEM model.

The variability of wind and solar electricity supply is captured in the model through the concept of the stochastic residual load curve (RLDC) [8] extension of TIMES [9]. According to this the storage capacity must accommodate exogenously given downward variation of the residual load curve and exogenously given upward variation of the non-dispatchable generation. At the same time, the dispatchable peak load capacity should

[2] The introduction of nuclear power plants as single nodes deemed necessary because of: a) their large power capacity; and b) the nuclear phase out policy

accommodate exogenously given upward variation of the residual load duration curve and downward variation of non-dispatchable generation. The exogenous variations were obtained by statistical analysis of historical weather and consumption data for Switzerland over the period of 2000 – 2015. Since the STEM model uses the concept of the typical day, we focused on the distribution of the mean electricity generation and consumption over the sampled years and then we moved ± 3 standard deviations in order to capture the variability in wind/solar PV generation as well as in national electricity demand.

Finally, the model endogenously captures provision of the primary and secondary reserve[3] (ancillary markets). A probabilistic approach [10] is applied to estimate the demand for each reserve type, in which the individual density functions of the random variables for electricity load and electricity production from wind and solar PV are estimated. The competitiveness of each power plant in both electricity and reserve markets is determined by its investment and operating costs as well as plant characteristics such as ramping rates and minimum stable operation levels. The trade-off between committing capacity to the electricity market versus grid balancing is based on the marginal cost of electricity production (in order to cover generation costs) and the marginal cost of capacity in the reserve market (in order to cover fixed operating and investment costs). Details in the implementation of the ancillary markets in STEM are given in [5, 11].

Definition of long-term national scenarios

A set of national scenarios was assessed, defined across two main axes of the Swiss energy strategy: (i) the gradual phase out of the existing nuclear power plants; and (ii) the long-term CO_2 emissions reduction goals. In this context two large scenario families were constructed. The P-family has exogenously given energy service demands compatible with the policies and measures of the "Politische Massnahmen – POM" scenario of the Swiss energy strategy. On the other hand, the W-family has the energy service demands compatible with the developments in the "Weiter Wie Bisher – WWB" scenario of the Swiss energy strategy. It turns out that due to the additional efficiency measures and policies assumed in the "POM" scenario of the Swiss energy strategy, the P-family of scenarios has a lower demand for electricity and heat compared to the W-family. The energy service demands used in the P-family and W-family of scenarios are presented in [12]. Table 1 gives an overview of the scenarios assessed within the project, with respect to the climate policy, nuclear phase-out and a possibility to have positive annual net import balance. For more details on the definition of the scenarios, including their main assumptions, the reader is directed to [5].

Table 1: National scenarios definitions

	Base case		*Climate change*		*Imports*		*Combined case*	
	P	**W**	**P-CO2**	**W-CO2**	**P-IMP**	**W-IMP**	**P-CO2-IMP**	**W-CO2-IMP**
POM based energy service demands	✓		✓		✓		✓	
WWB based energy service demands		✓		✓		✓		✓
Nuclear phase out by 2034	✓	✓	✓	✓	✓	✓	✓	✓
Zero net annual electricity imports	✓	✓	✓	✓				
-70% CO2 emission reduction in 2050 from 2010			✓	✓			✓	✓
Net electrcity imports are allowed					✓	✓	✓	✓

Since there are uncertainties on the location and size of new large gas turbine combined cycle plants, we also evaluated five possible locations (see Table 2) based on [13]. In this context, each one of the above scenarios has 26 scenario variants with respect to locations of gas plants. However, we present only three combinations as

[3] a) primary reserve that provides grid stability services and it is locally automated reacting to deviations to the nominal system frequency within seconds; b) secondary reserve that is automated centrally and serves to release the primary reserve for future operation by maintaining a balance between generation and demand within the balancing area for few minutes; and c) tertiary reserve that it is activated manually and only after secondary reserves have been used for a certain duration, with an activation time of up to few hours.

shown in Table 2. For example, in Case 3, total capacity of gas plant is allowed to the five location, i.e. 20% each.

