

## Integrating economic and engineering models for future electricity market evaluation: A Swiss case study



Jan Abrell<sup>a,b</sup>, Patrick Eser<sup>c</sup>, Jared B. Garrison<sup>d,\*</sup>, Jonas Savelsberg<sup>e</sup>, Hannes Weigt<sup>e</sup>

<sup>a</sup> Center for Energy and the Environment (CEE), Zurich University of Applied Science (ZHAW), Bahnhofplatz 12, 8400 Winterthur, Switzerland

<sup>b</sup> Department of Management, Technology, and Economics, ETH Zurich, and Center for Economic Research, ETH Zurich, Zürichbergstrasse 18, 8032, Zurich, Switzerland

<sup>c</sup> Laboratory for Energy Conversion, LEC, ETH Zurich, Sonneggstrasse 3, 8092, Zurich, Switzerland

<sup>d</sup> Research Center for Energy Networks, ETH Zurich, Sonneggstrasse 28, 8092, Zurich, Switzerland

<sup>e</sup> Research Center for Sustainable Energy and Water Management, University of Basel, Peter Merian-Weg 6, 4002, Basel, Switzerland

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### ABSTRACT

The addition of stochastic renewable resources within modern electricity markets creates a need for more flexible generation assets and for appropriate mechanisms to ensure capacity adequacy. To assess both of these issues, more cross-platform analysis is needed that can evaluate short-term reliability concerns, medium-term dispatch and price concerns, and long-term capacity expansion and market design concerns. We present an integrated modeling framework that combines a long-term investment model, a robust dispatch model of the energy market, a detailed AC network model, a novel quantification for reserves, and a rigorous evaluation of renewable energy resource potentials. We apply the framework to a business-as-usual reference case simulating the phase-out of nuclear capacity in Switzerland and a case with renewable generation targets for Switzerland. We find that the nuclear phase-out leads to a strong increase in Swiss imports. In contrast, additional renewable targets lead to a decrease of these imports. In both cases, the Swiss cross-border lines are found to be the most critical network bottlenecks and in both future cases the increased reliance on imports worsens the severity of these bottlenecks. However, the network and security assessments show no significant challenges associated with a faster and stronger renewable increase in Switzerland.

### 1. Introduction

European electricity markets are at the forefront of the global transition from fossil-based generation provision to an electricity supply dominated by renewable energy resources (RES). With about 33% of electricity generation in 2017 coming from renewable sources [1], the current EU generation mix is already heavily impacted by intermittent renewables. The envisaged further increase in renewable deployment<sup>1</sup> will continue this trend; likely making renewable energies the dominant form of electricity provision in the coming decades. This development naturally also transforms the way assessments of electricity systems need to be carried out. A high share of weather dependent intermittent renewables influences along the whole provision chain: their low variable costs influences the market price level and thereby the investment incentives for conventional generators and their dependence on weather conditions or local availabilities impacts their own investment opportunities. The weather dependent nature of wind and solar

production fed into the system can create the need for more flexible generation as well as a need for appropriate mechanisms to ensure capacity adequacy, and the altered flow patterns can increase the burden on grid operators to ensure robust and reliable system operation.

To assess these different dimensions a cross-platform analysis is needed that can evaluate short-term reliability concerns, medium-term dispatch and price concerns, and long-term capacity expansion and market design concerns. However, many energy models underlying the ongoing political decisions (e.g. the reference scenario of the European energy trends [2], the energy perspectives of the Swiss Energy Strategy 2050 [3], or the Energy Reference Forecast for the German Federal Ministry for Economic Affairs and Energy [4]) are falling short in providing this comprehensive picture. While this is mostly a result of the inherent trade-offs in modeling between sufficient level of detail and computational as well as data availability limitations, there are nevertheless multiple models and model approaches available that can

\* Corresponding author.

E-mail address: [garrison@fen.ethz.ch](mailto:garrison@fen.ethz.ch) (J.B. Garrison).

<sup>1</sup> The overall EU target for RES in final energy consumption by 2020 is 20% and target for 2030 has been increased to 32% in the latest Renewable Energy Directive.

provide the needed elements for a comprehensive assessment. Often those more specific models are using reference scenarios to provide insights on sub topics like network extensions (e.g. the German grid development plan) or system adequacy (e.g. by the Swiss Federal Office of Energy [5] and the Swiss Federal Electricity Commission [6]). A consistent coupling of those different model layers and cross-disciplinary approaches covering the technical, market and policy aspects enhances the current decision making by providing consistent long- and short-term assessments on investments, operation and security aspects.

In this paper we take up this challenge by presenting a coupled model framework [7] addressing the main caveats when assessing future electricity markets. The framework combines modeling of renewable supply with a high temporal and spatial resolution with detailed modeling of electricity markets with a particular emphasis on short-term market mechanism such as balancing markets and network security aspects. Long-run investment modeling complements this modeling of the short-term aspects in an integrated manner. We calibrate the framework to the Swiss electricity system and showcase its suitability to provide a comprehensive evaluation of the most relevant criteria for policy makers and stakeholders.

The remainder of this paper is structured as follows. The next section describes the state of the literature with regards to energy and power systems modeling, as well as the unique contribution of the present work to the literature. Section 3 provides the overall modeling framework and explains its respective elements and linkages in the context of renewable dominated electricity market assessments. Section 4 provides the specifications for its implementation in Switzerland. In Section 5, a test assessment for the future development of the Swiss electricity market is presented and compared to the official Energy Strategy 2050 scenario setting. Section 5 summarizes and concludes.

## 2. Model approaches for electricity system assessments

As described in the introduction, a comprehensive analysis of the impacts of increased RES penetration on electricity systems requires the application of a multi-timescale modeling framework. A short-term (sub-hourly to hourly) power systems model is required to analyze the impact of fluctuating RES generation on power plant cycling, transmission system adequacy and reserve market design. A medium-term (yearly) dispatch model is needed to optimize the production of cascaded hydropower facilities, and to investigate the market valuation of energy generation and production capacity for future scenarios. A long-term (multi-yearly to decadal) energy systems model is further required to endogenously determine investments into new generation capacities in future years, which provides the dispatchable generation fleet as boundary condition for the short-term and medium-term models.

Many different methodologies that investigate the impact of RES penetration on electricity systems have been presented in literature. A comprehensive overview of existing modeling approaches is provided by Ringkjøb et al. [8]. Prior works applying these methodologies typically have focused on one, and not all three, temporal dimension of electricity systems analysis. The impact of fluctuating RES on short-term power system operation is mostly investigated with power systems models, such as MATPOWER [9] and PLEXOS [10]. MATPOWER uses an optimal power flow (OPF) approach to simulate the physical flow of power through a given transmission system. While being suited to investigate the impact of renewable power on network contingencies, as shown in Hitaj [11], MATPOWER is not suitable for long-term investment analyses. The proprietary software PLEXOS is capable of including long-term investment decisions into short-term OPF simulations, but many studies using PLEXOS focus on simulation horizons of one year or less, for example Foley et al. [12]. The medium-term operation of power systems with increased RES penetration is commonly investigated with security-constrained unit commitment approaches. Such analyses, for example Wang et al. [13] and Norouzi et al. [14], enable finding a realistic dispatch response of conventional and hydro

generators to increasingly variable RES generation. At the same time, such analyses omit long-term investment decisions, and hence do not endogenously incorporate the gradual transformation of the generation portfolio over time. The long-term development of power systems under increased RES influence is also investigated in several prior works, many using the publicly available energy systems models MARKAL [15], TIMES [16] or EnergyPLAN [17]. While these tools use partial equilibrium models to assess the future development of the electricity sector over several decades, they omit issues regarding short-term power system operation. A comprehensive list of studies applying MARKAL for different long-term energy system studies is provided by Taylor et al. [18].

A number of prior works have coupled several models of different timescales to comprehensively address the impact of increased RES generation on electricity systems. One approach that soft-couples a short-term power systems model with a long-term energy systems model was presented by Deane et al. [19], where the energy systems model TIMES is coupled with the power systems model PLEXOS to investigate the Irish power system under increased RES penetration. While this work successfully uses the results of a power systems model to better understand the implications of RES penetration on overall system adequacy, it does not model the physical transmission infrastructure of the studied power system. This is a shortcoming, as the sufficiency of the transmission system is a key determinant for RES curtailment and system stability [20]. A similar approach, which couples a long-term TIMES model with a short-term in-house power systems model, has been applied for the UK for scenarios up to 2050 [21]. Compared to [19] this work does resolve the geospatial inhomogeneity of RES generation, yet still omits to resolve the power system down to the level of individual transmission lines.

In light of the shortcomings of the prior studies, a novel, comprehensive simulation framework is developed in this work to investigate the future of the Swiss electricity market up to the year 2050. The framework explicitly captures the aforementioned three (short-, medium- and long-term) temporal dimensions by coupling a power systems model with a dispatch model and an investment model. The inclusion of all three temporal levels is crucial for this work, as it enables 1) the identification of bottlenecks in the Swiss transmission grid, 2) the market-realistic dispatch of the hydropower sector, which accounts for 60% of Switzerland's electricity supply and 3) the assessment of long-term developments of conventional generation portfolios in Switzerland's neighboring countries, which could substantially impact the Swiss electricity market in the future.

## 3. A model framework for comprehensive electricity market assessments

As indicated in the previous sections, there are different challenges associated with future electricity system developments that a model framework needs to be able to cope with. In this section we want to introduce our concept for a comprehensive evaluation scheme coupling a set of model and data approaches that we deem essential for model based assessments. In particular we consider the following dimensions as crucial for a comprehensive assessment:

1. Renewable potential and uncertainty: providing the basis for a correct assessment of the different challenges associated with increasing renewable penetration
2. The long-term perspective: covering investments and the impact of policy and market design on a scale of several decades
3. The short-term perspective: addressing hourly and sub-hourly system operation and the impact of variable renewable generation on dispatch and power flows
4. System stability: identifying network stability and reserve requirement constraints by resolving bottlenecks within the physical transmission system

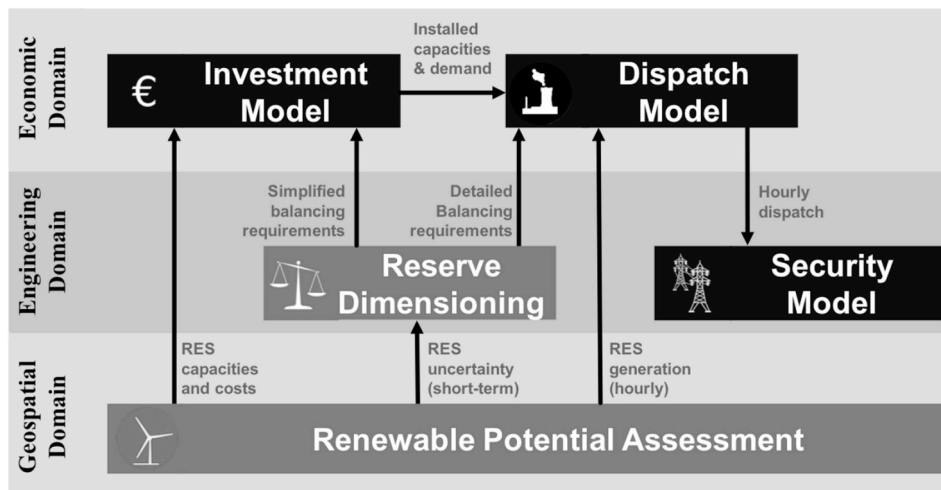


Fig. 1. AFEM modeling framework.

Translating these requirements into a workable model framework leads to a linked cluster of different models and data assessments as shown in Fig. 1. Given the different requirements, the framework needs to combine aspects from the geospatial domain providing the needed detailed renewable assessment, the engineering domain providing the security related assessments, and the economic domain providing the market and policy structures for the long- and short-term assessments. The concept of the framework is a linkage of individual models and approaches instead of an overarching single model addressing all dimensions. Thereby the expertise from the different fields can directly be used by building upon available assessments and model designs.

The central assessment of potential future electricity system developments will be carried out by a chain of three models (darker grey elements in Fig. 1). The underlying model approaches for each layer are build upon the vast existing modeling literature (see Section 2).

First an *investment model* optimizes the capacity additions over the time horizon of interest (e.g. 2020 to 2050) accounting for the desired market and policy framing (e.g. energy-only market, capacity market approaches, RES support policies, etc.). The investment model transfers the resulting power plant capacities and demand levels to the *dispatch model*. This model layer provides the short-term market results (e.g. on hourly resolution for a year or representative weeks) and therefore should include all important market dimensions: the direct energy dispatch (i.e. including unit commitment aspects if needed), network and trading related constraints (i.e. flow based NTC trading or a full nodal DC-load flow approach), and balancing and reserve market aspects (i.e. primary, secondary and tertiary reserve requirements). Finally, the dispatch model results are transferred to the *security model* performing a system stability assessment. This model layer will assess the transmission system impacts and reserve performance of the market dispatch. This requires a full AC load flow simulation of the investigated system and can be seen as a model equivalent of the real-world re-dispatch and imbalance management of system operators. A central element of this layer should be the assessment of N-1 simulations.

Albeit the exchange of data along the model chain is mostly one-way, there is nonetheless a need for feedback between the models to ensure consistency across the framework. As the investment model will usually have a higher aggregation than the dispatch model (e.g. aggregated national capacity values, reduced time resolution), a consistent approach for disaggregating the investment results will be needed. Also, the resulting indicators like average wholesale prices and import/export structures need to be compared between the two model layers and in case of significant deviations be addressed accordingly. Similarly, the dispatch model and security model should be operated on a consistent and coordinated dataset to ensure that any deviation identified in the security assessment stems from market driven aspects

(e.g. not accounting for the full network on the wholesale level) and not from data inconsistencies.

