EnergyScope TD: a novel open-source model for regional energy systems [1] Supplementary Material

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Introduction

This Supplementary Material presents the complete formulation of the energy model (Section 1). In addition, all the data used for the case and their sources are presented in Section 2. Finally, in Section 3, a *User manual* is proposed to understand the repository structure and how to use the code. The latest version of this Supplementary Material is available on the repository[1].

1 Linear programming formulation

The model is mathematically formulated as a linear programming (LP) problem [2]. We use the following nomenclature: *SETS* are in italic capital letters, *parameters* are in italic lower letters and **Variables** are bold in lower letter, with the first letter in capital (e.g. $\mathbf{C_{tot}}$). *SETS* are collections of distinct items (as in the mathematical definition), e.g. the *RESOURCES* set regroups all the available resources (NG, WOOD, etc.). *Parameters* are known values (inputs) of the model, such as the demand or the resource availability. The value of the decision variables is determined (optimized) by the solver within an upper and a lower bound (the latter being parameters). As an example, the quantity of installed wind turbines is a decision variable; this quantity is bounded between 0 and the maximum available potential. *Decision variables* can be split in two categories: independent decision variables, which can be freely fixed, and dependent decision variables, which are linked via equality constraints to the previous ones. As an example the investment cost for wind turbines is a variable but it directly depends on the number of wind turbines, which is an independent decision variable. *Constraints* are inequality or equality restrictions that must be satisfied. Constraints can enforce, for example, an upper limit for the availability of resources, energy or mass balance, etc. Finally, an *objective function* is a particular constraint whose value is to be maximised (or minimised).

1.1 Conceptual modelling framework

The proposed modelling framework is a simplified representation of an energy system accounting for the energy flows within its boundaries. Its primary objective is to satisfy the energy balance constraints, meaning that the demand is known and the supply has to meet the demand. In the energy modelling practice, the energy demand is often expressed in terms of final energy consumption (FEC). According to the definition of the European commission, FEC is defined as "*the energy which reaches the final consumer's door*" [3]. In other words, the FEC is the amount of input energy needed to satisfy the end-use demand (EUD) in energy services. As an example, in the case of decentralized heat production with a natural gas (NG) boiler, the FEC is the amount of NG consumed by the boiler; the EUD is the amount of heat produced by the boiler, i.e. the heating service needed by the final user.

The input for the proposed modelling framework is the EUD in energy services, represented as the sum of three components: electricity, heating and mobility; this replaces the classical sector-based representation of energy demand. Heat is divided in three end-use types (EUTs): high temperature heat for industry demand, low temperature for space heating and low temperature for hot water. Mobility is divided in two EUTs: passenger mobility and freight.

A simplified conceptual example of the proposed energy system structure is proposed in Figure 1.

The system is separated in three parts: resources, energy conversion and demand. In this illustrative example, resources are solar energy, electricity and NG. The EUD are electricity,

