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The Future Electricity Market Model - FEM: Model Description

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Abstract

The Future Electricity Market Model (FEM) is a comprehensive technoeconomic model designed to simulate the investment, dispatch, and trade dynamics within the power systems of Switzerland and Europe. FEM operates as a partial equilibrium model of the wholesale electricity market, minimizing total system costs while adhering to a wide range of technical constraints. It provides projections of capacity mix, hourly prices, generation profiles, storage dispatch, flexible consumption, and cross-border electricity trading across different market areas. The model is formulated as a quadratic programming problem, implemented in Python, and solved using the Gurobi optimizer. With an hourly resolution over a year and a specific focus on the Swiss power system, FEM allows investment decisions solely within Switzerland, while the rest of Europe follows predefined development scenarios. Key features include the modeling of various renewable and conventional energy technologies, integration of storage systems, and incorporation of detailed electricity demand and trade constraints. In order to model the hydro power system more realistically, the model follows a hydro calendar year, i.e., the model starts at the beginning of October. Despite its deterministic approach, assuming perfect foresight, which may introduce an optimism bias, FEM serves as a powerful tool for analyzing the future dynamics of electricity markets under various scenarios.

1 Overview

Objective function and decision variables. For a given hour-by-hour electricity demand and renewable infeed profile, FEM minimizes total system cost, i.e., the sum of annualized capital costs, fuel costs, and other fixed and variable costs of generation, and storage assets. Given that the model is focused on Switzerland, the model allows investments only in Switzerland. Investment and generation are jointly optimized for one representative year. Decision variables comprise the investments in different generation and storage capacities, dispatch of power plants including storage technologies, and electricity trade between regions, load shedding, and curtailment of renewable sources. Core constraints constitute the energy balance, capacity limitations, energy storage limitations, and start/end conditions for the hydro system.

Technologies. The model covers new renewable energy sources comprising photovoltaics (PV), onshore wind, and offshore wind. The hourly generation profile is limited by weather-dependent and exogenously defined availability factors. The generation can be curtailed without a cost. In addition, the model includes the following conventional thermal technologies: hard coal, lignite, nuclear, combined cycle gas turbines – CCGT, simple cycle gas turbines – SCGT, bioenergy-fired power plants (i.e., biomass), gas-fired CCGT with CCS, CCGT and SCGT plants using green methane as fuel, liquid-fuel (oil). Additionally, the model incorporates various hydropower technologies, including run-of-river, dam plants, closed-loop pumped storage, and open-loop pumped storage systems. The model includes other storage options such as lithium-ion batteries and hydrogen-based storage systems that is modeled as a power-to-hydrogen-to-power closed loop.

Investment decisions. FEM allows for investment only in Switzerland while generation capacities on the European side are fixed to values defined by corresponding scenarios chosen for the Europe. New investments must recover their annualized capital costs from profits in the simulated year. The hydro power capacities are also fixed to predefined scenarios. The model takes into account the pre-existing capacities available in Switzerland and planned retirement of power plants, e.g., nuclear power plants in Switzerland. Since the models runs for one representative year, investment costs are included

as annualized fixed costs. Eventually, hourly generations by power plants are constrained relative to the available capacity.

Electricity demand. Demand is taken as an exogenous input and assumed to be perfectly price inelastic but for very high prices, in which case load is shed. In addition, the model includes electrolyzer plants with a given minimum annual electricity consumption constraint (hydrogen generation). Electricity consumption of electrolyzer plants can be shifted within a year, constrained by an hourly capacity limit.

Trade. Cross-border electricity trade is endogenous and limited by net transfer capacities (NTCs). Within regions, transmission capacity is assumed to be non-binding.

Geographical scope. The model can be applied to different geographical scopes. Data is readily available for Switzerland (per the seven grossregionen) and roughly speaking its neighbours and the neighbours of the Swiss neighbours. More precisely, the model includes Switzerland, Italy, Germany, France, Austria, Denmark, Belgium, the Czech Republic, Spain, the United Kingdom, Hungary, Luxembourg, the Netherlands, Poland, Portugal, Slovenia, Slovakia, Croatia, Sweden, and Norway. Each country is considered as one market node, except for Italy, Norway, and Sweden, which consist of multiple market zones.

Spot price. In line with the literature, the hourly zonal electricity price is the shadow price of energy balance constraint.