This model chain needs to be backed up by and provided with crucial inputs from two data-oriented layers (lighter grey elements in Fig. 1), which call upon expertise from geoscience and engineering.

The fundamental basis for the assessments needs to be provided by a detailed *renewable potential and dynamics assessment* based on geospatial approaches. Given the dependence of most renewable generation technologies on local factors, a detailed Geographic Information System (GIS) analysis will be needed that accounts for natural and anthropogenic constraints that have an impact on the suitability of locations for renewable deployment. Those need to be coupled with detailed weather and climate information to obtain distributions for wind speeds and solar radiation. The increasing dominance of RES in the electricity system calls for a more extensive inclusion of those aspects into the assessment structure. Whereas fossil-based structures mostly rely on average cost and provision structures as they are less locational dependent, a similar average-based approach for renewables could easily result in significant over- or underestimations of the real system impacts. The renewable assessment will need to provide potential extension capacities and respective investment costs for the investment model as well as the short-term availability of the installed capacities for the dispatch model. Consequently, the main challenge is the translation of those detailed GIS-based assessments into input structures for the model layers.

The second data assessment layer addresses the system stability aspects. Short-term system stability is provided by reserve markets or requirements in backup provision in most systems. Consequently, the main focus of this data layer lies on *reserve dimensioning* approaches to quantify the amount of reserves necessary to compensate for added intermittent generation from wind and solar power. Reserve dimensioning in nuclear-fossil systems was based on short-term demand variation and outage risk (i.e. outage of the largest power plant of the system). With a transition to a supply based on mostly small-scale renewable generators, the outage risk is less important and the distribution of forecast errors becomes crucial. Consequently, the reserve dimensioning will require assessments on the renewable uncertainty from the renewable assessment layer and in turn provide the respective balancing market requirements for the dispatch model. Ideally, the investment model would also include at least an aggregated representation of the balancing aspects in which case it would also need inputs from the balancing data layer. Finally, the balancing assessment in the security model will be directly linked to the reserve dimensioning evaluations and consequently both layers will need to be closely coordinated.

This framework enables assertions regarding the impact of

renewable integration on the generator fleet dispatch, system flexibility needs, and on the security and stability of the high voltage transmission network. Thereby, the framework would enable solid evaluations of proposed solutions for the two primary challenges facing electric system operators during the move towards higher shares of renewable energy resources:

1. How can liberalized electricity markets provide proper economic incentives to achieve adequate investment in new generation capacity?
2. To what extent are new sources of temporal and spatial flexibility needed to enable higher penetration levels of stochastic renewable resources?

Being designed to be built upon existing approaches and coupling those it furthermore represents a straight forward extension of the existing assessment tools ensuring a workable implementation and scalability to the respective system(s) under investigation. Thereby it is suitability for (policy) decision making that is often time and resource constrained.

Nevertheless, the proposed framework still has limitations. Besides potential model-based restrictions that depend on the actual model designs and linkage implementations, the main limitation is the focus of the model chain on the wholesale and transmission layer. Given the distributed and small-scale nature of wind and especially solar generation, they can be expected to have a significant impact on and in turn depend on distribution grid constraints. While the GIS-based renewable assessment can include part of this dimension (e.g. accounting for distribution grid connection) the model layers are usually not accounting for distribution grid aspects. While they could in principle be added to the respective assessment layers, we neglected them for this framework because of the usually high data limitations. Whereas national electricity system models and transmission network representations are readily available by now, sufficiently detailed representations of distribution grids are still lacking.

#### 4. Model specification for Switzerland

Following we will implement the above presented framework for an assessment of the Swiss electricity market. The Swiss market, like most European electricity markets, aims at transforming its current nuclear and hydro dominated supply structure into a renewable based system (see next Section for details). Being at the center of Europe's electricity system, Switzerland has the role of an important transit hub between North and South Europe. Consequently, network related aspects like import and export structures, congestion, and network extensions play an important role for the future system development.

Using this test case we apply the assessment framework building upon the existing Swiss electricity market model Swissmod, developed by Schlecht and Weigt (2014) [22], as central dispatch element. The investment model will be using an aggregated version of the dispatch layer keeping the hourly time resolution. This ensures a high consistency between the two model layers and avoids the need for iterative feedback structures. Similar, the security model builds upon the network structure of Swissmod to ensure the resulting flow assessments are consistent and differences stem solely from the more detailed AC-load-flow modeling of the security model.

The overall data flow follows the structure presented in Fig. 1. The investment model provides yearly capacity values for each technology to the dispatch model which in turn provides hourly generation and demand levels to the security model. All models draw on a common data pool for generic system data like fuel costs, neighboring countries capacities, demand levels and hourly profiles. Renewable specifications and reserve requirements are derived by the respective data layers.

We continue by first describing the formulation of the three model layers (investment, dispatch, and security). Afterwards, we describe the

underlying data basis and how the respective models are calibrated. A fully detailed description of the Swiss model framework is provided for further transparency in the underlying project working paper [23].

##### 4.1. Investment model

The investment model formulation for Switzerland simultaneously determines electricity generation within and trade across the modeled countries (*c*) (Switzerland and its neighboring countries). In each region, hourly electricity demand as well as demand for balancing reserve can be satisfied by conventional generation technologies (*i*) and renewable power technologies (*r*). Investments into capacities are taken as given for surrounding regions and calculated endogenously for Switzerland. The model covers the years (*y*) from 2015 up to 2050 in five-year steps. For each year, we use an hourly resolution of the full year, i.e., 8760 h (*t*) per year, to ensure a close linkage to the dispatch model. The objective of the investment model minimizes system operation cost defined as the sum of dispatch and investment costs.

$$\min C = \sum_{i,c,y} [\sum_t [(c_{icy}^0 + c_{icy}^1 Q_{icyt}) Q_{icyt}] + c_{icy}^i CAP_{icyt}] + \sum_{r,c,y} \left[ (c_{rcy}^{R,0} + c_{rc}^{R,1} Q_{rcy}^R) Q_{rcy}^R - (c_{rcy}^{R,0} + c_{rc}^{R,1} Q_{rc(y-1)}^R) Q_{rc(y-1)}^R \right] \quad (1)$$

Costs for conventional power plants (first block) are characterized by a quadratic cost function for their output (*Q*). This quadratic cost function reflects the variety of the heat rates of the plants represented in a technology class assuming that most efficient plants are dispatched first. Coefficients of the cost function ( $c_{icy}^0$  and  $c_{icy}^1$ ), therefore, reflect the different heat efficiencies of plants as well as the changes of fuel and carbon prices over the years. The output accounts for provisions of balancing reserve and is subject to the usual capacity constraints. Cost for investment into installed conventional capacity (*CAP*) are expressed in terms of annualized investment cost.

Costs for renewable power plants (second block) are characterized by increasing costs following the suitability of the respective installation sites using a quadratic cost assumption. We postulate that renewables are invested at the most favorable sites first (see Section 4.4.1 for details). Renewables cost are expressed as annualized investment cost per energy. Due to exogenous technological progress, renewable investment costs are decreasing in time (i.e. the cost intercept ( $c_{rcy}^{R,0}$ ) is decreasing in the year (*y*)). This cost decrease is reflected by deduction over years: the costs of the added renewable production in any year is derived by calculating the costs of the total output and deducting the costs of the output of those units already being installed in the previous year. Both, total installed conventional capacities and total renewable production, is limited by their respective potentials.

We assume a fixed demand and include demand for balancing provision. The latter depends on the amount of installed renewable energies following the logic identified in the reserve dimensioning layer (Section 4.4.2). As Switzerland generation is heavily dominated by hydropower we distinguish three hydro plant types: run-of-river (RoR) plants, hydro dams (DAMs) and pumped storage (PS) facilities. Capacities of all hydro facilities are exogenously given, i.e., we do not model investment decision into storage facilities. All hydro facilities produce with zero generation cost but storing electricity is associated with losses. The RoR plant has no storage capacity and an externally defined availability profile. The DAM plant has a yearly output restriction representing the inflows to the storage. The PS facilities account for changes on their storage level depending on their pumping and turbination (see Dispatch model for details).

Trading between the regions is modeled with a direct current (DC)-loadflow approach similar to the dispatch model (see Section 4.2). The underlying electricity grid represents a reduced form version of the more detailed grid used in the dispatch model. As the main simplification compared to the dispatch model, each region is represented by one node in the grid, i.e., we abstract from inner country congestion in

the investment model. The country nodes are connected via aggregated lines representing the cross-border lines between Switzerland and the neighboring countries.

Given the objective function and constraints, the model computes the cost-optimal solution to fulfill demand. In general, there are two ways to satisfy demand: First, use the existing power plant fleet. Second, invest into new generation capacities, either renewable or conventional. The optimal amount of investment is determined by trading-off these two options which are reflected in the first and second line, respectively.

The model is formulated as a quadratic problem, i.e., a quadratic objective function over a linear constraint set, in GAMS. CPLEX is used to find the optimal solution. A single scenario run solves in about one hour.

#### 4.2. Dispatch model

The dispatch model is based on the Swissmod-model developed by Schlecht and Weigt (2014) [22] and has been tailored to allow for an in-depth analysis of possible future market designs in Switzerland. Taking the installed capacities from the investment model for the respective years, the dispatch model optimizes the dispatch for a single one of these years based on a nodal Swiss electricity system using the DC load flow representation (see e.g. [24], Stigler and Todem 2005 [25,26]). Besides the detailed Swiss system, it incorporates an aggregated representation of the surrounding countries. Given the high share of hydro power generation in Switzerland, the model encompasses a detailed representation of hydropower elements, distributed demand and generation, and detailed grid structures as well as a representation of balancing markets.

The dispatch model follows state of the art dispatch model approaches and is designed as a cost minimization problem (using a quadratic cost function derived from data on power plant efficiency, fuel and carbon prices) accounting for the usual capacity and power flow constraints. Renewable infeed is exogenously derived following the data provided by the RES potential assessment and the capacities provided by the investment layer. The model allows for load shedding and curtailment of feed-in from renewables. The model furthermore accounts for combined heat and power production constraints. The market is cleared for each time step and at each node using a nodal energy balance with inelastic nodal demand. The marginal or dual variable on the energy balance can be interpreted as the hourly nodal price.

Compared to other dispatch models like [26,27] our model has two specificities relevant for the Swiss market and the assessment of renewable generation: a detailed representation of the Swiss hydropower sector and a representation of the balancing requirements.

Hydro power plants in Switzerland are connected to virtual water-nodes, which represent upper and lower storage lakes or rivers (Fig. 2). Together, nearby waternodes and hydro power plants form cascades, which allow for the representation of the interaction between consecutive hydro power plants and storage lakes. The storage level at each waternode  $Stor_{wn,t}$  is defined as the sum of the storage level in the previous time period and water inflows  $WI_{wn,t}$  less water outflows  $WO_{wn,t}$  in the current time period:

$$WI_{wn,t} = inj_{wn,t} + \sum_{h \in lowerwn} Turb_{h,t} + \sum_{h \in upperwn} Pump_{h,t} \quad (3)$$

In situations where more water is available than can be used plants are allowed to spill excess water to downstream water nodes. Some

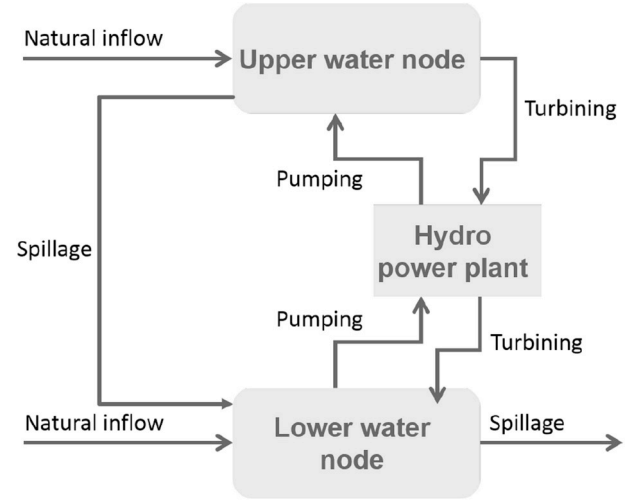


Fig. 2. Stylized representation of a hydro cascade and water in- and outflows as used in AFEM-Model.

$$Stor_{wn,t} = Stor_{wn,t-1} + WI_{wn,t} - WO_{wn,t} \quad (2)$$

water nodes are directly connected to downstream water nodes and are allowed to transfer water from one waternode to the next by direct transfer. Water outflows are defined accordingly:

$$WO_{wn,t} = \sum_{h \in upperwn} Turb_{h,t} + \sum_{h \in lowerwn} Pump_{h,t} \quad (4)$$

The maximum storage level of each waternode is limited by its maximum storage capacity with rivers having a storage capacity of zero.

Generation and pumping by hydro power plants in surrounding countries are modeled on a more aggregated level. Run of river plants are given a monthly generation profile, while yearly per country constraints are defined for generation by (pump) storage power plants. Storage levels  $Stor_{count,t}$  for these plants are defined as the sum of the storage level in the previous period less turbinning in the current period plus pumping in this period:

$$Stor_{count,t} = Stor_{count,t-1} - Turb_{habroad,t} + Pump_{habroad,t} \quad (5)$$

All hydro plants are constrained by their respective turbine, pump and storage capacity.