[1]Repository: `https://github.com/energyscope/EnergyScope/tree/v2.0`

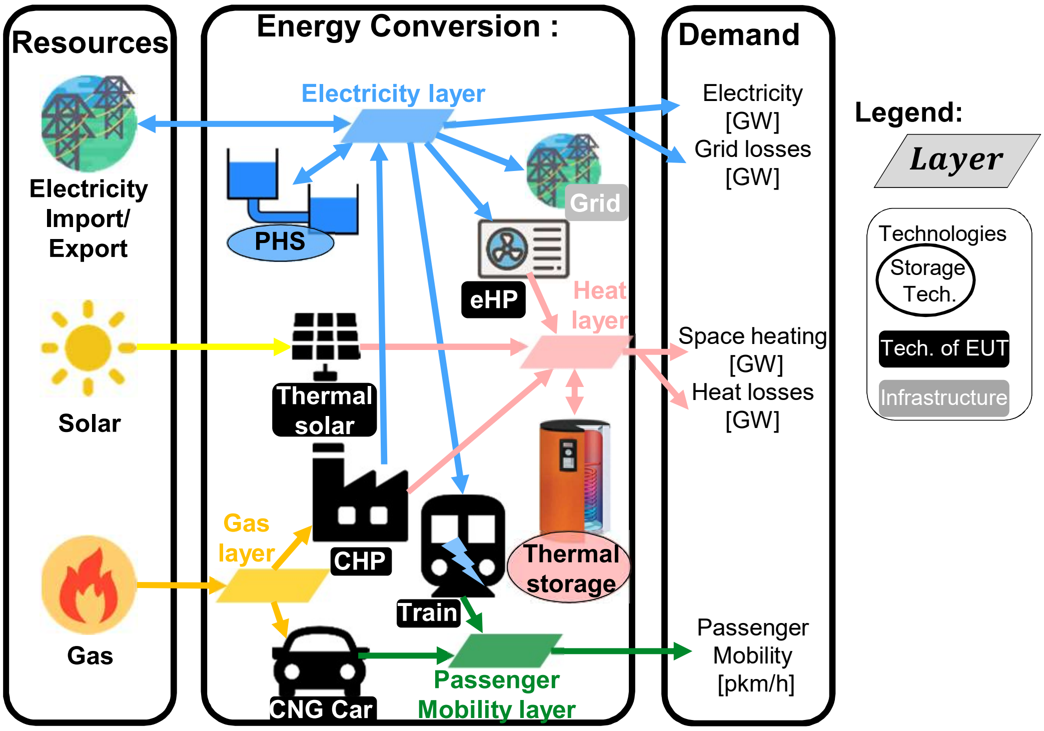


Figure 1: Conceptual example of an energy system with 3 resources, 8 technologies (of which 2 storage and 1 infrastructure) and 4 end use demand (of which 1 losses). Abbreviations: pumped hydro storage (PHS), electrical heat pump (eHP), combined heat and power (CHP), compressed natural gas (CNG). Some icons are form [4].

space heating and passenger mobility. The energy system encompasses all the energy conversion technologies needed to transform resources and supply EUD. In this example, Solar and NG resources cannot be directly used to supply heat. Thus, they use technologies, such as boilers or combined heat and power (CHP) for NG, to supply the EUT layer (e.g. the high temperature industrial heat layer). *Layers* are defined as all the elements in the system that need to be balanced in each time period; they include resources and EUTs. An an example, the electricity layer must be balanced at any time, meaning that the production and storage must equal the consumption and losses. These layers are connected to each other by *technologies*. We define three types of technologies: *technologies of end-use type*, *storage technologies* and *infrastructure technologies*. A technology of end-use type can convert the energy (e.g. a fuel resource) from one layer to a EUT layer, such as a CHP unit that converts NG into heat and electricity. A storage technology converts energy from a layer to the same one, such as thermal storage (TS) that stores heat to provide heat. In this example, there are two storage technologies: TS for heat and pumped hydro storage (PHS) for electricity. An infrastructure technology regroups the remaining technologies including grids, such as the power grid and district heating networks (DHNs), but also technologies linking non end-use layers, such as methane production from wood gasification or hydrogen production from methane reforming.

As an illustrative example of the concept of *layer*, Figure 2 gives a perspective of the electricity layer which is the most complex one, since the electrification of other sectors is foreseen as a key of the energy transition [5]. In the proposed version, 38 technologies are related to the electricity layer. 13 technologies produce exclusively electricity, such as natural gas combined cycle (CCGT), photovoltaic (PV) or wind. 10 combined heat and power (CHP) produce heat and electricity, such as industrial waste CHP. 1 infrastructure represents the grid. 5 storage technologies are implemented, such as PHS, hydro dams, batteries or vehicle-to-grid (V2G). The rest are consumers regrouped in the electrification of heat and mobility. Electrification of the heating sector is supported by direct electric heating but also by the more expensive but more efficient electrical heat pumps for low temperature heat demand. All the data for technologies and resources are reported in detail in Appendix 2. Electrification of mobility is achieved via electric public transportation (train, trolley, metro and electrical/hybrid buses), electric private transportation with the promising vehicle-to-grid (V2G) and hydrogen cars[2] and trains for freight.

1.2 Sets, parameters and variables

Figure 3 gives a visual representation of the sets with their relative indices used throughout the paper.

In order to solve a yearly problem over 8760h, we define the sets $H\_OF\_T(t)$, $TD\_OF\_T(t)$ and $T\_H\_TD(t)$ that give respectively, the hour (h), the typical day (td) or both (h,td) based on the period (t). E.g. if January 2 is associated to typical day 1, then $H\_OF\_T(34) = 10$, $TD\_OF\_T(t) = 1$ and $T\_H\_TD(34) = \{h = 10, td = 1\}$.

Tables 1 and 2 list and describe the model parameters. Tables 3 and 4 list and describe the independent and dependent variables, respectively.

[2] Hydrogen can be produced by electrolysers; thus, the energy comes from electricity.