Deterministic. The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not captured. Similarly, uncertainties concerning renewable availability factors and hydro inflows are not modelled.

The remaining of the report is organized as follows. Section 2 presents objective function, decision variables, and constraints. Section 3 offers extra sets of conditions and model formulations. Section 4 explains the input data. Finally, section 5 reviews some of the limitations of the model.

2 Model Equations

This section presents the model equations, sets, variables, parameters.

Table 1: List of sets and their descriptions

Set	Description
T	Time steps in the model
$Days$	Days in the model, e.g., 274, 275,...,365, 1, 2, 3, 4,...,273
$Node$	Set of nodes
$Consumer$	Set of consumers
$lineATC$	Set of interconnections of ATC between regions
P	Set of plants
P_{hydro}	Set of hydro plants
$P_{energymax}$	Plants with some sort of limit on energy, e.g., batteries and some biofuels
P_{inflow}	Set of storage plants with inflow/outflow, e.g., of type hydro or EV
$P_{outflow}$	Set of storage plants with inflow/outflow, e.g., of type hydro or EV
P_{allinv}	Set of all candidate power plants that can be invested in CH
$Infeedp$	Set of plants used for infeed

In Table 1, we provide a list of the sets used in our model.

In Table 2, we list the key variables used in the model along with their descriptions.

In Table 3, we list the key parameters used in the model along with their descriptions.

2.1 Objective Function

The objective function of the model is designed to minimize the total system cost, which consists of several components: investment costs, operational costs, and lost load costs. The function is defined as follows:

Table 2: List of variables and their descriptions

Variable	Description
gen	Generation (discharge of storage plant) (MWh)
soc	State of the charge (MWh)
storage_charge	Energy used to charge storage plant p in t (MWh) - charging or pumping
export	exported value on a line (ATC) from start node to end node - negative values specify imports - (MWh)
lostload	Lost load of the zone (MWh)
curtailment	Curtailment of RES generation (MWh)
spill_water	Slack variable allowing for spilling water in hydro plants to avoid infeasibility caused by storage capacity limit
gen_max	Maximum generation capacity (MW)
pmp_max	Maximum pumping capacity (MW)
gen_energy_max	Maximum storable energy (MWh) in a period/at each time step, for batteries and hydrogen plants it gives max soc, for biofuels it gives maximum energy available

Table 3: List of parameters and their descriptions

Parameter	Description
demand	Demand time series per consumer and time step
operation_slp	Operation slope cost for generating plants
operation_qdr	Operation quadratic cost for generating plants
storage_charge_eff_in	Efficiency while charging ($[0,1]$)
storage_charge_eff_out	Efficiency while discharging ($[0,1]$)
storage_start_cond	Initial/end state of charge ($[0,1]$)
inflow	Inflows to storage plants (MWh)
outflow	Outflows from storage plants (MWh)
avail_plant	Availability of plants ($[0,1]$)
energy_max	Maximum energy production in a given period (MWh)
optimization_type	Minimize cost or maximize utility for NETFLEX consumers, NA for other consumers
infeed	Fixed sum of infeed from e.g., PVs (MWh)
lostload_cost	Cost of lost load (EUR/MWh)
Map_node_plant	Map of plants to nodes
Map_node_consumer	Map of consumers to nodes
Map_node_exportinglineATC	Map of nodes to exporting lines
Map_node_importinglineATC	Map of nodes to importing lines
Map_plant_tech	Map of plants to technologies
Data_plant_flex_d_within_window	Flexibility of plants within a given time window (MWh)
sum_generation_plant_energy_limited	Sum of energy-limited generation (MWh)
gen_max_infeedp	Maximum generation capacity of pre-existing RES plants (MWh)
Map_infeedplant_tech	Map of infeed plants to technologies
Map_infeedplant_node	Map of infeed plants to nodes
gen_max_limit	Maximum generation capacity of RES plants that can be invested in CH (MW)
energy_max_limit	Maximum energy capacity of RES plants that can be invested in CH (MWh)
investment_genmax_slp	Investment cost slope for generation capacity
investment_emax_slp	Investment cost slope for energy capacity

$$\begin{aligned}
\text{Minimize: } & \sum_{p \in P_{\text{allinv}}} (\text{investment_genmax_slp}[p] \cdot \text{gen_max}[p]) \\
& + \sum_{p \in P_{\text{gen}}} \sum_{t \in T} (\text{operation_slp}[p] \cdot \text{gen}[p, t] + \text{operation_qdr}[p] \cdot \text{gen}[p, t]^2) \\
& + \sum_{c \in \text{Consumer}} \sum_{t \in T} (\text{lostload}[c, \text{tech}, t] \cdot \text{lostload_cost}[c])
\end{aligned} \tag{1}$$