Table 2: Selected cases on location and size (% of total installed capacity nationwide) for new large gas combined cycle power plants

	Corneux	Chavalon	Utzenstorf	Perlen	Schweizerhalle
Case 3	20.0	20.0	20.0	20.0	20.0
Case 11	0.0	33.3	33.3	33.3	0.0
Case 26	33.3	33.3	0.0	0.0	33.3

Results

Figure 3 presents the electricity generation mix in the W-scenario family and for Case 3 without any electricity grid expansion beyond 2025. In the "W" scenario about 3 GW of gas turbine combined cycle plants are installed by 2040 to replace the existing nuclear power plants. In addition, supply from new renewables (solar, wind and geothermal) increase and contributes to 12.9 TWh_e by 2050. The high uptake of variable RES and increased electricity supply and demand levels caused grid congestion and there deemed more storage. In this context, pump hydro produces about 5.6 TWh and batteries produce another 3.5 TWh of electricity by 2050.

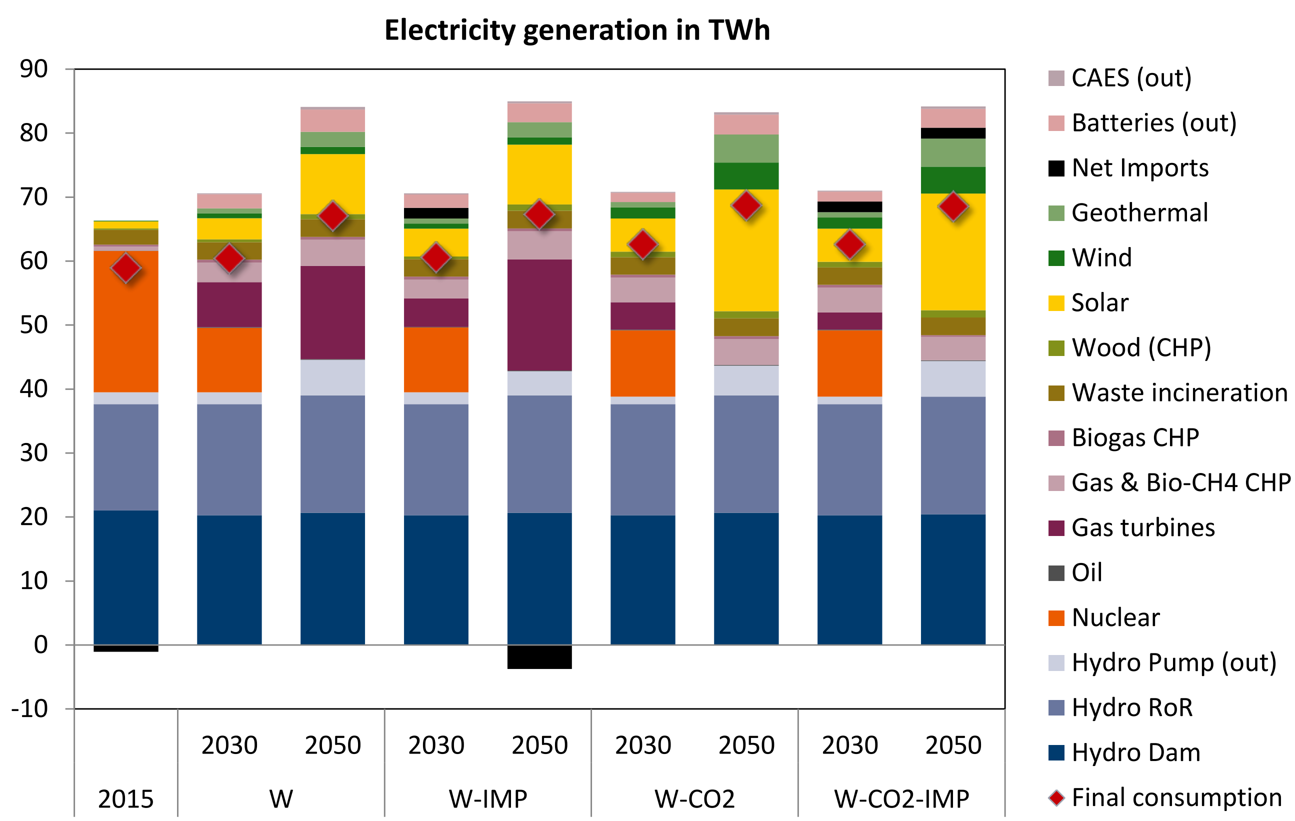


Figure 3: Electricity generation mix without expanding the electricity grid after 2025

When net imports of electricity are allowed ("W-IMP" scenario), 4.4 TWh of net exports occur in 2050. This is attributable to congestion relief at specific hours with high non-dispatchable electricity generation. In another words, non dispatchable excess electricity production is exported ("dumping") to the neighbouring countries and alleviate grid congestion. However, in the "W-IMP" scenario, storage in pump hydro and batteries are reduced by 2.3 TWh compared to the “W” scenario in 2050. The role of storage in this scenario diminishes compared to “W” due to the ability to balance electricity supply and demand with cross-border electricity trade. Also, in the “W-IMP” scenario there is increased supply from large gas based generation (plus 3.1 TWh compared to the “W” scenario in 2050). This increased gas generation is attributable to the possibility to have net annual exports of electricity and it occurs at the expense of storage options..