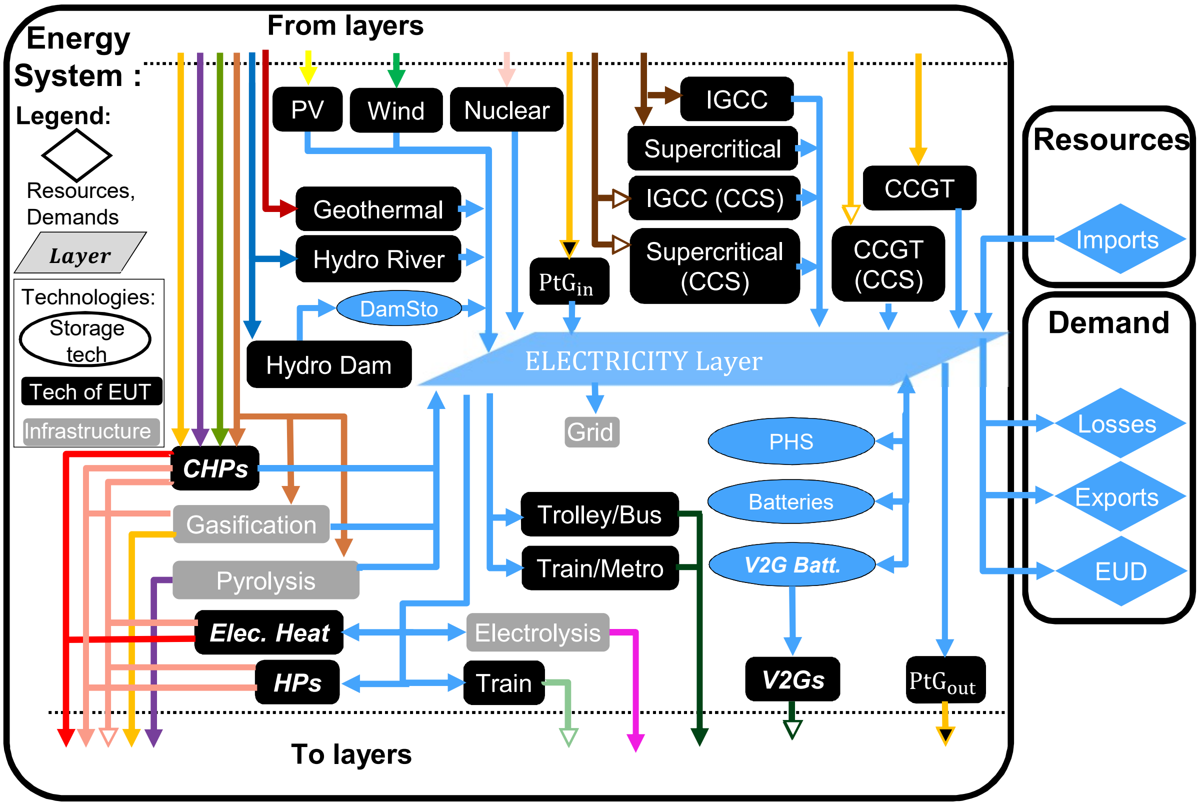


Figure 2: Representation of the Elec layer with all the technologies implemented in EnergyScope TDs. ***Bold Italic technologies*** represent a group of different technologies. Refer to Figure 6 of the main paper for color legend. Abbreviations: photovoltaic (PV), gas to power (GtP), integrated gasification natural gas combined cycle (IGCC), carbon capture and storage (CCS), natural gas combined cycle (CCGT), combined heat and power (CHP), heat pump (HP), pumped hydro storage (PHS), vehicle-to-grid (V2G), power to gas (PtG), end-use demand (EUD).

Table 1: Time series parameter list with description. Set indices as in Figure 3

Parameter	Units	Description
$\%_{elec}(h, td)$	[-]	Yearly time series (adding up to 1) of electricity end-uses
$\%_{sh}(h, td)$	[-]	Yearly time series (adding up to 1) of SH end-uses
$\%_{pass}(h, td)$	[-]	Yearly time series (adding up to 1) of passenger mobility end-uses
$\%_{fr}(h, td)$	[-]	Yearly time series (adding up to 1) of freight mobility end-uses
$c_{p,t}(tech, h, td)$	[-]	Period capacity factor (default 1)