The first term represents the investment costs for all investable plants. `investment_genmax_slp[p]` denotes the annualized investment cost of the power plant, i.e., the overnight investment cost discounted at a given weighted average cost of capital (default WACC value of 5%) over economic life time of the plant. The second term represents the operational costs, including both linear and quadratic costs, calculated for each generating plant over all time steps in the year. The operation slope cost for a plant p , denoted as `operation_slp[p]`, is calculated as the sum of the operation and maintenance cost, the CO₂ cost, and the fuel cost. The third term represents the cost associated with lost load for all consumers, summed over all time.

2.2 Electricity Balance

The electricity balance is the central constraint of the model (2). It ensures that at each node n and for each time step t , the sum of all energy sources, including generation, renewable energy infeed, and imports, equals the sum of all energy demands, including fixed demand, storage demand, exports, and curtailments. This balance is critical for maintaining the stability and reliability of the power system.

$$\begin{aligned}
& \sum_{p \in P_{\text{gen}} \cap \text{Map_node_plant}[n]} \text{gen}[p, t] \\
& + \sum_{l \in \text{lineATC} \cap \text{Map_node_importinglineATC}[n]} \text{Export}[l, t] \\
& + \sum_{c \in \text{Consumer} \cap \text{Map_node_consumer}[n]} \sum_{\text{tech} \in \text{Consumption_types_inflex}} \text{lostload}[c, \text{tech}, t] \\
& = \sum_{c \in \text{Consumer} \cap \text{Map_node_consumer}[n]} \sum_{\text{tech} \in \text{Consumption_types_inflex}} \text{demand}[c, \text{tech}, t] \\
& + \sum_{p \in P_{\text{pumping}} \cap \text{Map_node_plant}[n]} \text{storage_charge}[p, t] \\
& + \sum_{l \in \text{lineATC} \cap \text{Map_node_exportinglineATC}[n]} \text{Export}[l, t] \\
& + \sum_{c \in \text{Consumer_with_infeed} \cap \text{Map_node_consumer}[n]} \text{curtailment}[c, t]
\end{aligned} \tag{2}$$

In Equation 2:

- `gen[p, t]`: Represents the generation from plant p at time t .
- `infeed[c, tech, t]`: Represents the renewable energy infeed from consumer c using technology `tech` at time t .
- `demand[c, tech, t]`: Represents the fixed demand for energy by consumer c using technology `tech` at time t .
- `storage_charge[p, t]`: Represents the energy used to charge storage plant p at time t .
- `lostload[c, tech, t]`: Represents the lost load for consumer c using technology `tech` at time t .
- `Export[l, t]`: Represents the energy exported or imported through line l at time t .

- $\text{curtailment}[c, t]$: Represents the curtailment of renewable energy generation by consumer c at time t .

The hourly electricity price is defined as the shadow price of the energy balance (unit €/MWh). The shadow prices can be understood as the market-clearing zonal spot price as being implemented in many deregulated wholesale electricity pool markets. In our case, cost minimization is equivalent to welfare-maximization, and the shadow prices can also be interpreted as the marginal social benefit of electricity.

2.3 Model Constraints

The model is subject to several constraints that ensure the proper functioning and feasibility of the optimization process. Below is a detailed description of each constraint, including the sets over which they are defined.

2.3.1 Generation Limit

The generation limit constraint ensures that the generation of each plant $p \in P_{\text{gen}}$ at time $t \in T$ does not exceed the product of its maximum generation capacity and its availability at that time. This constraint is defined as:

$$\text{gen}[p, t] \leq \text{gen_max}[p] \times \text{avail_plant}[p, t] \quad (3)$$

2.3.2 Storage State of Charge (SOC) Balance

The SOC balance constraint ensures that the state of charge (SOC) of a storage plant $p \in P_{\text{storage}}$ at time $t \in T$ is correctly updated based on its previous state, the energy charged, discharged, and any inflows or outflows. The equation is given by:

$$\text{soc}[p, t] + \text{slack_neg} = \text{soc}[p, t-1] + \text{charged} - \text{discharged} + \text{inflow} - \text{outflow} + \text{slack_pos} - \text{spill_energy} \quad (4)$$