The model encompasses the representation of positive and negative balancing reserves and energy on secondary and tertiary markets ( $m$ ). In order to provide positive balancing reserves  $B_{m,t}^+$  conventional power plants ( $conv$ ) can offer to increase generation, while hydro power plants ( $hydro$ ) can either offer to increase their generation or to decrease their pumping:

$$bal_{m,t}^+ = \sum_p B_{p,m,t}^{+conv} + \sum_h B_{h,m,t}^{+hydro} + \sum_h B_{h,m,t}^{+hydro\ pumpless} \quad (6)$$

Similarly, negative balancing  $B_{m,t}^-$  can be provided by reducing generation by conventional or hydropower plants or by increasing pumping:

$$bal_{m,t}^- = \sum_p B_{p,m,t}^{-conv} + \sum_h B_{h,m,t}^{-hydro} + \sum_h B_{h,m,t}^{-hydro\ pumpmore} \quad (7)$$

Balancing energy provided by each power plant is the result of capacity bids and the eventual callup of positive and negative balancing energy. The total amount of positive balancing reserves provided by conventional power plants is limited by their energy market production and their available capacity:

$$Q_{p,t} + \sum_m B_{p,m,t}^{+conv} \leq q_p^{max} \quad (8)$$

whereas negative balancing is limited by their energy market production only:

$$Q_{p,t} \geq \sum_m B_{p,m,t}^{-\text{comp}} \quad (9)$$

Balancing reserve provision by hydro power plants through an increase (decrease) in generation or pumping follows a similar logic. The marginals on the positive and negative balancing constraints can be interpreted as the price for balancing reserve provision on the respective market.

The model is formulated as a quadratic problem, i.e., a quadratic objective function over linear constraint set, in GAMS. CPLEX is used to find the optimal solution. A single run for one year and one scenario takes about 2–3 h, depending on the scenario specifications.

#### 4.3. Security model

Taking the hourly nodal demand and generation values from the dispatch model, the security model is used to assess system security indicators such as voltage violations and N-1 risks as well as to quantify reactive power flows and line loadings. The Security modeling layer uses a comprehensive alternating current (AC) network model of the Swiss transmission system built in MatPower [9] to assess the security and reliability of the grid infrastructure as well as evaluate the need for additional flexible generation resources and future transmission system improvements. We consider only the steady state operation of the power system, i.e. transients and reserve deployment dynamics are assumed to be settled.

The Security evaluation follows a three step process. First, a DC power flow consistency check is performed. Taking the DC-based dispatch from the dispatch model layer a DC simulation of the security model environment is performed. The results of this test ensure consistency of the modeled system and parameter details between the Dispatch and Security layers.

The second step in the Security model layer is to convert the DC-based dispatch results into a feasible AC dispatch. A constrained optimal power flow is used that sets each generator's minimum generation level in a given hour  $q_{p,t}^{\min}$  equal to the desired Dispatch Model-based generation level  $Q_{p,t}^{DM}$ :

$$q_{p,t}^{\min} = Q_{p,t}^{DM} \quad (10)$$

For Swiss generators, the maximum generation levels  $q_{p,t}^{\max}$  are set based on the known maximum generator capacities  $Cap_p^{\max}$  and each generator's upward reserve procurement from the Dispatch Model's results  $B_{p,m,t}^{+,DM}$ :

$$q_{p,t}^{\max} = Cap_p^{\max} - \sum_m B_{p,m,t}^{+,DM} \quad (11)$$

This maximum level allows increased generator injections (above the desired amounts from the Dispatch Model) in a given hour but ensures that all generator capacities held back as a reserve will still be held. Such increased generation amounts are essential since the AC Security model includes power losses in the transmission system on the lines inside Switzerland and crossing the Swiss border. For all non-Swiss generators, the electricity production in each hour is fixed:

$$q_{p,t}^{\min} = q_{p,t}^{\max} = Q_{p,t}^{DM} \quad (12)$$

Additionally, the power injections from any renewable generators in the surrounding countries is fixed to exactly match the hourly amount set in the Dispatch model layer, while those in Switzerland are allowed to be curtailed. By tracking metrics, such as the line loading level, this step of the security model layer will highlight areas of the transmission system that become more congested or tend to operate closer to their limits. Additionally, this analysis will provide insights into the amount of power needed to make up line losses and which Swiss generators tend to be used to provide this extra power. The AC-OPF also provides information about the reactive power flows and voltage levels across

the system. Running a single hour's ACOPF using IPOPT with the linear solver PARDISO [28–30] takes around 1–2 s to solve; therefore, parallelization of the 8760 h was required to complete a full years simulation within 30 min.

In the last step the feasible AC dispatch is used as a basis for an N–1 security analysis. This process is completed using an iterative AC power flow where all appropriate line and transformer contingencies are considered for each hour of the year (i.e., a minimum of 257 contingencies and 8760 h yields over 2.2 million ACPFs for simulating one year). The results will highlight line contingencies that tend to cause further overloadings or voltage violations as well as highlight those lines (or nodes) that tend to be overloaded (or overvoltage) as a result of a contingency. Since this method does not use a security constrained OPF, the security level of a base case calibration is used as a benchmark. By comparing the security model layer results of other scenarios to those of this benchmark, the impacts on the system security can be determined for all other scenario changes. Parallelization of this N–1 simulation was essential and resulted in a simulation time of around 3 h when spread across 10 separate cores.

#### 4.4. Data provision

Following the model framework in Fig. 1 we will first provide details on the two detailed data layers of the framework and afterwards provide a short overview on the generic external data underlying the whole model chain. Two different approaches have been used for the representation of power plants, grid structures and regional demand patterns. For Switzerland a detailed nodal approach is used in the dispatch model and the security layer whereas neighboring countries are represented using an aggregated per country structure. For the investment model, all nodal information is aggregated to a per country level.

##### 4.4.1. Renewable potential assessment

As **hydropower** is the most important domestic source of (renewable) energy in Switzerland the underlying dataset includes the 419 largest hydro power plants with power plant specific information taken from the statistics on hydroelectric installations in Switzerland [31] as well as 214 storage lakes in Switzerland and their storage capacities. Based on HydroGIS developed by [32], hydro cascades have been derived showing the inter-connections of hydro power plants and watermodes. Power plant specific conversion factors from water units (cubic-meters) to energy units (MWh) for turbinning and pumping have been calculated using information on power plant specific installed turbinning (pumping) capacity and the maximum water flow capacity through the respective turbine from [31]. Monthly inflows in water units for each cascade have been derived from the discharge and catchment area dataset from BAFU [33] in combination with spatial information on the extent of catchment areas per cascade from [32]. In combination with the information on cascade structures, power plants and storage reservoirs, this allows for a realistic representation of seasonal water values available for each power plant over the entire year. The fully detailed hydro-dataset forms the basis of the dispatch model and is aggregated for the investment model.

To evaluate and optimize the **wind and solar photovoltaic** (PV) resource potentials in Switzerland, a detailed Geographic Information Systems (GIS) analysis is applied over all land areas (for wind) and all rooftops (for PV) of Switzerland. The use of GIS enables us to account for the distribution of natural and anthropological constraints necessary to identify the location of suitable regions for wind projects and PV modules. Basic data on the suitability of regions for wind and rooftop surfaces for PV are provided by the Swiss Federal Office of Topography [34]. In addition to these swisstopo data, a wide range of climate data have been collected, analyzed, and validated to produce the spatial distribution of the wind speed and solar irradiance characteristics across Switzerland [35].

The methods used to quantify the economically attractive wind and PV installations in Switzerland both include three steps. First, the theoretical

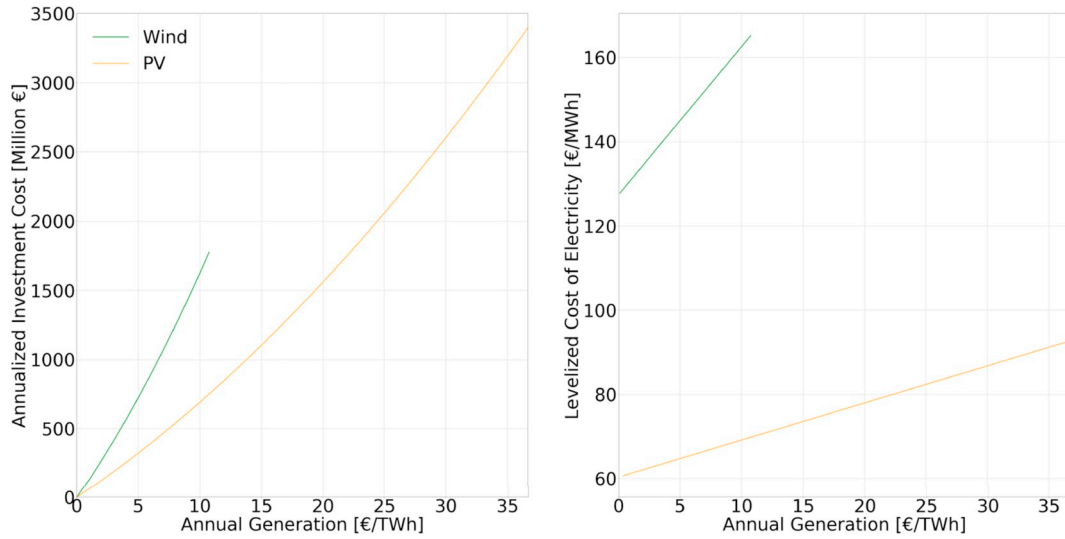


Fig. 3. Annualized renewable investment costs.

resource characteristics across all land areas (wind) or rooftops areas (PV) are estimated. Second, areas that are technically infeasible for the development of the wind or PV projects are eliminated based on a GIS assessment. Lastly, for all feasible areas the economically attractive potential is evaluated using the resource characteristics, assumed economic input parameters, and a user-defined threshold for the internal rate of return (IRR). The results yield the location and magnitude of wind and PV capacity that are both technically feasible and economically attractive [36–46]. As part of this economic evaluation step, additional processes are applied to the wind and PV evaluation. For wind, optimization of the number of wind turbines placed on each single land area is performed while simultaneously accounting for the wake effect of having multiple wind turbines. For PV, the rooftop slope and shading from surrounding objects are considered to yield the rooftop space functional for PV modules.

The assessments for both wind and PV potential are conducted for numerous feed-in-tariffs (FIT) and interest rate ranges (FIT from 0 to 50 cents/kWh; interest rate from 1.5% to 4.5%) so that the amount and location of economically attractive renewables is determined for various possible future economic conditions. Those are translated into investment cost curves for the investment model by ordering the different potential assessments by increasing generation and fitting a quadratic cost versus generation curve using a least squares fit.

Fig. 3 shows the resulting annualized investment cost and levelized cost of electricity cost function together with the total generation potential. Due to the lack of appropriate building sites, wind power has a much lower potential than PV (10.8 TWh versus 35.6 TWh). Additionally, because of the high costs of labor, equipment, infrastructure, and civil and electrical works in Switzerland, the levelized cost of electricity of wind are much higher than those of PV. Even if the full potential of PV has been used, wind has higher levelized cost.

In addition to this potential assessment, the time-series production from each wind turbine and rooftop PV panel was calculated using the previously established long-term resource potential and the historical 10 min wind speed and solar radiation from MeteoSwiss for 2015. Lastly, these production profiles were aggregated to the nearest high voltage substation.

For renewable energies in the neighboring countries, we rely on a more aggregated approach. The annual electricity generation of wind and solar is provided by European Commission (2016). These annual electricity generation values need to be disaggregated to every hour of a year and to every boundary node of the simulated electricity system. Therefore, the generation numbers are transferred into installed wind and solar capacities (in GW) by incorporating rates of technological improvement for wind and solar generators for future years and average

historic capacity factors. In the next step, the country-wide installed capacities of wind and solar need to be disaggregated to the simulation boundary nodes. This is done in a two-step procedure: First, the relative distribution of wind and solar capacities across Switzerland's neighbors is calculated for the reference year 2015. Second, the additional wind and solar capacities required to reach the planned installed capacities are added to the existing database of generators by assuming a maximum installable generator density of 3 MW/km<sup>2</sup> for wind power and 1 MW/km<sup>2</sup> for solar power<sup>2</sup>. Based on a meso-scale weather simulation with the open-source Weather Research and Forecasting (WRF) model [47], the power production of the renewable generators at hourly resolution is then determined.

For biomass, no detailed potential assessment is performed. The potential used is adopted from the Swiss energy perspectives [48]. The maximum annual generation potential for biomass amount to 5.75 TWh. As Biomass already produces 4.88 TWh in the benchmark year, the potential for new installation in biomass plants amounts to 0.87 TWh.