When strong climate policy is in place (“W-CO2” scenario), there is higher penetration of solar PV, wind and geothermal: these three options increase their electricity output by 14.7 TWh in 2050 compared to the “W” scenario. Under these high shares of variable generation, the balancing of electricity demand and supply is mainly achieved via pump storage and batteries, which have higher contribution in the electricity supply compared to the “W” scenario by 2050. At the same time, geothermal electric plants mainly provide base load electricity, partially substituting the large scale gas power plants in this role.

Similar developments are also observed in the case of strong climate policy combined with the option of annual net imports (“W-CO2-IMP” scenario). However, in contrast to the “W-IMP” scenario where net exports occurred, in the “W-CO2-IMP” scenario the increased final electricity consumption results in net imports of electricity at the expense of solar PV and CHP plants. There is still significant contribution in the electricity supply from pump storage and batteries, similar to the levels seen in the “W-CO2” scenario, from which it can be inferred that the balancing of electricity supply and demand is mainly achieved through electricity storage and not by net imports (in contrast to the “W-IMP” scenario where the contribution from pump storage and batteries is reduced compared to the “W” scenario). This implies increased arbitrage from the storage options, and especially pump storage plants, which use low cost imported electricity for pumping and re-exports at peak hours at high prices.

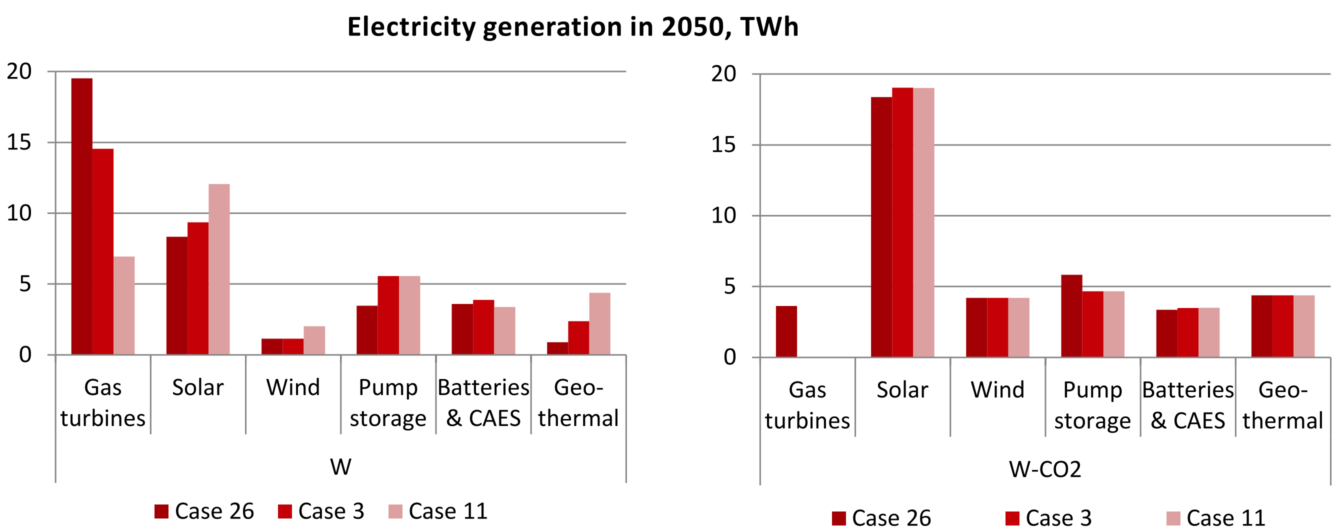


Figure 4: Differences in electricity generation across the different cases regarding the location and size of gas turbine combined cycle plants, when grid is not expanded beyond 2025.