2.3.3 Storage Start Condition

This constraint ensures that the initial state of charge of storage plants $p \in P_{\text{storage}}$ follows predefined start conditions. For most plants, this is an equality constraint, while for electric vehicles (EVs), it is an inequality to avoid infeasibility. The constraint is defined as:

$$\text{soc}[p, T.\text{at}(1)] = \text{storage_start_cond}[p] \times \text{gen_energy_max}[p] \quad (5)$$

2.3.4 Storage Charge Power Limit

The storage charge power limit constraint ensures that the charging rate of storage plants $p \in P_{\text{pumping}}$ at time $t \in T$ does not exceed their maximum charging capacity, considering their availability. The constraint is defined as:

$$\text{storage_charge}[p, t] \leq \text{pmp_max}[p] \times \text{avail_plant}[p, t] \quad (6)$$

2.3.5 Maximum Capacity Equalization

This constraint ensures that the maximum charging rate of storage plants $p \in P_{\text{equal.p.g.max}}$ does not exceed their maximum generation capacity. The equation is:

$$\text{pmp_max}[p] \leq \text{gen_max}[p] \quad (7)$$

2.3.6 Storage SOC Limit

This constraint ensures that the state of charge of storage plants $p \in P_{\text{storage}}$ at time $t \in T$ does not exceed their maximum energy capacity. The constraint is given by:

$$\text{soc}[p, t] \leq \text{gen_energy_max}[p] \quad (8)$$

2.3.7 Lost Load Limit

The lost load limit constraint ensures that the lost load for each consumer $c \in \text{Consumer}$ using technology $\text{tech} \in \text{Consumption_types_inflex}$ at time $t \in T$ does not exceed their fixed demand. The constraint is defined as:

$$\text{lostload}[c, \text{tech}, t] \leq \max(\text{demand}[c, \text{tech}, t], 0) \quad (9)$$

2.3.8 Curtailment Limit

The curtailment limit ensures that the curtailment of renewable energy sources (RES) for each consumer $c \in \text{Consumer_with_infeed}$ at time $t \in T$ does not exceed the sum of the RES generation and infeed from consumers. The constraint is given by:

$$\text{curtailment}[c, t] \leq \max \left(0, \sum_{\text{tech} \in \text{Tech_infeed}} \text{infeed}[c, \text{tech}, t] \right) + \sum_{\substack{p \in P_{\text{gen}} \\ p \in \text{Plant_investment_RES_CH_list}}} \text{gen}[p, t] \quad (10)$$

2.3.9 Energy Limit for Limited Energy Technologies

This constraint limits the total energy generation over the year for plants $p \in P_{\text{energylim}}$ with limited energy availability. The constraint is:

$$\sum_{t \in T} \text{gen}[p, t] \leq \text{sum_generation_plant_energy_limited}[p] \times \frac{\text{len}(T)}{8760} \quad (11)$$

2.3.10 Daily Energy Shift Limit for Demand-Side Response (DSR)

The DSR daily energy shift limit ensures that the total energy shifted by DSR technologies $p \in P_{\text{dsr}}$ within a day $d \in \text{Days}$ does not exceed N times their maximum generation capacity. The constraint is:

$$\sum_{\substack{t \in T \\ \text{in day } d}} \text{gen}[p, t] + \sum_{\substack{t \in T \\ \text{in day } d}} \text{storage_charge}[p, t] \leq N \times \text{gen_max}[p] \quad (12)$$

2.3.11 Daily Balance for DSR Technologies

This constraint ensures that the total energy generated by DSR technologies $p \in P_{\text{dsr}}$ within a day $d \in \text{Days}$ equals the total energy consumed. The equation is:

$$\sum_{\substack{t \in T \\ \text{in day } d}} \text{gen}[p, t] = \sum_{\substack{t \in T \\ \text{in day } d}} \text{storage_charge}[p, t] \quad (13)$$

2.3.12 Generation Capacity Investment Limit

This constraint limits the maximum generation capacity that can be invested in for certain technologies $p \in P_{\text{allinv}}$. The constraint is:

$$\text{gen_max}[p] \leq \text{gen_max_limit}[p] \quad (14)$$

This constraint allows to define a maximum potential for investment in a given technology in a region.