#### 4.4.2. Reserve dimensioning

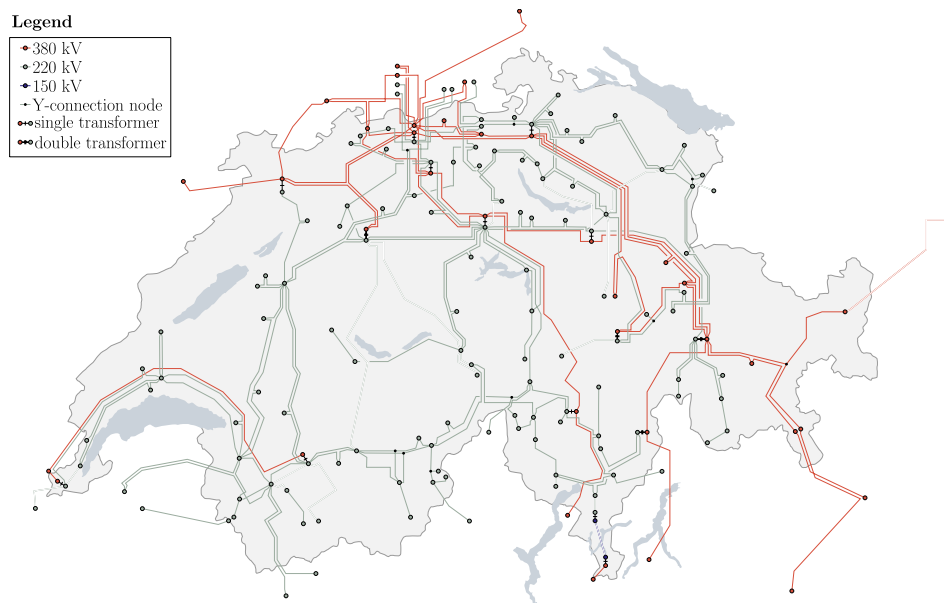
For the **reserve dimensioning** we assume that the amounts currently being procured by Swissgrid (ca. 400 MW of Secondary reserves (upward and downward), 450 MW of Tertiary upward and 390 MW of Tertiary downward reserves [49]) approximately represent the amount of reserves needed to cover for conventional issues (load variability and generator outages). Taking those amounts as the base reserve requirement ( $b_{myt}^0$ ) in reserve market  $m$  in year  $y$  and hour  $t$ , we use a geometric sum with the appropriate contribution to cover wind ( $b_{myt}^w$ ) and PV uncertainties ( $b_{myt}^s$ ) to quantify the total reserve requirement for a given balancing market ( $bal_{myt}$ ):<sup>3</sup>

$$bal_{myt} = \sqrt{(b_{myt}^0)^2 + (b_{myt}^w CAP_{yt}^w)^2 + (b_{myt}^s CAP_{yt}^s)^2}, \quad (13)$$

where  $CAP_{yt}^w$  and  $CAP_{yt}^s$  are installed capacities of wind and PV, respectively. The quantification of the additional reserves needed to cover

<sup>2</sup> With this approach, it is taken into account that the meteorologically best locations for wind and solar generators have mostly already been utilized. This causes new wind and solar generators to be installed in meteorologically sub-optimal locations in future years, which corresponds to the actual development of the power system.

<sup>3</sup> As in equations (6) and (7) balancing demand is differentiated by positive and negative reserve.



**Figure 4.** 2015 transmission grid representation. Also included in the grid model but not shown are aggregate representations of the surrounding countries (i.e., Austria, France, Germany, and Italy).

for the added uncertainty of new wind or PV capacity is based on statistical calculations and methods of forecasting wind and PV generation. To quantify the contributions that those uncertainties would have, the forecast errors are calculated from each of the 10-min time-series data for wind and PV generation in Switzerland based on the renewable data assessment. Using the Swissgrid confidence threshold of 99.9%, the reserve contribution factors can then be calculated from the wind and PV forecast errors.

While the utilization of operating reserves is universally employed among power systems, there is no common methodology for dimensioning the amount of reserves that should be procured. We rely on methodologies presented in Refs. [50–53] and various renewable integration studies [54–57] for our estimates. For wind power, the reserve procedure uses a synthetic forecast created assuming persistence of wind power production from one time period to the next. This type of persistence forecast while computationally simple has been shown to match more complex forecast methodologies for short-term forecast horizons of up to one hour ahead [56]. For solar, the reserve procedure is enhanced to include the impacts of the known daily behavior of the sun. Instead of assuming the persistence of solar power output, the method uses a synthetic forecast created assuming persistence of cloudiness and accounts for the change in the clear sky solar irradiance from one time period to the next.

The forecast errors are quantified for every 10-min period over the year. This process is applied to each wind and PV profile derived from the Swiss renewable potential analysis to establish all contribution factors for these profiles. Once this process is completed, the contribution factors and associated wind and PV capacities for the various RES profiles are used to fit functions that will provide the wind and PV contribution factors for any desired wind or PV installed capacity. However, since the geometric sum is nonlinear, the investment model layer utilizes a simplified version of this process using a least-square fit

to keep the investment model computationally tractable. The dispatch model layer uses the full detailed methodology along with the capacity investments that have been set by the investment modeling layer.

#### 4.4.3. External data input

Beside the above described detailed data, all model layers use the same datasets with respect to thermal power plants, demand levels and profiles, grid data, and underlying cost parameters that are derived from external sources. Again for Switzerland a higher resolution is used than for the neighboring countries.

For the **Swiss thermal power plants** the models include all nuclear power plants and the largest gas, oil and biomass plants. Input data on nuclear power plants is based on information directly provided by the power plant operators, while information on gas, oil and biomass power plants has been acquired from Thomson Reuters Eikon. The model makes use of available information on per power plant capacity, efficiency and technology to derive per power plant cost functions. Fuel costs and CO<sub>2</sub> prices are based on Thomson Reuters Eikon data, while per technology emission factors are taken from [58]. Furthermore, monthly CHP (combined heat and power) profiles have been derived from Eurelectric data [59]. Availability values representing seasonal maintenance and planned outage cycles are based on information from power plant operators for nuclear power plants and are assumed to be similar to German values for other technologies. We assume that Swiss nuclear capacity is gradually phased out: Muehleberg goes offline after 2015, Beznau closes after 2020, Goesgen after 2025, and Leibstadt after 2030. Other changes in Swiss thermal capacities are a direct result of the investment model.

**Swiss electricity demand** levels are exogenous for the models and based on the hourly demand values as provided by Swissgrid [60]. The dataset encompasses both hourly and quarter-hourly demand values on a cantonal level. These cantonal values have then been distributed to all



substations within a Canton. To this end, Voronoi polygons were calculated around each node in the grid and combined with spatial information on population numbers from STATPOP [61] to assign cantonal population shares. Future demand levels are based on the Swiss Energy Perspective [3]. Annual electricity demand is scaled to hourly demand assuming that hourly demand profiles do not change over time. We use the demand profile of the base year 2015 and project it on future annual demand.

In order to represent power flows in Switzerland, a detailed, GIS-based **grid representation** of the Swiss power system including tie-lines between Switzerland and neighboring countries on the 150 (blue), 220 (green) and 380 (red) kV levels has been derived from data provided by Swissgrid for both the current grid configuration (Fig. 4) and the expected 2025 configuration. Extensive effort was applied to ensure consistency between the current and 2025 grid configurations and achieve a sufficient level of detail for the network.

Data on the neighboring **European countries** of Austria, France, Italy and Germany is represented on a more aggregated level than the Swiss data. Assumptions on the future development of generation capacities are based on the reference scenario of the EU energy trends [2]. Power plants are aggregated to power plant blocks per technology and region based on a comprehensive database of 970 hydro power plants and 930 individual thermal power plants [62–64]. The demand representation follows the Swiss approach with fixed hourly profiles scaled according to the projections provided by European Commission (2016) [2]. The demand profile is again based on the reference year 2015. The grid representation includes aggregated line and node data for surrounding countries. Data on tie-lines between neighboring countries are recreated from the ENTSO-E grid map and set to transfer capacity values from ENTSO-E data [65]. For the aggregate depiction of surrounding countries, representative nodes on both the 220 and 380 kV voltage levels have been set up for the smallest regional units bordering Switzerland for which demand data was available (e.g. Bavaria and Baden-Wuerttemberg in Germany). Regions lying behind them have been combined to per country nodes for each voltage level. The per country nodes and nodes in the surrounding regions are connected by near to limitless lines.

For the investment model, both investment and fuel costs are needed to derive an optimal capacity allocation. For the dispatch model only the fuel costs are relevant to decide about optimal short term plant operation. The **cost parameters** are based on the EU-Reference Scenario by the European Commission [2]. Fuel and carbon prices are assumed to be uniform across countries. While prices for lignite are assumed to be more or less constant, hard coal prices show a moderate increase. Gas and Oil prices show a stronger increase from 30 per MWh in 2015 to 45 per MWh in 2050 for Gas and from 32 to 77 per MWh for Oil.  $CO_2$  prices show the strongest increase from 7.5 per ton in 2015 to 88 per ton in 2050. The fuel costs are transferred into a cost function for each technology block by ordering the underlying individual units by their heat efficiency and fitting a quadratic curve over the resulting merit order curve.

We include opportunities for investments into four conventional technologies in Switzerland: new coal fired plants, combined cycle power plants (CCGT), gas turbines, and biomass. The characterization of these generation technologies is based on [66]. For each technology, we choose the cost and generation characteristics in the year 2030 in the New Policy Scenario. We use continuous annuities with an interest rate of 10% and a lifetime of 40 years to derive annualized investment costs. The lifetime of exogenously installed renewable capacity is assumed to be 20 years, i.e., exogenous generation is held constant until 2035 and zero afterwards. In addition to exogenous renewable generation, we allow for investment into new wind and PV capacities in Switzerland based on the investment cost structure presented in Section 4.4.1. As those cost assumptions are not consistent with the fuel and carbon price assumptions provided by [2] and, therefore, the underlying the calibration of conventional generation cost, we scale our PV

cost estimates to match the average values provided in the EU-Reference Scenario. We then use the same scaling factor to scale the leveled cost of wind power. As a consequence, renewable investment cost calibration is, on the one hand, consistent with the assumption on conventional power cost. On the other, we preserve the relative cost of wind and PV based on the analysis of the Swiss case.

## 5. A Swiss case study

Following, we will apply the above described model framework to carry out an assessment of the potential future development of the Swiss electricity system. The two future development scenarios are based on the reference scenario of the EU energy trends [2] for the neighboring countries as described in the previous section. Thus, the model runs represent a setting in which only the Swiss policy is altered whereas European developments are maintained on a reference pathway. Comparing the two scenarios will provide a first estimation of the scope of policy intervention needed to obtain the desired extension of renewable generation in Switzerland and the resulting system effects.

### 5.1. Calibration to 2015

The dispatch model, as the central element to capture the electricity market dynamics, is calibrated on observed price, generation and trade patterns for the year 2015 from ENTSO-E data [62]. To this end, calibration parameters were applied to power plant availabilities and cost assumptions (specifically the intercept and slope of the quadratic cost functions). The same calibration factors resulting from the base year calibration of the dispatch model are applied to the scenario study (see next Section) and the investment model.

With regards to electricity prices, the model closely matches Swiss yearly average prices with a deviation of less than 5%. German, French and Italian prices are also well matched with deviations of less than 3%. Larger deviations can be found for Austria (around 12%). These larger deviations are likely to be caused by ignoring imports and exports to other surrounding countries which are outside of the model scope. The hourly price patterns (see Figure A1 in the Appendix) show an overall good fit of model prices with real 2015 price dynamics. However, due to the deterministic structure of the model and due to the fact that we abstract from more detailed features of conventional power plants such as start-up costs or ramping restrictions, price peaks are not as pronounced in the model results as in reality. This can be seen especially towards the end of the year, where upward price peaks in Switzerland, Germany, France and Italy cannot be properly replicated. Furthermore, the model is unable to replicate the observed negative prices.

Similarly, the matching with real generation is rather accurate for most technologies (see Figure A2 in the Appendix). Both baseload units like nuclear and lignite but also peak generation from gas and oil are well replicated. Only Italy shows a trend towards slight overproduction across all thermal generation technologies. In addition, coal and gas in Austria and coal in Germany show some overproduction<sup>4</sup>.

Swiss seasonal production patterns are well aligned to the original patterns (Fig. 5) also resulting in a similar hydro storage profile (see Figure A2 in the Appendix). However, the deterministic nature of the dispatch model results in lower storage levels in spring, where the model fully utilizes available water, and higher levels in autumn. This in turn also leads to a prolonged net export position of the modeled system in the summer and fall months. Comparing the overall import and export patterns the model matches the general trends but shows differences when comparing the absolute levels: while French imports are matching fairly well (13.4 vs 14 TWh), Austrian and German

<sup>4</sup> Note that biomass and gas generation in Switzerland cannot be compared to real values as these technologies are missing from ENTSO-E statistics for the base year.

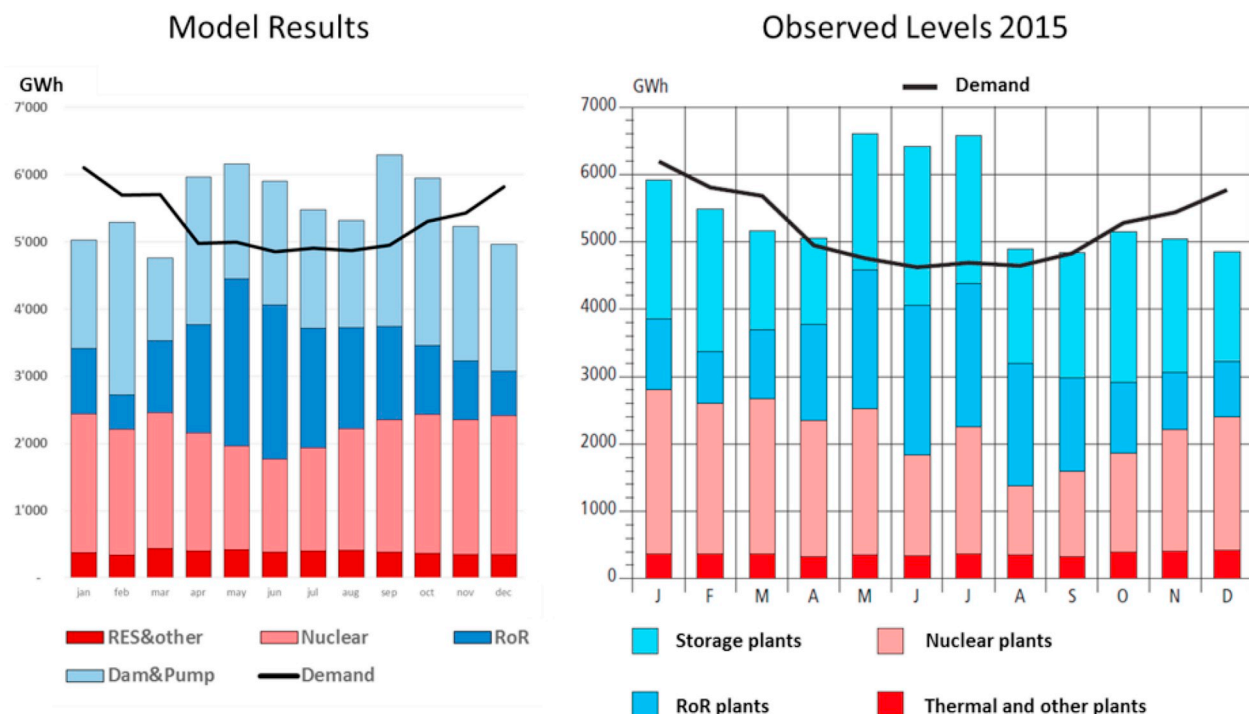


Fig. 5. Comparison of modeled Swiss monthly dispatch with observed levels (Source [67]: Table 10).