The assumptions regarding the location of large gas power plants and the size of these power plants influence the investments in new electricity generation technologies, such as solar PV, wind, geothermal and batteries, if the electricity grid is not reinforced. Figure 4, provides additional insights regarding different allocation schemes of large gas power plants. The Case 26 has the largest level of gas based electricity supply. The increased uptake of gas turbines in this case is at the expense of solar PV and wind, due to congestion rents that reduce the cost-effectiveness of the variable renewable generation. Conversely, in Case 11 the contribution from large gas power plants in the electricity supply is at its lowest levels. This is mainly due to the grid congestion occurring in these regions, when there is no grid expansion, because of inadequate grid capacity to dispatch additional to existing hydropower and large scale gas electricity generation. Thus, additional investments in solar, wind and geothermal energy are induced, mainly in regions other than those with large gas power plants, in order to meet the demand. In Case 11, geothermal electricity plants mostly provide base load electricity in order to partially compensate the reduced output from the large scale gas plants. In addition, the increased grid congestion, the higher uptake of variable generation and the high congestion rents creating arbitrage opportunities, enable investments in electricity storage. As a result, pump hydro and batteries attain high levels of penetration into the electricity generation mix in Case 11. Finally, Case 3 stands in the middle between these two extreme cases regarding the penetration of gas turbines combined cycle in the future electricity generation mix. Case 3 allows for quite high integration of solar and wind electricity at levels close to the Case 11 (which displays the highest quantities of generation from variable renewable energy sources across all cases assessed). In this sense, under the assumption of no further grid expansion other than the one planned till 2025, Case 3 constitutes a compromise between large scale and decentralized electricity generation.

The chosen location and sizes of large gas power plants also affect the marginal costs of electricity production (Figure 5). This is because grid congestion hinders the full dispatching of large power plants in those areas in which grid capacity is scarce, which in turns allows investment and operation of more expensive options (e.g. geothermal units) in other areas with adequate grid capacity.

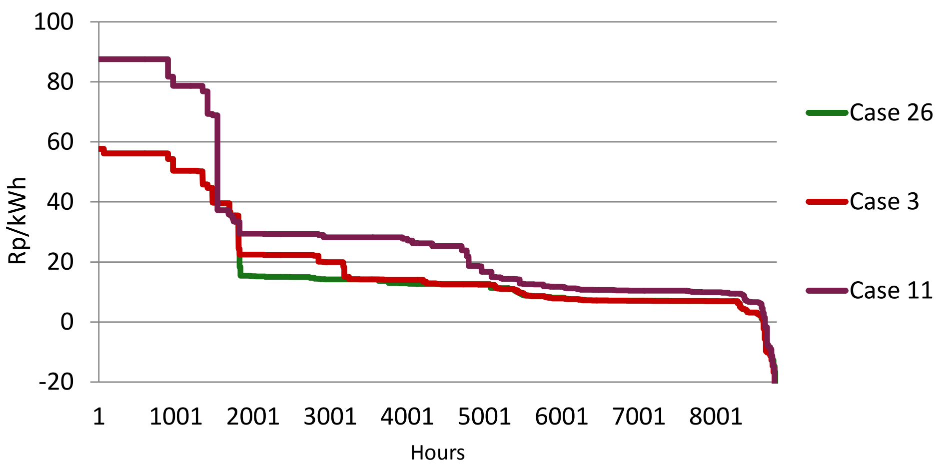


Figure 5: Marginal cost of electricity production in 2050, without climate policy

When the most congested grid line capacity is doubled (“grid expansion” alternative) then neither the location nor the size of gas plant have any impact on the optimal generation mix (Figure 6). The relief of grid congestion causes a reduction of electricity production costs, which results in fewer arbitrage opportunities for electricity storage. As a result, the electricity generation from pump storage, batteries and CAES declines compared to the no grid expansion scenario. This trend is persistent in all scenarios, regardless of the intensity of the climate change mitigation policy and the choice in location and sizes of large gas power plants. Furthermore, in the grid expansion alternative there is less or not at all generation from non-cost effective options (e.g. geothermal power) that results in additional cost savings in the power generation sector. As a result, the marginal cost of electricity is lower in this case, which leads to increased electrification of demand (+10% compared to the no grid expansion case in 2050) and, consequently, to less imported fuels for heating. Finally, when grid congestion is relieved then there is possibility to integrate higher amount of variable RES under strong climate change mitigation policy (scenarios “W-CO2” and “W-CO2-IMP”).