2.3.13 Energy Capacity Investment Limit

This constraint limits the maximum energy storage capacity that can be invested in for certain technologies $p \in P_{\text{allinv}}$. The constraint is given by:

$$\text{gen_energy_max}[p] \leq \text{energy_max_limit}[p] \quad (15)$$

2.3.14 Line NTC Limits

The line NTC limits ensure that the power flow on each transmission line does not exceed the specified export and import limits. This constraint is defined over the sets of transmission lines $l \in \text{lineATC}$ and time periods $t \in T$.

$$-\text{lower_bound} \leq \text{Export}[l, t] \leq \text{upper_bound} \quad (16)$$

3 Optional constraints and alternative problem formulation

3.1 Optional constraints

FEM is designed with flexibility to accommodate various scenario-specific constraints. Several optional constraints are already integrated into the model's framework, allowing for their activation based on the requirements of the particular scenario under analysis.

3.1.1 Winter Energy Limit Constraint

This constraint imposes a limit on the total energy imported into Switzerland during a specified winter period. The constraint ensures that the total energy imported minus the total energy exported during this period does not exceed a given limit. The constraint is defined over the set of transmission lines $l \in \text{lineATC}$ and the winter time window $t \in T_{\text{winter}}$:

$$\begin{aligned} \sum_{l \in \text{lineATC}} \sum_{t \in T_{\text{winter}}} \text{Export}[l, t]_{\text{import_as_ending_node}} \\ - \sum_{l \in \text{lineATC}} \sum_{t \in T_{\text{winter}}} \text{Export}[l, t]_{\text{export_as_starting_node}} \\ \leq \text{winter_limit}[\text{energy_MWh}] \end{aligned} \quad (17)$$

3.1.2 Minimum RES Target Constraint for Switzerland

This constraint ensures that the total infeed and generation from renewable energy sources (RES) in Switzerland (node CH00) meets or exceeds a predefined minimum target. The constraint is defined over the sets of consumers $n \in \text{Map_node_consumer}["\text{CH00}"]$, technologies $tech \in \text{Tech_infeed}$, and time periods $t \in T$:

$$\begin{aligned} \sum_{n \in \text{Map_node_consumer}["\text{CH00}"]} \sum_{tech \in \text{Tech_infeed}} \sum_{t \in T} \text{infeed}[n, tech, t] \\ + \sum_{plant \in \text{Plant_investment_RES_CH_list}} \sum_{t \in T} \text{gen_max}[plant] \times \text{avail_plant}[plant, t] \\ \geq \text{minimum_RES_target_CH} \end{aligned} \quad (18)$$

3.2 Alternative problem formulation

3.2.1 Household centeric

The primary model formulation does not explicitly model households, their inflexible and flexible behavior (e.g., stemming from the use of batteries), or their responses to electricity tariffs. Instead, households are implicitly modeled, as the input demand data already account for such potential behaviors. In contrast, the household-centric approach explicitly models households consumption profile, assets and flexibilities in two different ways: **tariff-based approach** and **centrally controlled approach**.

In the **tariff-based approach**, as depicted in Figure 1, two distinct submodules are developed: one dedicated to households and another for the wholesale electricity market. This approach allows for a more detailed representation of household behaviors and their interactions with the electricity market:

- **Household sub-module:** A set of household models capturing the incentives for electricity usage on the end consumer side for the different consumers based on a direct costs-minimization approach with externally defined tariffs.
- **wholesale market sub-module:** A wholesale market model combining the household demand with the further system parameters to derive the overall cost-minimal system dispatch and the resulting market prices, linking the Swiss and European markets.