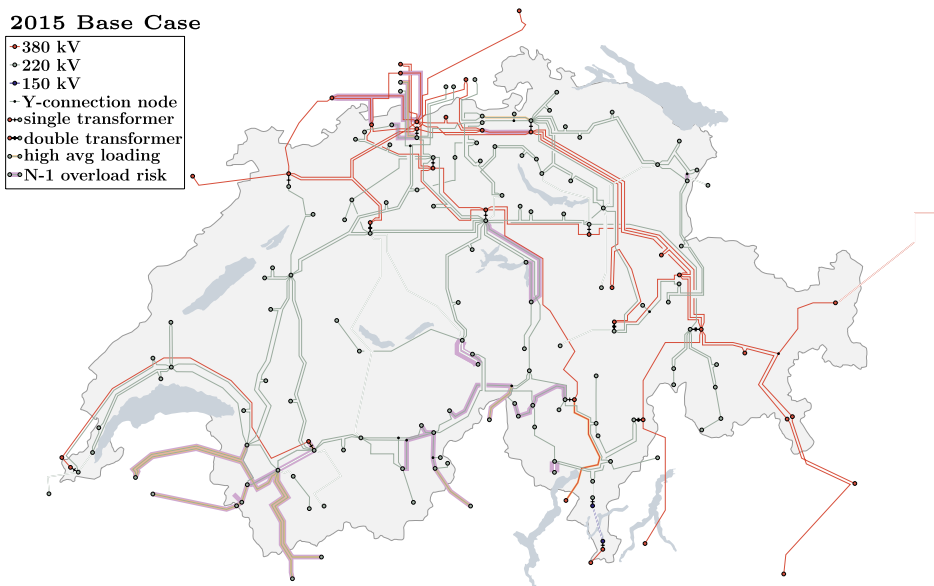


Fig. 6. Transmission network assessment of calibrated 2015 dispatch result.

imports (8.7 vs 4.2 TWh for Austria and 5.7 vs 4.5 TWh for Germany) and exports to Italy are overstated (30.5 vs 23.6 TWh). In total, this leads to a net export position of Switzerland that is larger than observed values (2.7 TWh vs. 1.0 TWh). In combination with the general overproduction in Italy in our model, it is likely that the available input data might overestimate Italian demand or we might underestimate RES-

infeed for Italy.

Using the hourly dispatch results from this 2015 calibration, the impacts on the AC transmission network reflect many of the same areas that are currently prone to congestion as indicated in Swissgrid's Strategic Network 2025 planning document [68]. In general, we find that the lines connecting Switzerland to one of its neighboring countries

tend to be the most heavily loaded (highlighted orange in Fig. 6). These connections represent critical bottlenecks limiting the import or export of power across the Swiss border. While our network simulations indicate that the majority of lines and transformers in Switzerland are rarely reaching their power flow limits, the ones that do tend to be near the Swiss border. Additionally, we find that many of these same lines along with other cross-border and internal Swiss lines tend to be at the highest risk of overloading in response to a contingency (highlighted in purple in Fig. 6). Swissgrid's analysis is able to identify more internal Swiss lines as problematic based on their more detailed grid knowledge. In Figure A.4 (in the Appendix), box plots are used to further illustrate the range of line loading percentages across all hours for each of the Swiss cross-border lines. Each boxplot represents one line and shows the median (red horizontal line), 25th and 75th percentiles (blue box), non-outlier range (dashed whiskers), and outliers (red plus signs). The first eleven boxes represent all line connections between Switzerland and Germany, followed by eleven lines that connect Switzerland to France, then ten lines connecting Switzerland to Italy and finally four lines connecting Switzerland to Austria. The green horizontal line is added for reference at 80% loading, which was enforced as an upper limit during the dispatch model simulation. This image shows several connections to France that occasionally are heavily loaded, but in particular highlights the one German and three Italian connections that are consistently heavily loaded (median values of 70% or more).

Overall the results of the calibration process show that the dispatch and security model layers are capable of reproducing existing market dynamics.

## 5.2. Is the Swiss Energy Strategy 2050 achievable

Like most European countries, Switzerland also aims at transforming its electricity supply. Following the nuclear accident at Fukushima, Switzerland's original plan to replace its aging nuclear plants with new units and keep a nuclear and hydro dominated supply structure was replaced by a comprehensive energy policy package termed the Energy Strategy 2050. Its main objectives are the phase-out of nuclear power, increase of new renewable energy provision (11.4 TWh in 2035, ca. 20%), and an ambitious energy consumption reduction target (–43% per capita consumption compared to 2000 by 2035). For the electricity system this opens up two main questions:

1. How will the system cope when the nuclear generation (ca. 40% share) is phased out?
2. How can the envisioned increase in new renewable generation be achieved?

Following the framing of the Energy Strategy 2050 we define two scenarios:

- First, a **no-intervention case** based on the current energy-only electricity market structure as a baseline to identify how the projected phase-out of Swiss nuclear power plants impacts the Swiss system.
- Second, a **renewable support case** imposing quantity targets in line with the objectives of the Swiss Energy Strategy 2050 [3] (i.e., 11.4 TWh in 2035 and 18.4 TWh in 2050). For the years in between we linearly interpolate these targets.

A fully detailed description of the Swiss scenario results is provided for further transparency in the underlying project working paper [69].

Finally, we contrast our findings to the scenario assessment of the Energy Perspectives 2050 [3] underlying the Swiss Energy Strategy 2050 as well as related Swiss electricity assessments to highlight the additional insights obtainable from the coupled model framework.

### 5.2.1. Future development

Turning from the current system conditions to potential future developments, we first use the investment model layer to identify how the Swiss electricity supply could change under the two different policy frameworks.

If no support policies nor additional market elements are implemented (no-intervention case), Switzerland will mostly rely on imports to replace its phased out nuclear reactors (Fig. 7, left panel). Besides a minor increase in biomass capacity, the only significant occurring investments are in PV generation from 2040 onwards to a maximum of ca. 5 TWh in 2050. However, those levels fall short from the desired increase postulated in the Swiss Energy Strategy 2050. If those are directly implemented via a quota mechanism (renewable support case), investments are consequently altered with the majority coming from PV generation supplemented by relatively minor wind additions (Fig. 7, right panel). Coupled with the ca. 6 TWh of biomass and waste-fired generation this amounts to the targeted 18.4 TWh, compensating for a significant share of today's 20 to 25 TWh of nuclear production.

The detailed renewable potential assessment allows transferring those aggregated numbers into detailed regional capacity and generation volumes (Fig. 8, left panel). In 2050 19 GW of PV and 0.5 GW of wind are installed in the renewable support scenario, generating 11.6 TWh and 0.7 TWh over the year, respectively. The majority of those investments occur in the south-western half of Switzerland with noticeably large concentrations of PV around Geneva, Lausanne, and Bern (due to the higher solar potential on the available roof-top space in those urban areas compared to north-east Switzerland). This information is crucial for assessing potential network related feedback effects.

The investment model also allows deriving the needed monetary incentive structures to realize those investments. Fig. 8 (right panel) shows the average income of solar power (columns) by income category. Under a renewable premium, renewable producers receive the market price as well as the premium. In 2020, the renewable target is already fulfilled by production from existing biomass plants and wind and PV generation facilities. Therefore, the premium is equal to zero. Afterwards, the premium increases and forms an important part of the needed income for PV generators. The premium is within the range of 20–40 €/MWh which translates into a final tariff surcharge of ca. 9 €/MWh in 2050 (roughly 5% of today's end-user tariff).

Transferring the capacities from the investment model to the dispatch layer, we are able to compare the seasonal generation structures across several years. Fig. 9 illustrates the generation for the years 2020, 2035 and 2050 for both the no-intervention and renewable support cases. In case of no further policy or market interventions, the export during summer disappears and is replaced by a general net-importing position. Swiss net-imports in the no-intervention case amount to around 1.8 TWh in 2025 and around 15.6 TWh in 2050. Introducing a renewable target does alter the seasonal import and export structure gradually back towards today's pattern after the nuclear phase out. The increased PV and wind capacities lead to a net-exporting position in summer and imports during winter. However, the yearly net-import position is still above today's levels with about 9.2 TWh in 2050 (compared to 1 TWh in 2015). Furthermore, the renewable generation only marginally affects the dispatch seasonality of hydropower; in other words, only a small fraction of those PV surpluses are transferred into winter generation via shifted hydro production.

Transferring the dispatch results to the security model allows to further investigate how the altered generation and import and export patterns impact the Swiss transmission network. One would expect the stronger reliance on imports to result in noticeable increases of line loadings, especially across or near the Swiss borders. However, the results actually indicate that the loading of the Swiss network gets progressively lower from 2020 to 2035 to 2050 (Fig. 10). While part of the reason for this unexpected result are network expansions planned by Swissgrid, two other key changes influence this result. First, between 2020 and 2035 the increase in net

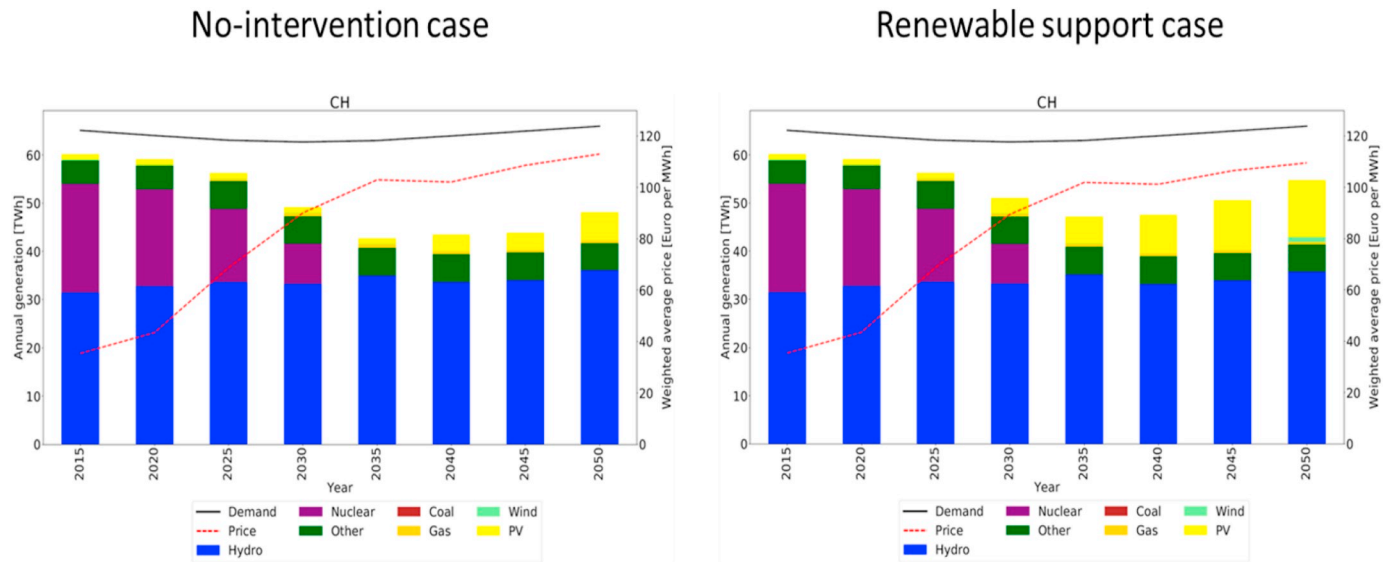
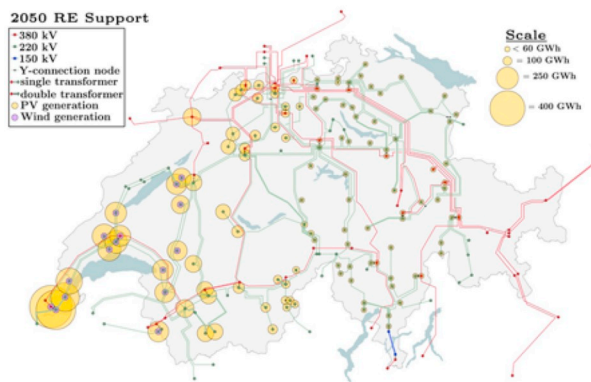
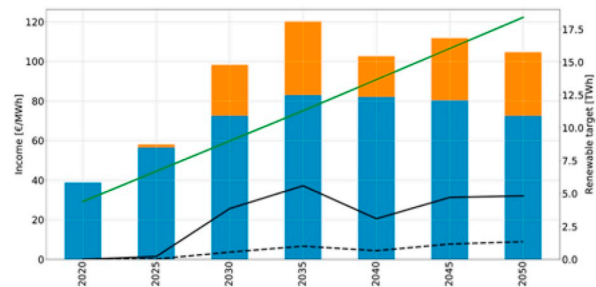


Fig. 7. Swiss generation development until 2050. The bars represent the annual Swiss generation in TWh by technology (left axis), the black line represents the annual Swiss demand in TWh (left axis), and the red line represents the average annual Swiss market clearing price of electricity in Euro/MWh (right axis).