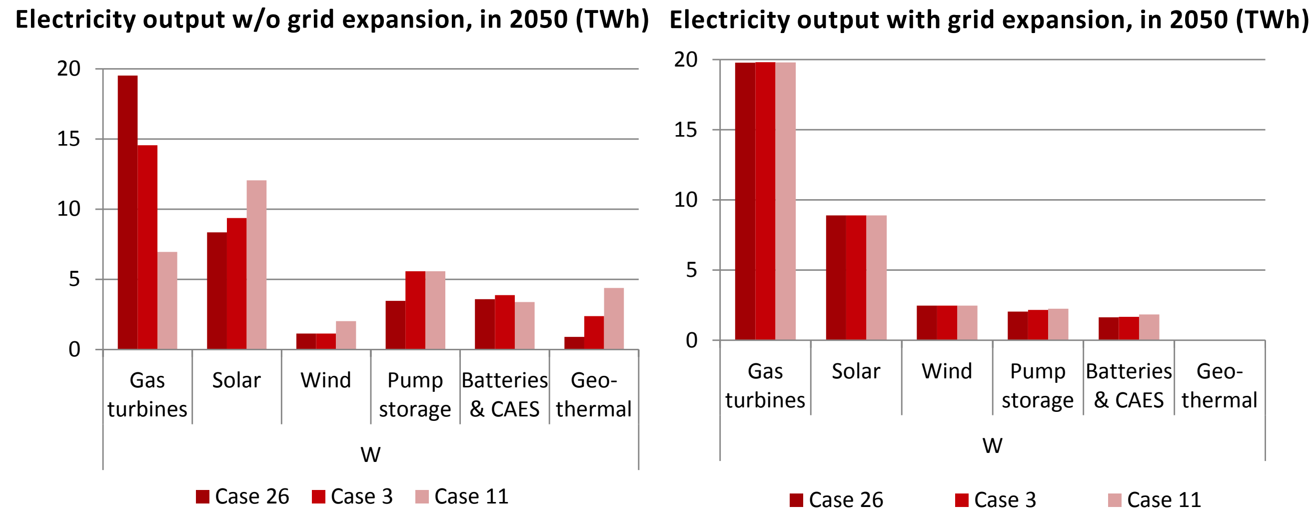


Figure 6: Electricity generation mix without grid expansion (left) and with grid expansion (right) in the "W" scenario in 2050.

The left panel of Figure 7 presents the marginal cost of electricity in case with and without grid expansion. For more than 3000 hours in a year the marginal costs are persistently higher in the no grid expansion scenario. By accounting these hours as "congested" then the occurrence of congested rents is reduced by 3000 hours per year. This leads to significant cost savings in the Swiss energy system.

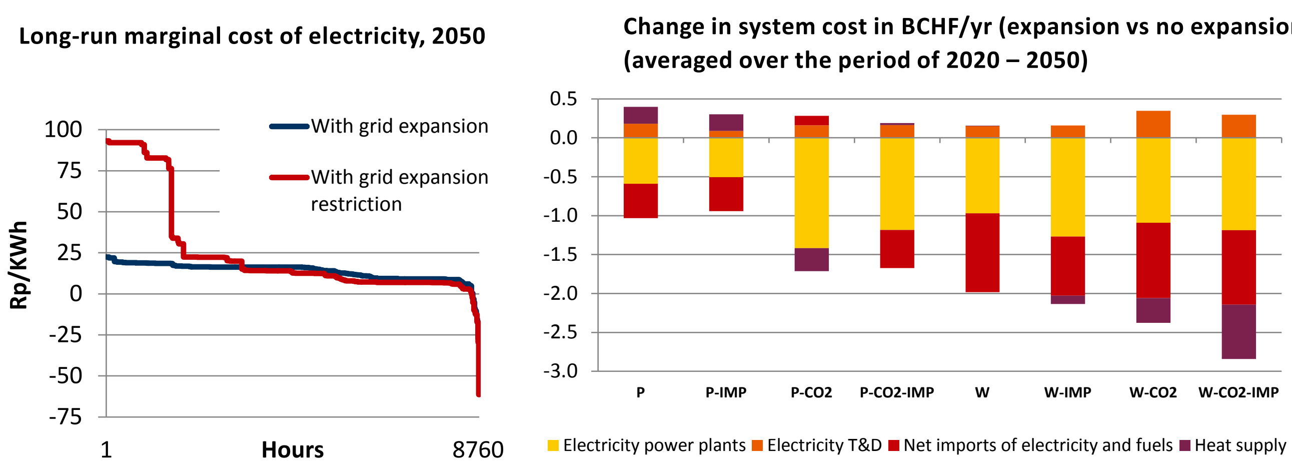
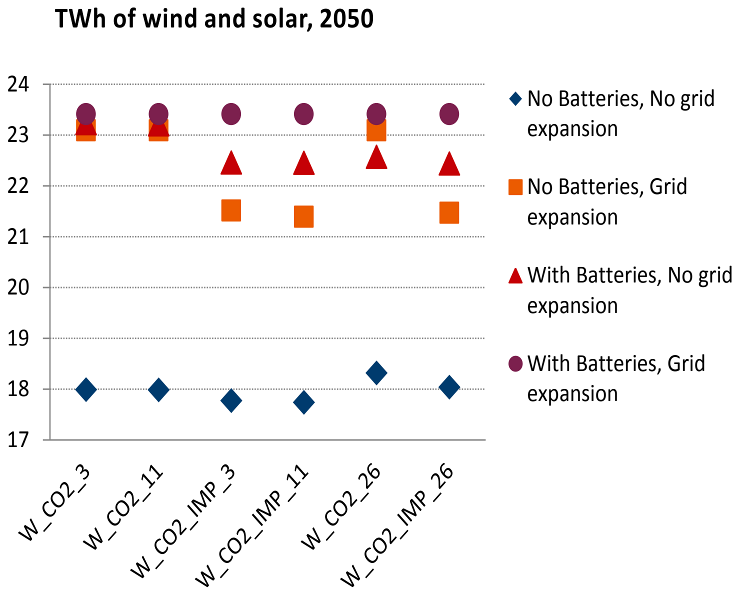