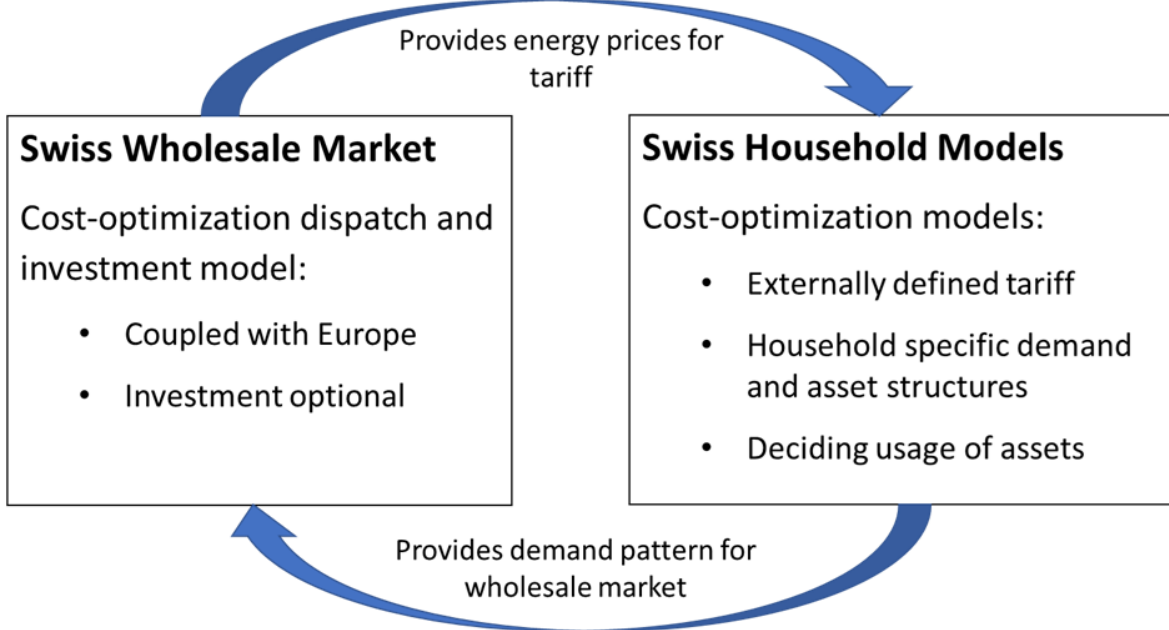


Figure 1: Schematic structure of the model formulation with independent household decisions

The two model modules are combined in a looping structure. The household tariffs are based on the energy prices of the wholesale market model (including network charges, taxes and levies on top). The derived household demand profile is in turn provided to the wholesale model as fixed input. The model loop stops when there is either no change between the loops anymore in terms of energy prices and household demand, or the model switches between two states.

This setting allows the direct modelling of market policies that are based on tariff structures for households and an energy market as main system price signal. The system layer could also be extended to require specific capacity requirements or the investment options or could include additional payment elements (i.e. subsidies or technology restrictions) to capture different policy options.

On the other hand, in the **centrally controlled approach**, the household module is ignored and the relevant household information (i.e. available assets and flexibility options) is included in the wholesale system layer. The resulting overall system optimization represents the first best system benchmark, which in turn can be interpreted as the result of a contractual setting with consumers, retailers and generators as presented in Section 3.

Household Model The household model is designed as a simple cost minimization setting for a full year with an hourly time resolution. For each household demand is structured in a fixed and flexible part. Given the tariff structure the household decides how much of the flexible demand is shifted in time to minimize the tariff payments. The infrastructure of each household is pre-defined; in other words, households only decide about their usage not about their investments. The basic model structure is the same for each household, while the data for assets, inflexible, and flexible demand varies. The underlying household dataset is derived from the NETFLEX project and includes 300 representative households from the canton Aargau with their respective asset composition (PV, battery, EV, and heat pump) and PV generation and demand time series (see <https://doi.org/10.3390/en17061364>).

On the flexibility side the households can have electric vehicles (EVs), a heat pump, and battery storage:

- For EVs, a predefined mobility demand is given (based on the NETFLEX data). However, the charging behavior of the EV batteries can be defined to capture different flexibility levels; i.e., fixed charging to refill the battery whenever connected, flexible charging in a given time window like a day or week, or bi-directional charging. For the scenarios, we only allow charging of cars and provide a weekly time window.
- For heat pumps, the heat demand is given for a predefined time window (based on the NETFLEX data), while the electricity consumption to satisfy this demand can be freely chosen within the time window. Detailed thermal or further technical restrictions are neglected, and an hourly capacity limit of the heat pump has been derived from the hourly thermal demand curve. For the scenarios, we assume a time window of six hours for heat pump operation flexibility.
- Batteries can be freely charged and discharged if available, to optimize the overall energy usage of the household. We assume a battery efficiency of 81% (90% each way).