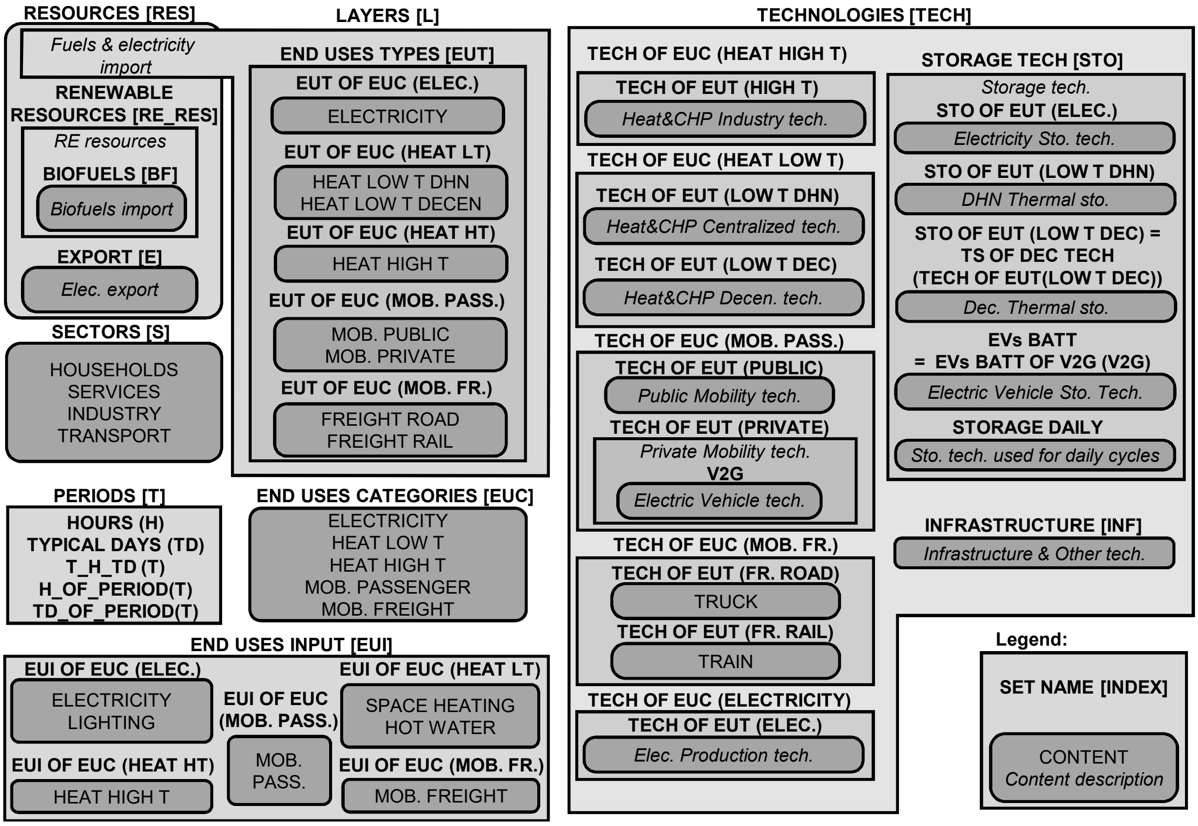


Figure 3: Visual representation of the sets and indices of the LP framework. Abbreviations: space heating (SH), hot water (HW), temperature (T), mobility (MOB), vehicle-to-grid (V2G), thermal storage (TS).

Table 2: Scenario parameter list with description. Set indices as in Figure 3

Parameter	**Units**	**Description**
$\tau(tech)$	[-]	Investment cost annualization factor
i_{rate}	[-]	Real discount rate
$endUses_{year}(eui, s)$	[GWh/y][a]	Annual end-uses in energy services per sector
$endUsesInput(eui)$	[GWh/y][a]	Total annual end-uses in energy services
re_{share}	[-]	minimum share [0;1] of primary RE
gwp_{limit}	[$ktCO_{2\text{-eq}}$/y]	Higher $CO_{2\text{-eq}}$ emissions limit
$\%_{public,min}, \%_{public,max}$	[-]	Lower and upper limit to $\%_{\textbf{Public}}$
$\%_{rail,min}, \%_{rail,max}$	[-]	Lower and upper limit to $\%_{\textbf{Rail}}$
$\%_{dhn,min}, \%_{dhn,max}$	[-]	Lower and upper limit to $\%_{\textbf{DHN}}$
$t_{op}(h, td)$	[h]	Time periods duration (default 1h)
$f_{min}, f_{max}(tech)$	[GW][ab]	Min./max. installed size of the technology
$f_{min,\%}, f_{max,\%}(tech)$	[-]	Min./max. relative share of a technology in a layer
$avail(res)$	[GWh/y]	Resource yearly total availability
$c_{op}(res)$	[MCHF/GWh]	Specific cost of resources
$n_{car,max}$	[-]	Maximum number of cars
$\%_{Peak_{sh}}$	[-]	Ratio peak/max. space heating demand in typical days
$f(res \cup tech \setminus sto, l)$	[GW][c]	Input from (< 0) or output to (> 0) layers. $f(i, j) = 1$ if j is main output layer for technology/resource i
$c_{inv}(tech)$	[MCHF/GW][cb]	Technology specific investment cost
$c_{maint}(tech)$	[MCHF/GW/y][cb]	Technology specific yearly maintenance cost
$lifetime(tech)$	[y]	Technology lifetime
$gwp_{constr}(tech)$	[$ktCO_2$-eq./GW][ab]	Technology construction specific GHG emissions
$gwp_{op}(res)$	[$ktCO_2$-eq./GWh]	Specific GHG emissions of resources
$c_p(tech)$	[-]	Yearly capacity factor
$\eta_{sto,in}, \eta_{sto,out}(sto, l)$	[-]	Efficiency $[0; 1]$ of storage input from/output to layer. Set to 0 if storage not related to layer.
$\%_{sto_{loss}}(sto)$	[1/h]	Losses in storage (self discharge)
$t_{sto_{in}}(sto)$	[-]	Time to charge storage (Energy to power ratio)
$t_{sto_{out}}(sto)$	[-]	Time to charge storage (Energy to power ratio)
$\%_{sto_{avail}}(sto)$	[-]	Storage technology availability to charge/discharge
$\%_{net_{loss}}(eut)$	[-]	Losses coefficient $[0; 1]$ in the networks (grid and DHN)
$ev_{Batt,size}(v2g)$	[GWh]	Battery size per V2G car technology
$c_{grid,extra}$	[MCHF]	Cost to reinforce the grid due to IRE penetration

[a] [Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses
[b] [GWh] if $tech \in STO$
[c] [Mpkm/h] for passenger, [Mtkm/h] for freight mobility end-uses

Table 3: Independent variable list with description. All variables are continuous and non-negative, unless otherwise indicated.