### Locations of RE generation (2050 Renewable Support scenario)



### Income and RE Support Premium (Renewable Support scenario)



Notes: Mean income of solar producers by year (left axis €/MWh) differentiated in market (blue) and premium (orange); renewable premium (black line) and final demand surcharge (dotted black line; both left axis €/MWh); renewable target in TWh (green line, right axis).

Fig. 8. Renewable deployment.

imports is actually due to a significant reduction in exports and a somewhat larger increase in imports, which combine to yield a large shift toward being a net importer. Beyond 2035, a different change takes place characterized by increased generation in Italy and subsequent large reductions in trade going towards Italy. Both of these changes yield higher net annual imports for Switzerland while also reducing total line flows crossing the Swiss border. So, the shift of Switzerland to a more import dependent country does not negatively impact the network reliability.

Also, one could assume that the additional PV generation in the Renewable Support scenario causes additional network congestion and reliability risks. The model results show increased RES curtailments in 2050 (8.9 GWh, up from 2.2 GWh in the No Policy case), which indicates that the network cannot accept some of the RES injections; but this amount is less than 0.01% of RES generation. However, comparing the results of the 2050 Renewable Support and 2050 No Policy cases, we find nearly identical line loading results. As shown in Fig. 8 above, PV and wind generation are distributed across Switzerland with small injections in many locations and

large injections in a few western urban locations. In all cases, the renewable energy is mostly serving local load and not being transported on the transmission system actually reducing power flows.

The N-1 contingency results support these line loading results by also showing a significant decrease in contingency/overloading occurrences from 2020 to 2050 (Fig. 10). Additionally, several combinations of contingency/overload occur in almost all hours of the 2020 scenarios while at worst in 5500 h of the 2050 scenarios<sup>5</sup>. Adding further PV and wind generation in the renewable target scenario does not alter this general picture. The primary areas of congestion are still the cross-

<sup>5</sup> While these amounts of contingency/overloading occurrences might seem high, the dispatch model uses a generic 80% line limit which provides limited constraints for the no-contingency power flows. More specific limits that target certain highly loaded or parallel lines would be used in practice based on past experience with the network flows.

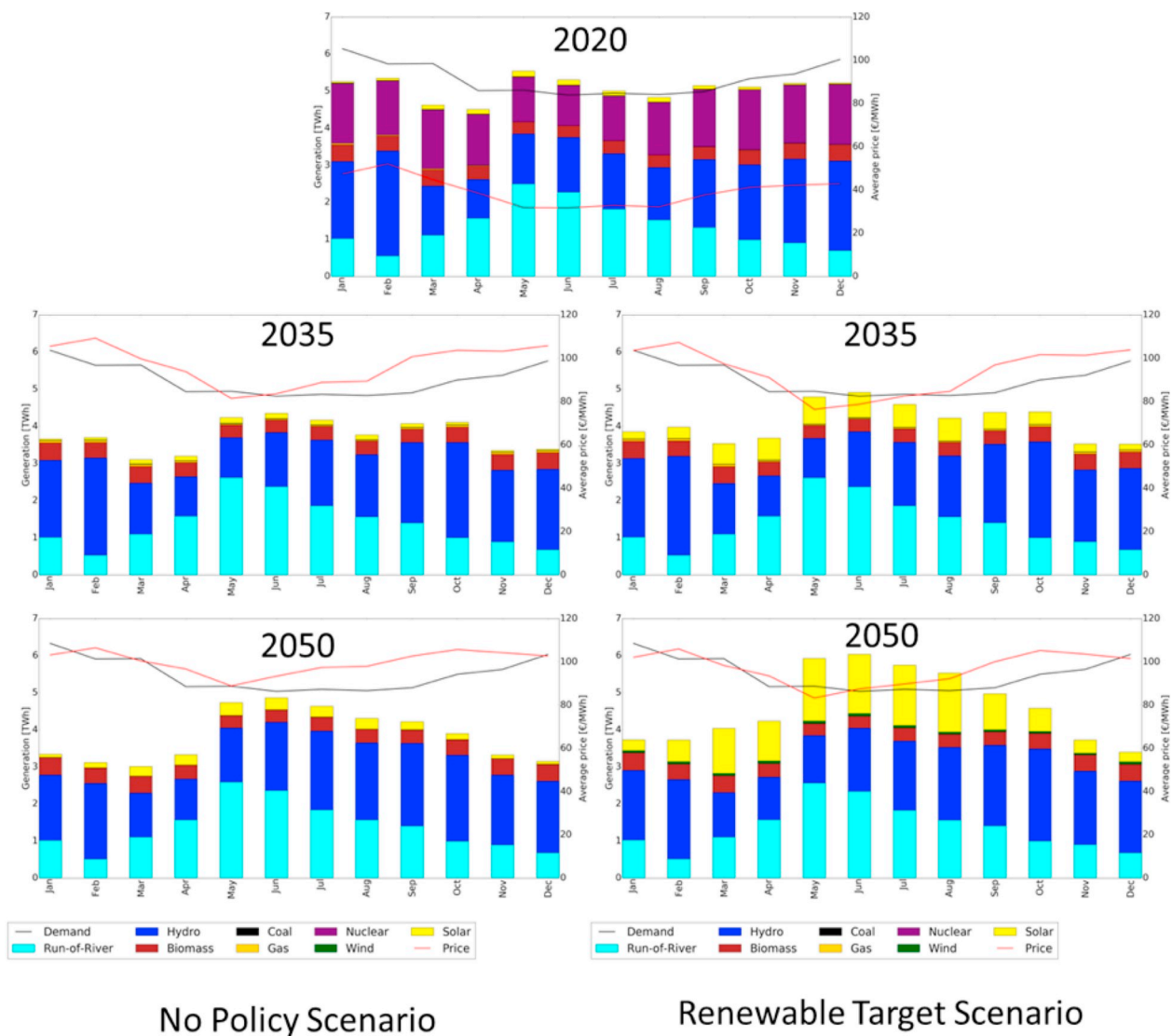


Fig. 9. Dispatch and prices in Switzerland for the years 2025 and 2050.

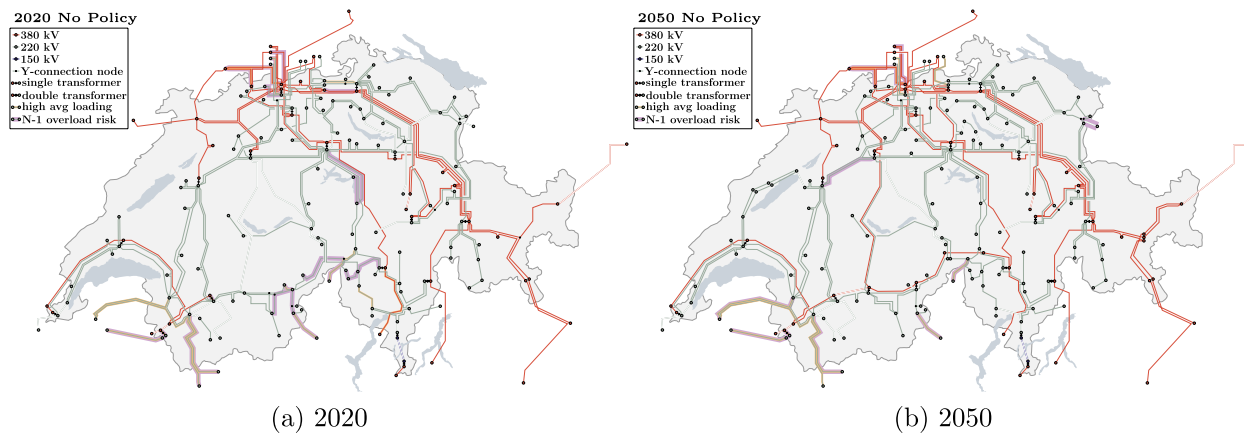


Fig. 10. Heavily loaded lines and contingency risks for the no-intervention case.

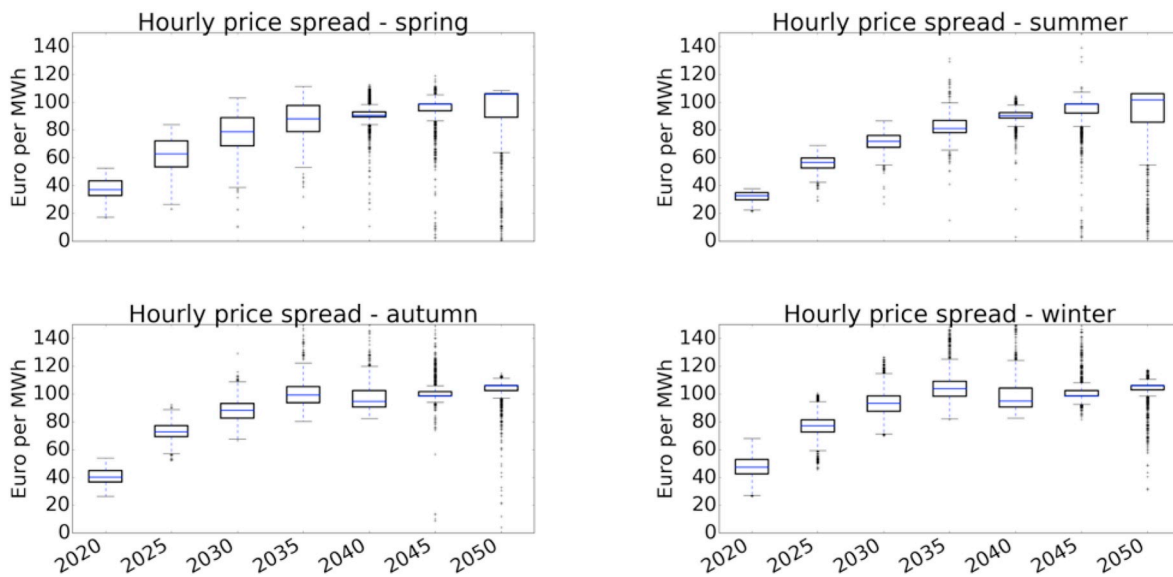


Fig. 11. Seasonal price variability for renewable target scenario.

border lines. The internal Swiss network is generally not heavily loaded in any of the cases, so it is able to cope with the added RES injections that are dispersed across Switzerland without creating significant new bottlenecks in the network.

Overall, the general system dynamics are in line with what one would expect to see based on the underlying data structure and existing Swiss system conditions: given the favorable import situation for Switzerland (i.e. large cross-border capacities and large neighboring electricity systems) and the overall large network capacity in relation to indigenous demand, a strong reliance on imports is a natural consequence.

As the envisioned renewable targets can only be achieved via a policy intervention, the model framework allows us to evaluate the accompanying consequences in more detail. Compared to the no-intervention case, the overall Swiss price level is slightly lower with a renewable target in place (see Figure A3 in the Appendix); a direct result of the merit order effect for the additional capacities. However, the lower wholesale prices are offset by the quota price for green certificates needed to initiate the additional investments (see Fig. 11, right panel). Consequently, end-user charges are going to increase with a quota in place.<sup>6</sup> Overall, the Swiss market price dynamic is mostly influenced by European market conditions which in turn are shaped by the underlying fuel price trends and increasing shares of renewable generation. While the former leads to a general price increase over time, the latter leads to more pronounced low price valleys, especially in spring and summer due to high PV shares (see Fig. 11).

The additional renewable injection of the RES Quota case increases the amount of curtailed RES infeed (i.e. in case of insufficient local network capacity renewable injection is reduced). However, the absolute levels are minor: about 60 MWh of additional curtailment in 2050. In total, about 1% of total RES infeed needs to be curtailed in 2050. Thus, the projected locations of new PV and wind generators are in general well suited to ensure a high usage share. With regards to security of supply, no loss of load events occur in the 2025 system. For 2050, few loss of load events occur, amounting to 912 MWh (0.0014% of total load) under the no-intervention case and 295 MWh (0.0004% of

total load) under the renewable support case. These small amounts of loss of load could be easily mitigated by additional DSM measures or battery storages.

The increased RES infeed has only minor impacts on network security. The areas prone to congestion in the 2050 renewable support case are unchanged compared to those in Fig. 10. Figures A6 to A.8 (see the Appendix) provide a comparison of the box plots for line loadings of the 2015 Base case, 2050 No Policy case and 2050 RES quota case for the 30 most heavily loaded internal Swiss lines in each case. The resulting changes in internal Swiss line loadings for the 2050 RES Quota case are impacted more by the increased imports and transit flows and less by the additional local RES generation. So, the overall network and security assessments show no significant challenges associated with a faster and stronger renewable increase in Switzerland. The main political concerns, therefore, should be related to the increased consumer costs in case of a quota mechanism and the high level of imports in case of no additional intervention.

### 5.2.2. Comparison with Swiss Energy Perspectives

As indicated above, the Swiss government decided to revise its energy policy following the nuclear accident in Fukushima. The underlying targets (nuclear phase-out, increased utilization of renewable energies, reduction of energy consumption) have been summarized as ‘Swiss Energy Strategy 2050’ and are the guideline for the ongoing energy policy in Switzerland. Within the development process of the Energy Strategy, the model-based scenario assessments of the updated Swiss Energy Perspectives [3] providing a comprehensive outlet for potential pathways of the Swiss energy demand and supply were central. The perspectives provide three scenarios: first, a business-as-usual setting continuing the policies in place; second, a targeted scenario aimed to identify the needed policies to achieve a significant reduction of per capita emissions termed ‘New Energy Policy’; and third, an explorative scenario covering a set of likely ‘Policy Measures’.