On the provision side, each household has unrestricted grid access and can have PV capacity:

- For PV panels, a weather-dependent hourly injection profile is given that is based on the Aargau dataset (i.e., there are slight variations in orientation and angle between the different households, however, the majority are south-facing).
- For electricity consumption from the grid, no direct physical limitation is assumed. However, in case of EV charging, a maximum charging capacity of 11 kW (on top of the other electricity usages in the household) is assumed. Household tariffs are predefined, and for the scenarios, we use a peak/off-peak structure (i.e., hours between 8 and 20 during weekdays and Saturday are part of the peak period) differentiated for summer and winter.

3.2.2 Robust formulation

The objective function is designed to minimize the total *expected* investments and operations costs across various scenarios. A set of *Scenarios* are exogenously defined with given probabilities denoted as $\text{weight}_{\text{scen}}$. This modified objective function balances the trade-offs between capital investments in generation and energy storage capacities, operational costs of running the power system, and the costs associated with unserved energy (lost load). The minimization occurs over all possible scenarios, with the operational costs of each scenario weighted according to its $\text{weight}_{\text{scen}}$. The optimization problem can be defined as follows:

$$\begin{aligned}
\text{Minimize: } & \sum_{p \in P_{\text{allinv}}} \left(\text{investment_genmax_slp}_p \times \text{gen_max}_p + \text{investment_enmax_slp}_p \times \text{en_max}_p \right) \\
& + \sum_{\text{scen} \in \text{Scenarios}} \text{weight}_{\text{scen}} \times \left[\right. \\
& \sum_{p \in P_{\text{gen}}} \sum_{t \in T} \left(\text{operation_slp}_{p,\text{scen}} \times \text{gen}_{p,t,\text{scen}} + \text{operation_qdr}_{p,\text{scen}} \times \text{gen}_{p,t,\text{scen}}^2 \right) \\
& \left. + \sum_{t \in T} \text{lostload}_{t,\text{scen}} \times \text{lostload_cost}_c \right] \\
& s.t.: \text{ constraints of scen } \quad \forall \text{ scen} \in \text{Scenarios}
\end{aligned}$$

Investment Costs: The first term in the objective function accounts for the capital investments in both generation capacity (gen_max_p) and energy storage capacity (en_max_p). The term $\text{investment_genmax_slp}_p$ represents the slope of the investment cost function for generation capacity p , while $\text{investment_enmax_slp}_p$ represents the slope of the investment cost function for energy storage capacity p . These costs are summed over all potential investment options, i.e., various generation and storage technologies.

Operational Costs: The second term captures the operational costs of generating electricity, which include both linear and quadratic cost components. $\text{operation_slp}_{p,\text{scen}}$ is the linear component of the operational cost for generation unit p in scenario scen , and $\text{gen}_{p,t,\text{scen}}$ represents the actual power generation by unit p at time t in scenario scen . The quadratic component, $\text{operation_qdr}_{p,\text{scen}}$, accounts for non-linearities such as fuel cost curves, with $\text{gen}_{p,t,\text{scen}}^2$ capturing the increasing marginal cost of generation. These operational costs are weighted by the scenario likelihood and summed across all scenarios and time periods.

Lost Load Costs: The final term in the objective function represents the economic costs associated with unserved demand (lost load) across all scenarios and time periods. $\text{lostload}_{t,\text{scen}}$ indicates the amount of demand that is unmet at time t in scenario scen , while lostload_cost_c denotes the cost per unit of lost load, which may vary depending on the type of consumer affected. These costs are also weighted by the scenario likelihood.

Summary: The objective function aims to minimize the total cost of investment, operation, and unserved energy, considering the probability-weighted scenarios. This comprehensive approach ensures that the power system is designed and operated in a cost-effective manner, while also accounting for the potential risks of unanticipated demand shortfalls.

4 Input Data

The input data comprises several time series (e.g., demand, renewable availability factor), annually fixed values (e.g., installed generation capacities), as well as scalar cost parameters. Table 4 summarizes key parameters and sources, which are further described below.