Figure 7: Marginal cost of electricity in 2050 and changes in the averaged over the period 2020-2050 undiscounted system cost in the cases with and without grid expansion.

In fact, Figure 7 on the right presents a decomposition of the cost reduction due to the grid expansion by different sectors. The figure presents the changes in the capital, O&M and fuel costs of electricity power plants ("Electricity power plants" label), the changes in the electricity T&D costs ("Electricity T&D" label), the changes in the heating supply capital, O&M and fuel costs ("Heating supply" label"), as well as the changes in costs for electricity and fuels net imports ("Net imports of electricity and fuel" label). The cost reductions mostly arise from reduced capital costs in electricity and heat supply technologies (0.02 – 1.1billion CHF/yr. on average) and from operating and fuel expenses (0.5 – 1.97 billion CHF/yr. on average). For example, with grid expansion, the residential sector invests on heat pumps and thereby avoids expensive micro CHP seen in the no grid expansion cases. In addition, increased electricity for heating uses mitigates expenses in imported fuels. Similarly, increased net imports of electricity result in less investments in domestic generation capacity. On the other hand, there are increased cost for the electricity T&D infrastructure reflecting costs due to transmission and grid access fees (due to increased amounts of electricity transferred and increased installed capacity) and investment and operating costs of the expanded line.

Despite the grid reinforcement, deployment of storage is also necessary for both integrating large amounts of variable RES and reducing overall system costs. As shown in Figure 8, when batteries are not available there is less integration of variable RES generation (about 25% compared to the opposite case) and there are also higher system costs (3 – 15% compared to the opposite case).



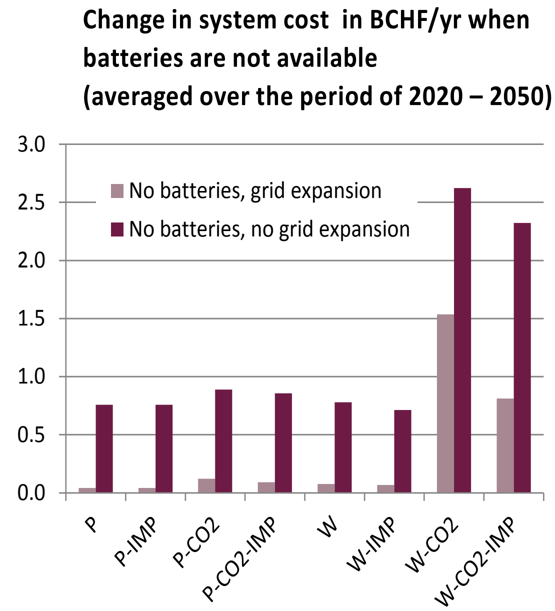


Figure 8: Impact of batteries on RES integration and costs, 2050; the numbers in the scenario names indicate the differences cases assessed with respect to the choice of the location and size of large gas power plants