The perspectives are based on an energy system model including all sectors based on a detailed database for energy demand structures and provision technologies. With respect to the electricity sector, the underlying model identifies the available generation capacities (i.e. existing Swiss hydro, nuclear, fossil and renewable facilities accounting for their lifetime) and demand in Switzerland to derive the need for additional investments. Which technologies are used for those investments is then pre-defined via three supply cases: ‘Only fossil-fueled plants’, ‘Fossil fueled plants and renewable’, and ‘Renewables and

<sup>6</sup> Whether Switzerland is going to implement a green-certificate system is still not decided. However, even under a premium or feed-in system, the corresponding wholesale price reaction and surcharge to refinance renewable subsidy will be equivalent.

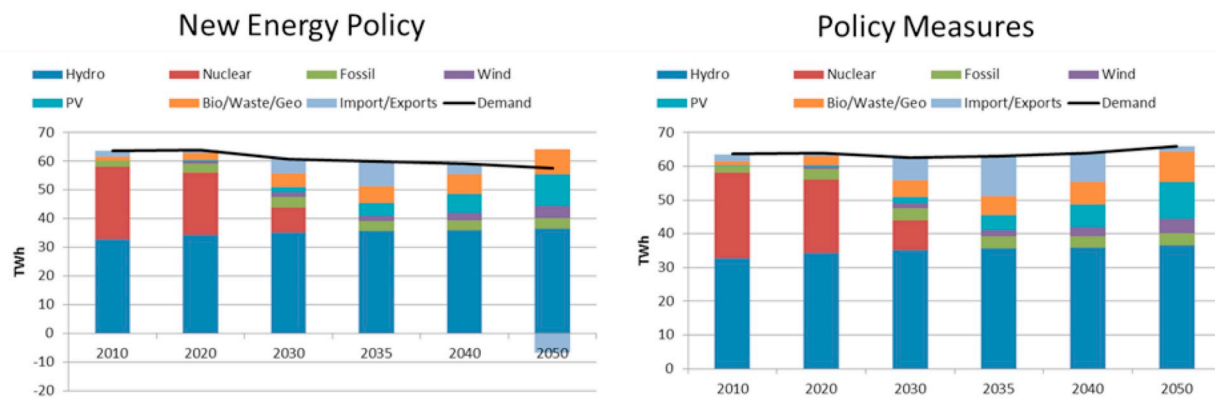


Fig. 12. Swiss Energy Perspectives, supply cases 'Renewables and Imports (Source: Prognos [3]).

imports'. The electricity model approach does not include a network representation and also does not cover dispatch decisions in neighboring countries.

Fig. 12 shows the development of the systems for the cases that are closest to the scenarios presented in the previous section. Given the difference in underlying assumptions and model structures between our framework and the perspectives, it is not surprising that the derived pathways greatly differ. Based on the endogenous investment logic of our approach and contrary to the pre-defined investment structure of the perspectives, we observe a higher level of imports in our assessments. Regarding renewable investments our assessment in the renewable support case shows a similar level of investment in solar (ca. 11 TWh in 2050) but lower wind (ca. 1 vs. 4 TWh) and biofuel/waste-based investments (ca. 6 vs. 9 TWh).

While those differences are a natural result of different underlying assumptions and model structures, the main challenge that an integrated framework allows us to address is the consistency across different dimensions. The Energy Perspectives form the basis of different follow-up studies addressing specific issues of the Swiss electricity system (e.g. the system adequacy studies by the SFOE [70]) or as input and comparison for energy scenario studies (i.e. see Braunreiter et al., 2018 [71]). However, these follow-up and complementary assessments naturally lack consistency in terms of the underlying dataset. Especially with respect to the placement of renewable capacities as well as demand dynamics this inconsistency could easily lead to misleading conclusions.

## 6. Conclusions

The electricity system is changing rapidly in Europe at the moment and the resulting challenges of these changes are becoming more and more evident. This transition calls for changes in the regulatory framework as well as the relevant market design. However, to assess these needed changes, adapted or newly developed tools are needed to analyze future scenarios. Only then can informed decisions be made by involved politicians, administration and regulatory authorities. The proposed methods in this paper can act as a basis for such scenario analyses.

Within this paper we propose a model framework suited for addressing the challenges electricity systems with a high share of weather dependent (intermittent) renewable generation face or are about to face. It combines the needed high temporal and geographical resolution for renewable evaluations with detailed modeling of electricity dispatch, balancing, network and investment aspects. Applying the framework to a Swiss case study of a no policy setting and a renewable support case provide important insights for the Swiss energy transition.

The results of the data and model layers highlight the different aspects of the transition process: the renewable assessment shows that solar energy will dominate the renewable mix thanks to a significant cost advantage; the reserve assessment shows that the projected renewable increases do not lead to large additional balancing requirements; the investment layer highlights that rather modest price mark-ups would be sufficient for reaching the imposed renewable targets; the dispatch layer shows rather modest alterations of the seasonal dynamic; and the network layer highlights that thanks to the existing and projected transmission capacities no significant network contingencies or loss of load events occur even with high shares of import or renewable generation.

The advantage of a coupled framework structure is the consistency within the evaluation process of the most pressing aspects of energy transitions. Neglecting specific dimensions can easily lead to an over-estimation of specific system developments, for example a too optimistic extension of renewable capacities, or on the other hand, over-pessimistic assessments regarding system stress due to high shares of renewable energy sources. Our framework has the capability to evaluate additional limitations in future follow-up assessments: e.g., the analysis of network congestion under even higher amounts of renewable power and the identification of meaningful network extension investments; as well as to evaluate other unique scenarios such as electrification of transport<sup>7</sup> or other power sector evolutions. Therefore, the proposed framework is able to deliver a consistent evaluation of future energy pathways coping with varying temporal and spatial dimensions from minutes to years and network nodes to countries.

While the framework as presented in this paper is implemented within a joint modeling effort, it would already be beneficial for relevant policy scenarios if their datasets would be publicly provided following the linkage structure indicated in Fig. 1. This has for example already been implemented for the underlying dataset of the Swiss system adequacy assessment. A similar open data as well as an open modeling approach embedded in a linked framework would enable complementary assessments while maintaining a high degree of consistency.

## Acknowledgements

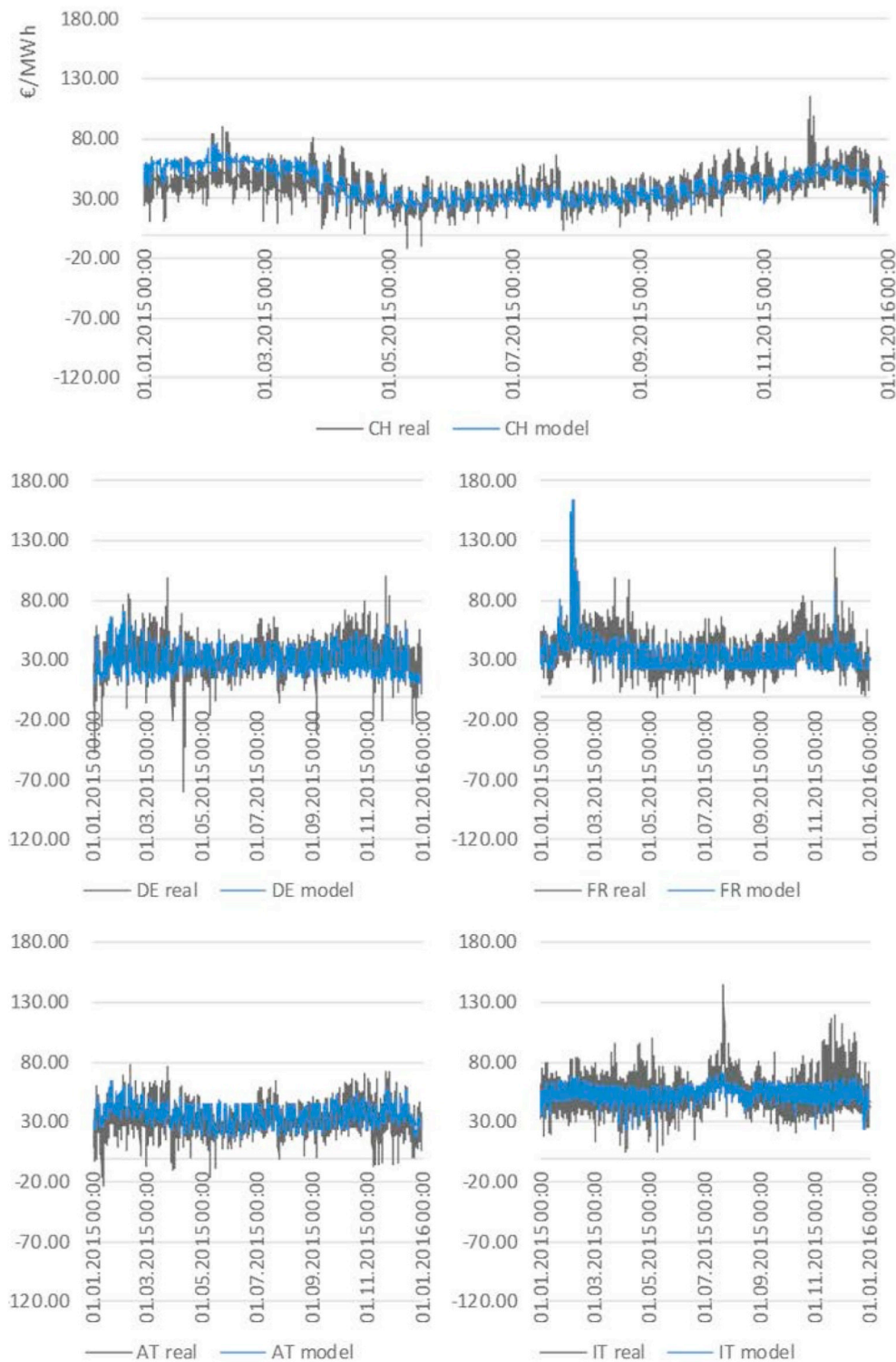
Funding for this work was graciously provided by the Swiss National Science Foundation through their National Research

<sup>7</sup> It is important to note that, the scenarios underlying this paper exclude the electrification of other sectors. While this can be seen as a limitation to the results shown here, the model framework itself is well suited to address such issues (e.g. by incorporating changes in load assumptions).

Programme ‘Energy Turnaround’. Data for the high voltage transmission network was provided by Swissgrid. The authors would also like to acknowledge the contributions others have provided for this work,

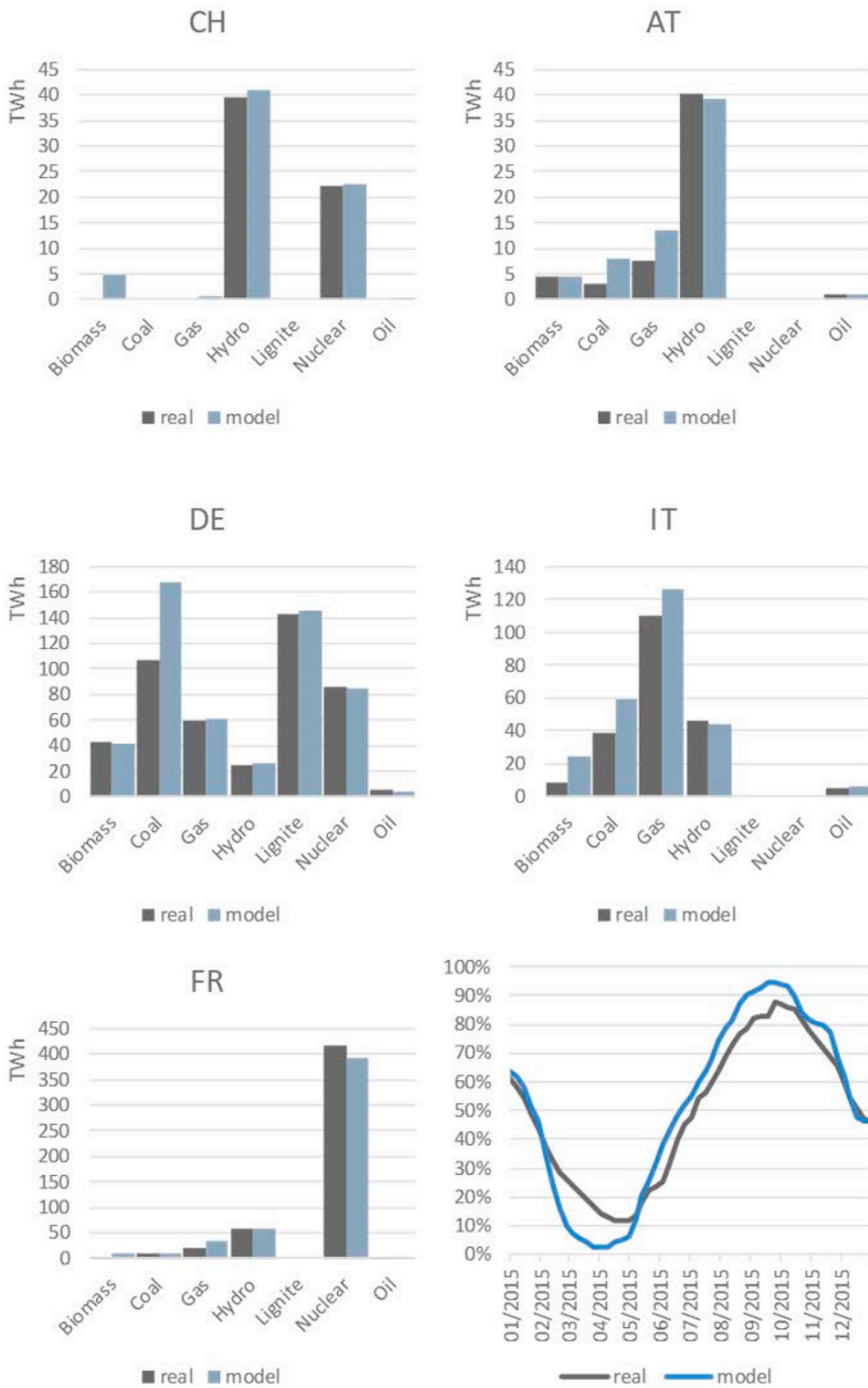
including: Christian Schaffner, Turhan Demiray, Sebastian Rausch, Stefano Grassi, Fabio Veronesi, Carla Manuela Tavares Mendes, Martin Raubal, and Rene Buffat.