Table 4: Key parameters and sources

Topic	Parameter	Source
Time series	Hourly electricity demand	ENTSO-E, TYNDP 2022 https://2022.entsos-tyndp-scenarios.eu/download/
	Availability factor for photo-voltaics, onshore and offshore wind and solar technologies	Joint Research Centre: EMHIRES dataset https://doi.org/10.5281/zenodo.8340500
	Hydro inflow and run-of-river generation	ENTSO-E Pan-European Climatic Database (PECD 2021.3) https://zenodo.org/record/7224854
	Availability factor of conventional power plants	Swissmod http://dx.doi.org/10.2139/ssrn.2446807
Annual values	Annual electricity demand	Switzerland: Federal Office of Energy, Energy perspectives 2050+ https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/ Rest: ENTSO-E, TYNDP 2022 https://2022.entsos-tyndp-scenarios.eu/download/
	Annual electricity generation (for energy-limited technologies, e.g., biomass)	Switzerland: Federal Office of Energy, Energy perspectives 2050+ https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/ Rest: ENTSO-E, TYNDP 2022 https://2022.entsos-tyndp-scenarios.eu/download/

Table 4: Key parameters and sources (continued)

Topic	Parameter	Source
	Installed generation capacities	Hydro generation: ENTSO-E Pan-European Climatic Database (PECD 2021.3) https://zenodo.org/record/7224854 Switzerland: Federal Office of Energy, Energy perspectives 2050+ https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/ Rest: ENTSO-E, TYNDP 2022 https://2022.entsos-tyndp-scenarios.eu/download/
	Net Transfer Capacities (NTCs)	ENTSO-E, TYNDP 2022 https://2022.entsos-tyndp-scenarios.eu/download/
Costs	Investment costs	Battery and hydrogen electricity storage: Swiss-Calliope https://zenodo.org/doi/10.5281/zenodo.10887522 Nuclear: LAZARD levelized cost of energy https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf Rest: NEXUS-E, ETH https://nexus-e.org/documentation/
	Fuel and CO2 costs	Federal Office of Energy, Energy perspectives 2050+ https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/
	Operational costs	Swissmod http://dx.doi.org/10.2139/ssrn.2446807

Time series. Each region’s electricity demand and availability factors of wind and solar are described using hourly resolution. For the case of regions in Switzerland, demand time series are scaled so that annual demand per region matches the annual demand values reported in Energy Perspective 2050+ (see ”Annual values” in the Table 4). Hydro inflows and run-of-river generations are provided in weekly and daily resolution, respectively. Above-mentioned time series are available for different weather years. Availability factor of conventional power plants are adjusted to represent historical values.

Annual values. Annual demand for Switzerland is used to scale time series provided in ENTSO-E TYNDP 2022 (see ”Times series” the Table 4). Moreover, annual demand of electrolyzer plants are obtained from ENTSO-E TYNDP 2022 and Energy Perspective 2050+. Such plants are fixed to consume the predefined electricity flexibly throughout the year. On the other hand, annual generations from fuel-limited technologies (e.g., biomass) is also fixed to reported annual values from the data sources. The pre-existing generation capacities of the hydro power plants are fixed to values provided by ENTSO-E Pan-European Climatic Database so that hydro inflow and generation capacities follow a consistent data source. Other European generation capacities are fixed to ENTSO-E TYNDP 2022 values. Finally, for future scenarios, the pre-existing Swiss power plants are fixed to values assumed by Energy Perspective 2050+. Further investments in Switzerland may be allowed in the model. Finally, existing net transfer capacity and planned network expansions are taken from ENTSO-E TYNDP 2022.

Costs. Overnight investment costs and economic life times of storage technologies (battery and power-to-hydrogen-to-power closed loop) plants are obtained from the energy model Swiss-Calliope. For the nuclear power technology, the average estimated investment cost from LAZARD’s study is used (i.e., 10’600’000 EUR/MW). For the rest of the generation technologies, overnight investment costs

and economic life times are coordinated with NEXUS-E model developed by the ETH University. For all technologies, a WACC of 5% is assumed while calculating the annualized investment costs. Fuel and CO2 costs are obtained from Energy Perspectives 2050+. Other operational costs (EUR/MWh) are obtained from the dataset developed by Swissmod.

5 Model Limitations

As with all models, FEM is based on several simplifications and assumptions that influence the results and can impact the derived insights. One main simplification compared to real world systems is the deterministic nature of the model. As the full year is modelled with perfect foresight, the model results represent an upper benchmark of how the system can manage the different supply and demand situations. In this regard, the model results have an optimism bias.

Moreover, the model relies on simplifications like using technology blocks (instead of individual power plants' characteristics), average input costs, neglecting unit commitment details, perfect competition (ignoring the possibility of market power), ignoring grid constraints at the intra-regional transmission and distribution level, and any effects related to lumpiness or economies of scale of investments.