Variable	Units	Description
$\boldsymbol{\%_{Public}}$	[-]	Ratio $[0;1]$ public mobility over total passenger mobility
$\boldsymbol{\%_{Rail}}$	[-]	Ratio $[0;1]$ rail transport over total freight transport
$\boldsymbol{\%_{DHN}}$	[-]	Ratio $[0;1]$ centralized over total low-temperature heat
$\mathbf{F}(tech)$	$[\mathrm{GW}]^{ab}$	Installed capacity with respect to main output
$\mathbf{F_t}(tech \cup res, h, td)$	$[\mathrm{GW}]^{ab}$	Operation in each period
$\mathbf{Sto_{in}}, \mathbf{Sto_{out}}(sto, l, h, td)$	[GW]	Input to/output from storage units
$\mathbf{P_{Nuc}}$	[GW]	Constant load of nuclear
$\boldsymbol{\%_{MobPass}}(\mathit{TECH\ OF\ EUC(MobPass)})$	[-]	Constant share of passengers mobility
$\boldsymbol{\%_{HeatDec}}(\mathit{TECH\ OF\ EUT(}\mathit{(HeatLowTDEC)}\setminus\{\mathrm{Dec_{Solar}}\})$	[-]	Constant share of Heat low T decentralised supplied by a technology plus its associated thermal solar and storage
$\mathbf{F_{sol}}(\mathit{TECH\ OF\ EUT(}\mathit{(HeatLowTDEC)}\setminus\{\mathrm{Dec_{Solar}}\})$	[GW]	Solar thermal installed capacity associated to a decentralised heating technology
$\mathbf{F_{t_{sol}}}(\mathit{TECH\ OF\ EUT(}\mathit{(HeatLowTDEC)}\setminus\{\mathrm{Dec_{Solar}}\})$	[GW]	Solar thermal operation in each period

[a] [Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses
[b] [GWh] if $tech \in STO$

Table 4: Dependent variable list with description. All variables are continuous and non-negative, unless otherwise indicated.

Variable	Units	Description
$\mathbf{EndUses}(l, h, td)$	$[\mathrm{GW}]^{a}$	End-uses demand. Set to 0 if $l \notin EUT$
$\mathbf{C_{tot}}$	[MCHF/y]	Total annual cost of the energy system
$\mathbf{C_{inv}}(tech)$	[MCHF]	Technology total investment cost
$\mathbf{C_{maint}}(tech)$	[MCHF/y]	Technology yearly maintenance cost
$\mathbf{C_{op}}(res)$	[MCHF/y]	Total cost of resources
$\mathbf{GWP_{tot}}$	[ktCO$_2$-eq./y]	Total yearly GHG emlissions of the energy system
$\mathbf{GWP_{constr}}(tech)$	[ktCO$_2$-eq.]	Technology construction GHG emissions
$\mathbf{GWP_{op}}(res)$	[ktCO$_2$-eq./y]	Total GHG emissions of resources
$\mathbf{Net_{loss}}(eut, h, td)$	[GW]	Losses in the networks (grid and DHN)
$\mathbf{Sto_{level}}(sto, t)$	[GWh]	Energy stored over the year

[a] [Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses

1.3 Linear Programming model formulation

The energy system is formulated as a linear programming (LP) problem. It optimises the design by computing the installed capacity of each technology, as well as the operation in each period, to meet the energy demand and minimize the total annual cost of the system. In the following, we present the complete formulation of the model. It accounts for sets, parameters, variables, constraints and the objective function. The model formulation is expressed by the equations in Figure 4 and Eqs. (1)-(42).

End-use demand

We use the end-use demand (EUD) instead of the final energy consumption (FEC) to characterise the demand. According to the definition of the European commission, FEC is defined as "*the energy which reaches the final consumer's door*" [3]. In other words, the FEC is the amount of input fuel needed to satisfy the EUD in energy services. As an example, in the case of decentralized heat production with a gas boiler, the FEC is the amount of NG consumed by the boiler; the EUD is the amount of heat produced by the boiler, i.e. the heating service needed by the final user. This modelling choice has two advantages. First, it introduces a clear distinction between demand and supply. On the one hand, the demand concerns the definition of the end-uses, i.e. the requirements in energy services (e.g. the mobility needs). On the other hand, the supply concerns the choice of the energy conversion technologies to supply these services (e.g. the types of vehicles used to satisfy the mobility needs). Based on the technology choice, the same EUD can be satisfied with different FEC, depending on the efficiency of the chosen energy conversion technology. Second, it facilitates the inclusion in the model of electric technologies for heating and transportation.
The hourly end-use demand (**EndUses**) is computed based on the yearly end-use demand (*endUsesInput*), distributed according to a normalised time series.