On average grid congestion and increased penetration of variable RES drive the need for storage, although there are cases when grid expansion could also result in higher storage requirements. This is in the case of strong climate change mitigation policy, where grid expansion results in higher electrification of the end use sectors . This in turn leads to higher penetration of solar PV, which increases the need for distributed storage solutions. In this sense, batteries at grid level 7 correlate to solar PV and they are used about 2600 – 3400 h/yr. for charging/discharging. Batteries at grid level 5 are driven by wind and large scale solar PV and CHP plants and they mainly occur under strong climate policy (they are utilised for about 400 – 1400 h/yr.). Batteries at grid level 3 mainly complement pump storage in balancing the high voltage grid under climate policy, when pump is not available, and they are utilised for about 170 – 700 h/yr. Pump hydro operation correlates well with international trade by 2050 and it is utilised about 1000 – 1700 h/yr., while CAES is mainly used for seasonal storage.

Figure 9 presents the requirements in storage technologies as function of variable RES penetration. The need for storage increases linearly as long as the capacity of wind and solar remains less than the half of their potential capacity. There is a tipping point at around 2/3 of the potential capacity of variable RES generation in Switzerland, above which the need for storage follows an exponential-like trend.

Finally, the surplus of low-cost electricity in summer due to the increased uptake of solar PV induces investments in Power-to-X pathway, as a seasonal storage option. Driven by the electricity production cost differences across seasons, 200- 900 GWh of electricity in summer are stored in order to be used in autumn, winter, and spring in mobile and stationary applications either as hydrogen or further converted to natural gas. If grid expansion is restricted, the highest amounts of seasonally stored electricity occur in the “W-CO2” and “W-CO2-IMP” scenarios, which also show the largest penetration of renewables (thus there is excess electricity in some hours) and the highest demand (which further contributes to congestion and creates the need for electricity load shifts). It is worthy to note that about 13% of the electricity generated by variable renewable sources in summer is stored and used mainly in winter, in these two scenarios.

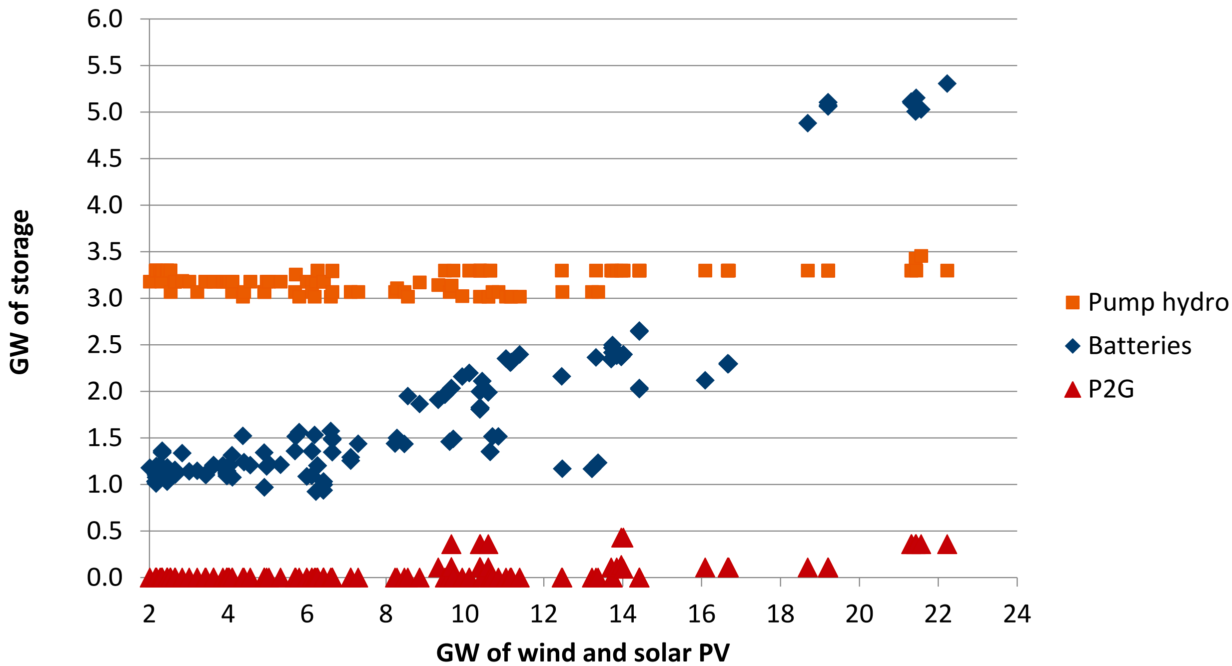


Figure 9: Requirements in storage technologies with respect to variable RES generation, 2050