**Appendix A. Additional plots**

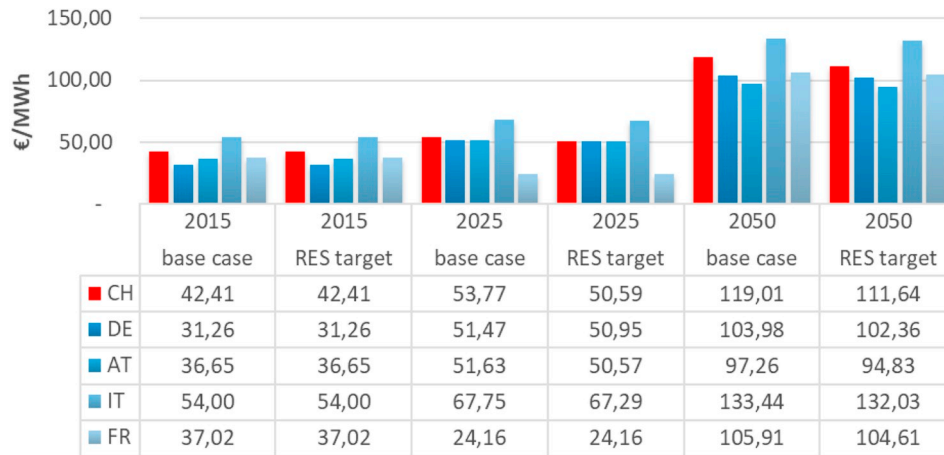


Hourly electricity prices [€/MWh].

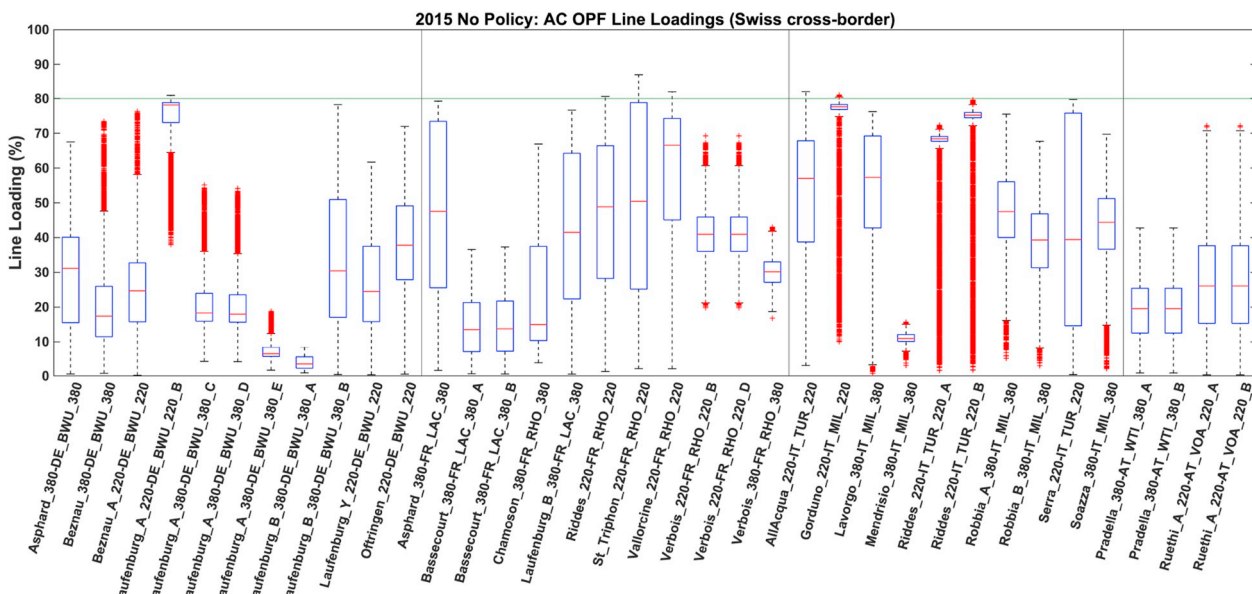




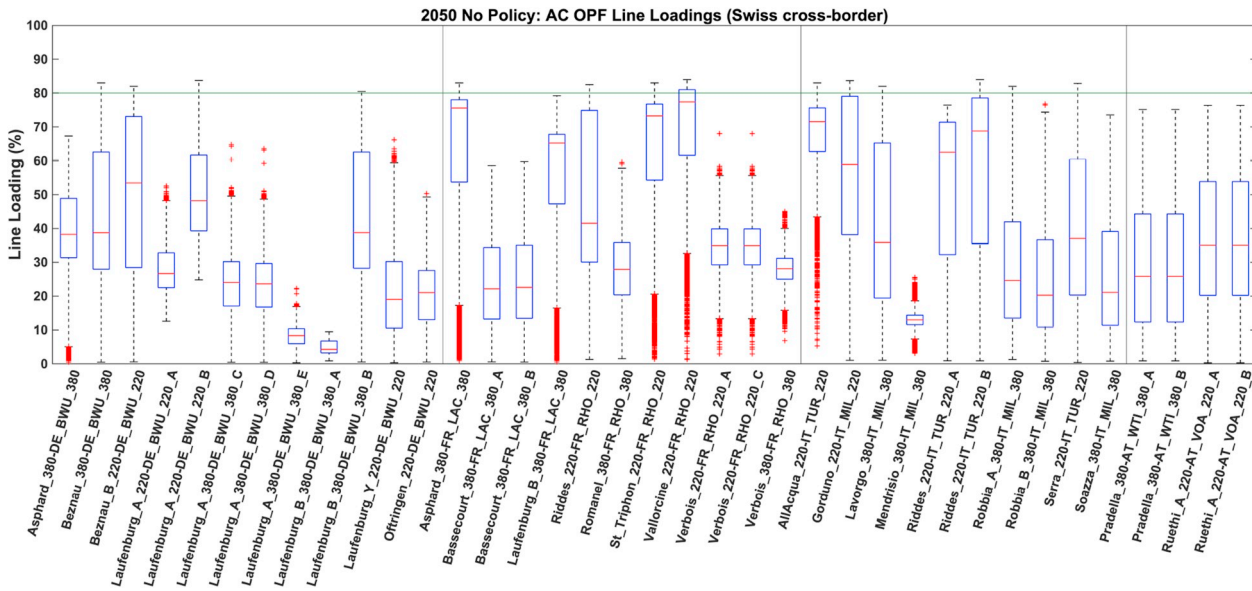
Yearly generation and storage level.



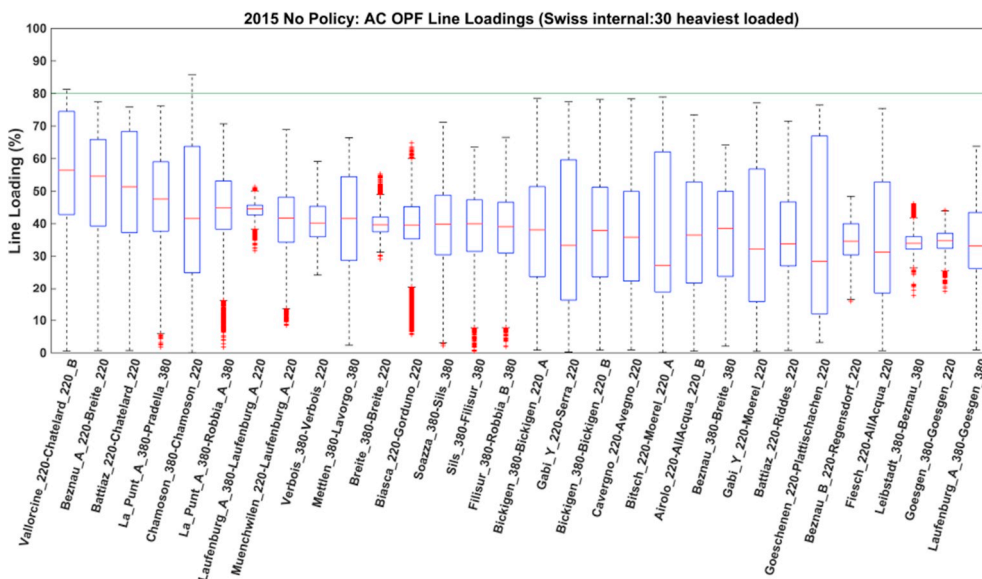
Average wholesale electricity prices per year and scenario [€/MWh].



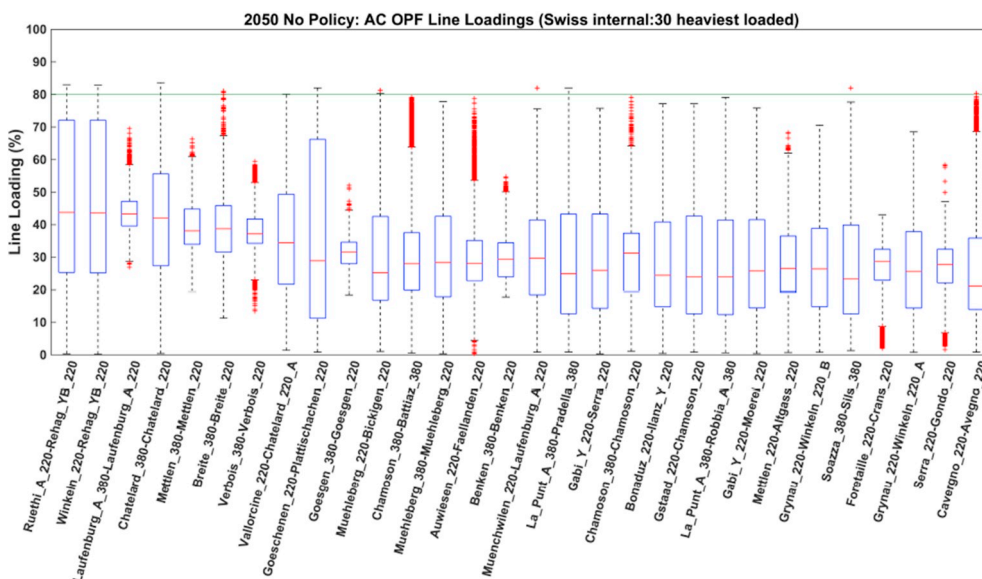
Boxplot of line loading percentages for each Swiss cross-border line (each box represents 8760 h) in Scenario 2015 No Policy.



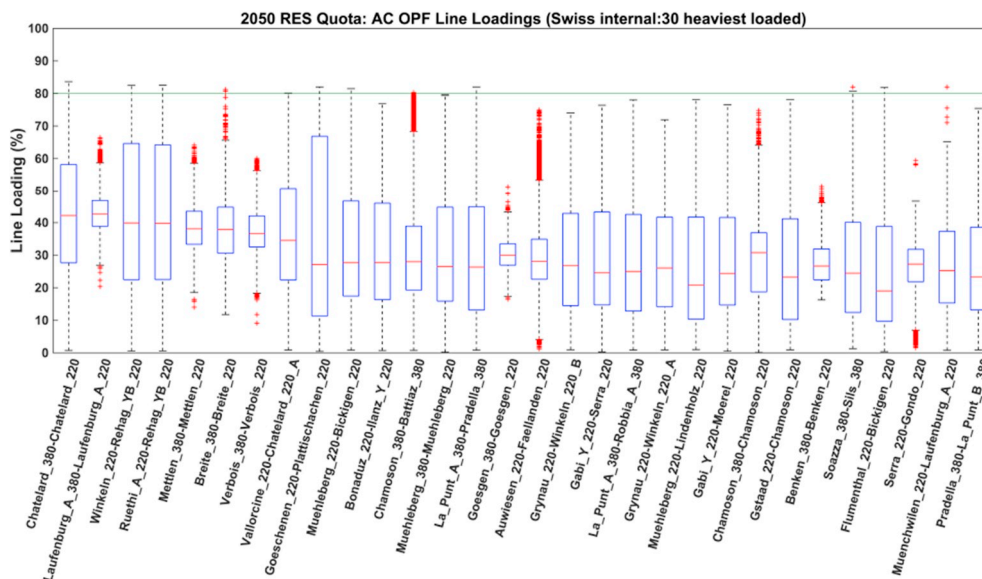
Boxplot of line loading percentages for each Swiss cross-border line (each box represents 8760 h) in Scenario 2050 No Policy.



Boxplot of line loading percentages for the 30 highest loaded internal Swiss lines (each box represents 8760 h) in Scenario 2015 No Policy.



Boxplot of line loading percentages for the 30 highest loaded internal Swiss lines (each box represents 8760 h) in Scenario 2050 No Policy.



Boxplot of line loading percentages for the 30 highest loaded internal Swiss lines (each box represents 8760 h) in Scenario 2050 RES Quota.

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