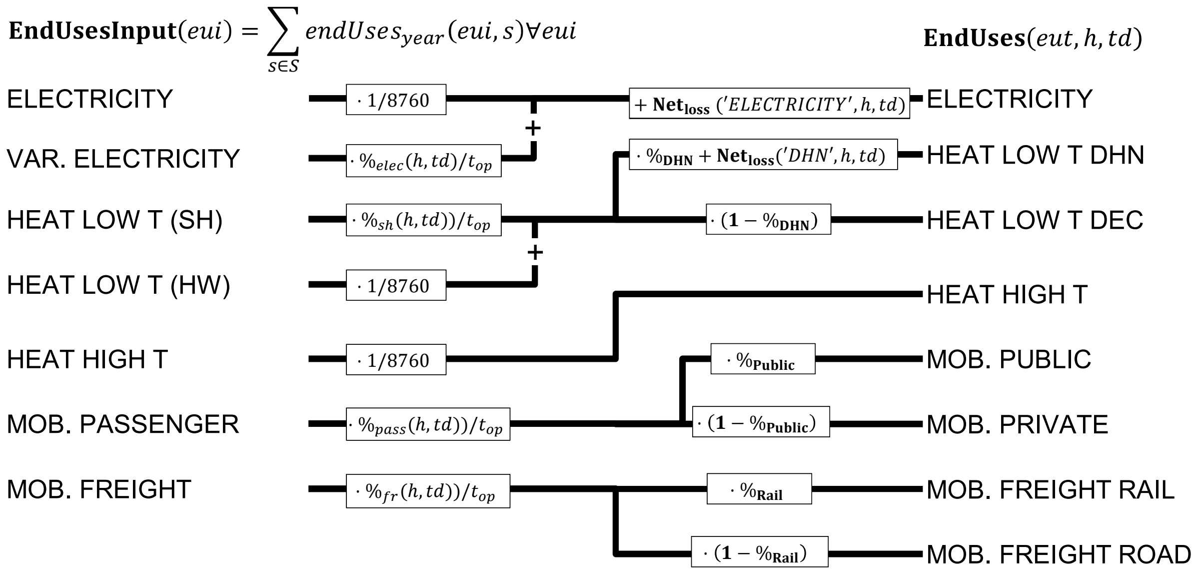


Figure 4: **EndUses** calculation starting from yearly demand model inputs (*endUsesInput*). Adapted from [6]. Abbreviations: space heating (sh), district heating network (DHN), hot water (HW), passenger (pass) and freight (fr).

Figure 4 graphically presents the constraints associated to the hourly end use demand (**EndUses**), e.g. the public mobility demand at time t is equal to the hourly passenger mobility demand times the public mobility share ($\mathbf{\%_{Public}}$).

Electricity end-uses result from the sum of the electricity-only demand, assumed constant throughout the year, and the variable demand of electricity, distributed across the periods according to $\%_{elec}$. Low-temperature heat demand results from the sum of the yearly demand for hot water (HW), evenly shared across the year, and space heating (SH), distributed across the periods according to $\%_{sh}$.

The percentage repartition between centralized (DHN) and decentralized heat demand is defined by the variable $\mathbf{\%_{DHN}}$. High temperature process heat and mobility demand are evenly distributed across the periods. Passenger mobility demand is expressed in passenger-kilometers (pkms), freight transportation demand is in ton-kilometers (tkms). The variables $\mathbf{\%_{Public}}$ and $\mathbf{\%_{Rail}}$ define the penetration of public transportation in passenger mobility and of train in freight, respectively.

Cost, emissions and objective function

The objective Eq. (1) is the minimisation of the total annual cost of the energy system ($\mathbf{C_{tot}}$), defined as the sum of the annualized investment cost of technologies (τ $\mathbf{C_{inv}}$), the operating and maintenance cost of technologies ($\mathbf{C_{maint}}$) and the operating cost of the resources ($\mathbf{C_{op}}$). The total investment cost ($\mathbf{C_{inv}}$) of each technology results from the multiplication of its specific investment cost (c_{inv}) and its installed size ($\mathbf{F}$), the latter defined with respect to the main end-uses output type Eq. (3). $\mathbf{C_{inv}}$ is annualised with the factor τ, calculated based on the interest rate (i_{rate}) and the technology lifetime (*lifetime*) Eq. (2). The total operation and maintenance cost is calculated in the same way Eq. (4). The total cost of the resources is calculated as the sum of the end-use over different periods multiplied by the period duration (t_{op}) and the specific cost of the resource (c_{op}) Eq. (5). Note that, in Eq. (5), summing over the typical days using the set T_H_TD is equivalent to summing over the 8760h of the year.