Conclusions

The aim of this study is to evaluate different strategies for integrating stochastic renewable energy sources in the electricity system in the long-run. We apply an energy system model with high intra-annual resolution, representation of the variability of the wind and solar electricity production, representation of the electricity grid security constraints and ancillary markets. The results show that not accounting for the stochasticity of RES and for the grid topology in energy systems models leads to overestimation of the deployment of RES and underestimation of the requirements in storage capacity and dispatchable generation. To this end, our study makes a methodological contribution by suggesting a robust procedure to introduce both RES and load variability as well as grid topology in large scale long term energy systems models. Incorporating grid infrastructure in energy modelling provides significant benefits, because implementation and congestion costs are better reflected, including price effects, compared to the case where electricity grid topology (even at aggregate levels) is neglected.

Our results show that if there were to be no further grid expansion other than planned for 2025 [14], the congestion issues exacerbate in the longer run. This is because of higher electricity demand, but is also driven by the choice of the location and size of new build large gas-based generation, which could potentially replace today’s nuclear power. The inability of the transmission grid to integrate large gas power plants in some areas, enables investments in distributed generation, mainly solar PV, and geothermal (in those areas with good resources) as an option for base load electricity.

If grid infrastructure expansion is restricted, then in climate change policy scenarios congestion could occur even for about 7000 hours in a year in 2050. This creates arbitrage opportunities one the one hand, and requires load shifting to alleviate congestion and to balance electricity supply and demand, with substantial investments in electricity storage options. In this context, batteries offer distributed (localized) balancing solutions with a deployment potential depending on the grid level to which they are connected. The uptake of battery storage is driven by solar PV (at low voltage levels), and wind and CHP (at medium voltage levels). At the same time, batteries complement pump-hydro (at high voltage levels), in particular when the latter is not available due to water resource restrictions. In addition, the high differences in seasonal electricity production costs under climate change mitigation policy and in the presence of grid congestion enable investments in Power-to-X[4] technology as a seasonal storage option. CAES is an option for monthly storage with very region-specific deployment options (for instance only in Ticino). We find that dispatchable loads at the end-use sectors (such as water heaters and heat pumps) contribute to ease the congestion to some extent (about 12 - 18% depending on the scenario).

Our study concludes that limitations in the electricity grid expansion infrastructure can impose high costs for the electricity sector, which can be up to 3 billion CHF per year on average over the period of 2020 - 2050. This is because the limited grid capacity hinders increased electrification of the end-use sectors resulting in non-cost effective options (e.g. boilers instead of heat pumps) and imported fossil fuel costs. This is particularly prominent under strong climate policy. In contrast, when there is grid expansion, the net economic benefits can outweigh the cost. In this case, our study shows, neither the investigated locations nor sizes of large gas power plants is an issue for congestion; in this case, congestion occurrences are less by 3000 hours (or 43% lower) than the opposite case. On the demand side, needs for load shifts to alleviate congestion are also reduced if the grid is expanded. If strong climate change mitigation policy is in place, investments in grid infrastructure expansions enable to unlock the full potential to deploy new low-cost RES. This also may reduce (or postpone) the necessity to install high-cost RES (such as geothermal), which are deployed if grid congestion occurs. The long-run marginal costs of electricity are much lower, due to the more system flexibility in integrating low-cost options. This increases the final electricity consumption, especially in the climate change mitigation scenarios that in turn results in lower costs for meeting the emission targets. However, the uptake of storage options which is smaller in the case of grid expansion in most of the cases analysed.

Electricity storage is important for the integration of variable renewable energy sources for electricity generation. Sensitivity analyses in which electricity storage is disabled show that compared to the cases when electricity storage is available: a) there is on average (across all scenarios assessed) 30% less electricity from solar and wind; and on the other hand b) there is on average (across all scenarios assessed) 45% more generation from flexible gas turbines (and consequently higher CO_2 emissions). Power-to-X also is important for seasonal storage, with about 13% of the electricity generation from variable renewable sources in summer is stored for winter.

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[4] Power-to-X here refers to Power-to-H_2 or Power-to-Gas pathways including the possibility to convert H_2 or Gas back to Power

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