$$\min \ \mathbf{C_{tot}} = \sum_{j \in TECH} \Big(\tau(j)\mathbf{C_{inv}}(j) + \mathbf{C_{maint}}(j) \Big) + \sum_{i \in RES} \mathbf{C_{op}}(i) \tag{1}$$

$$\text{s.t. } \tau(j) = \frac{i_{rate}(i_{rate}+1)^{lifetime(j)}}{(i_{rate}+1)^{lifetime(j)} - 1} \qquad \forall j \in TECH \tag{2}$$

$$\mathbf{C_{inv}}(j) = c_{inv}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{3}$$

$$\mathbf{C_{maint}}(j) = c_{maint}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{4}$$

$$\mathbf{C_{op}}(i) = \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} c_{op}(i)\mathbf{F_t}(i,h,td)t_{op}(h,td) \qquad \forall i \in RES \tag{5}$$

The global annual greenhouse gas (GHG) emissions are calculated using a life cycle assessment (LCA) approach, i.e. taking into account emissions of technologies and resources "from cradle to grave". For climate change, the natural choice as indicator is the global warming potential (GWP), expressed in ktCO_2-eq./year. In Eq. (6), the total yearly emissions of the system ($\mathbf{GWP_{tot}}$) are defined as the sum of the emissions related to the construction and end-of-life of the energy conversion technologies ($\mathbf{GWP_{constr}}$), allocated to one year based on the technology lifetime (*lifetime*), and the emissions related to resources ($\mathbf{GWP_{op}}$). Similarly to the costs, the total emissions related to the construction of technologies are the product of the specific emissions (gwp_{constr}) and the installed size ($\mathbf{F}$), Eq. (7). The total emissions of resources are the emissions associated to fuels (from cradle to combustion) and imports of electricity (gwp_{op}) multiplied by the period duration (t_{op}) (Eq 8) [3] .

$$\mathbf{GWP_{tot}} = \sum_{j \in TECH} \frac{\mathbf{GWP_{constr}}(j)}{lifetime(j)} + \sum_{i \in RES} \mathbf{GWP_{op}}(i) \tag{6}$$

$$\mathbf{GWP_{constr}}(j) = gwp_{constr}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{7}$$

$$\mathbf{GWP_{op}}(i) = \sum_{t \in T|\{h,td\} \in T\_H\_TD(t)} gwp_{op}(i)\mathbf{F_t}(i,h,td)t_{op}(h,td) \qquad \forall i \in RES \tag{8}$$

System design and operation

The installed capacity of technologies ($\mathbf{F}$) is constrained between upper and lower bounds (f_{max} and f_{min}), Eq. (9). This formulation allows accounting for old technologies still existing in the target year (lower bound), but also for the maximum deployment potential of a technology. As an example, for hydroelectric power plants, f_{min} represents the existing installed capacity (which will still be available in the future), while f_{max} represents the maximum potential .

$$f_{min}(j) \leq \mathbf{F}(j) \leq f_{max}(j) \qquad \forall j \in TECH \tag{9}$$

The operation of resources and technologies in each period is determined by the decision variable $\mathbf{F_t}$. The capacity factor of technologies is conceptually divided into two components: a capacity factor for each period ($c_{p,t}$) depending on resource availability (e.g. renewables) and a yearly capacity factor (c_p) accounting for technology downtime and maintenance. For a given technology, the definition of only one of these two is needed, the other one being fixed to the default value of 1. Eqs. (10) and (11) link the installed size of a technology to its actual use in each period (F_t) via the two capacity factors. The total use of resources is limited by the yearly availability ($avail$), Eq. (12).

$$\mathbf{F_t}(j,h,td) \leq \mathbf{F}(j)c_{p,t}(j,h,td) \qquad \forall j \in TECH, \forall h \in H, \forall td \in TD \tag{10}$$

$$\sum_{t \in T|\{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td)t_{op}(h,td) \leq \mathbf{F}(j)c_p(j) \sum_{t \in T|\{h,td\} \in T\_H\_TD(t)} t_{op}(h,td) \qquad \forall j \in TECH \tag{11}$$

$$\sum_{t \in T|\{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(i,h,td)t_{op}(h,td) \leq avail(i) \qquad \forall i \in RES \tag{12}$$

The matrix f defines for all technologies and resources outputs to (positive) and inputs (negative) layers. Eq. (13) expresses the balance for each layer: all outputs from resources and technologies (including storage) are used to satisfy the EUD or as inputs to other resources and technologies.

$$\sum_{i \in RES \cup TECH \setminus STO} f(i,l)\mathbf{F_t}(i,h,td) + \sum_{j \in STO} \Big(\mathbf{Sto_{out}}(j,l,h,td) - \mathbf{Sto_{in}}(j,l,h,td)\Big) - \mathbf{EndUses}(l,h,td) = 0$$
$$\forall l \in L, \forall h \in H, \forall td \in TD \tag{13}$$

Storage

The storage level ($\mathbf{Sto_{level}}$) at a time step (t) is equal to the storage level at $t-1$ (accounting for the losses in $t-1$), plus the inputs to the storage, minus the output from the storage (accounting

[3] To simplify the reading, we write in this paper $t \in T|\{h,td\} \in T\_H\_TD(t)$. However, this cannot be directly implemented in the code and it requires two additional sets : $HOUR\_OF\_PERIOD(t)$ and $TYPICAL\_DAY\_OF\_PERIOD(t)$. Hence, in the paper we have: $t \in T|\{h,td\} \in T\_H\_TD(t)$, which is equivalent in the code to $t \in T|h \in HOUR\_OF\_PERIOD(t), td \in TYPICAL\_DAY\_OF\_PERIOD(t)$.

for input/output efficiencies (14)). The storage systems which can only be used for short-term (daily) applications are included in the STO DAILY set. For these units, Eq. (15) imposes that the storage level be the same at the end of each typical day. Adding this constraint drastically reduces the computational time. For the other storage technologies, which can also be used for seasonal storage, the capacity is bounded by Eq (16). For these units, the storage behaviour is thus optimized over 8760h, as explained in the methodology Section of the paper.

$$\begin{aligned}
&\mathbf{Sto_{level}}(j,t) = \mathbf{Sto_{level}}(j,t-1)\cdot(1-\%_{sto_{loss}}(j)) + \\
&t_{op}(h,td)\cdot\Big(\sum_{l\in L|\eta_{sto,in}(j,l)>0}\mathbf{Sto_{in}}(j,l,h,td)\eta_{sto,in}(j,l) - \sum_{l\in L|\eta_{sto,out}(j,l)>0}\mathbf{Sto_{out}}(j,l,h,td)/\eta_{sto,out}(j,l)\Big) \\
&\qquad\qquad\forall j\in STO, \forall t\in T|\{h,td\}\in T_H_TD(t)
\end{aligned} \tag{14}$$

$$\mathbf{Sto_{level}}(j,t) = \mathbf{F_t}(j,h,td) \qquad \forall j\in STO\ DAILY, \forall t\in T|\{h,td\}\in T\_H\_TD(t) \tag{15}$$

$$\mathbf{Sto_{level}}(j,t) \leq \mathbf{F}(j) \qquad \forall j\in STO\setminus STO\ DAILY, \forall t\in T \tag{16}$$

Eqs. (17)-(18) force the power input and output to zero if the layer is incompatible [4]. As an example, a PHS will only be linked to the electricity layer (input/output efficiencies > 0). All other efficiencies will be equal to 0, to impede that the PHS exchanges with incompatible layers (e.g. mobility, heat, etc). Eq. (19) limits the power input/output of a storage technology based on its installed capacity (**F**) and three specific characteristics. First, storage availability ($\%_{sto_{avail}}$) is defined as the ratio between the available storage capacity and the total installed capacity (default value is 1). This parameter is required to realistically represent V2G, for which we assume that only a fraction of the fleet can charge/discharge at the same time. Second and third, the charging/discharging time ($t_{sto_{in}}$, $t_{sto_{out}}$), which are the time to complete a full charge/discharge from empty/full storage[5]. As an example, a daily thermal storage can be fully discharged in minimum 4 hours ($t_{sto_{out}} = 4$[h]), and fully charged in maximum 4 hours ($t_{sto_{in}} = 4$[h]).

$$\mathbf{Sto_{in}}(j,l,h,td)\cdot\Big(\lceil\eta_{sto,in}(j,l)\rceil - 1\Big) = 0 \qquad \forall j\in STO, \forall l\in L, \forall h\in H, \forall td\in TD \tag{17}$$

$$\mathbf{Sto_{out}}(j,l,h,td)\cdot\Big(\lceil\eta_{sto,out}(j,l)\rceil - 1\Big) = 0 \qquad \forall j\in STO, \forall l\in L, \forall h\in H, \forall td\in TD \tag{18}$$

$$\begin{aligned}
&\Big(\mathbf{Sto_{in}}(j,l,h,td)t_{sto_{in}}(j) + \mathbf{Sto_{out}}(j,l,h,td)t_{sto_{out}}(j)\Big) \leq \mathbf{F}(j)\%_{sto_{avail}}(j) \\
&\qquad\qquad\forall j\in STO, \forall l\in L, \forall h\in H, \forall td\in TD
\end{aligned} \tag{19}$$

Infrastructure

Eq. (20) calculates network losses as a share ($\%_{net_{loss}}$) of the total energy transferred through the network. As an example, losses in the electricity grid are estimated to be 7% of the energy transferred[6]. Eqs. (21)-(23) define the extra investment for networks. Integration of inter-

[4] In the code, these equations are implemented with a *if-then* statement.

[5] In this linear formulation, storage technologies can charge and discharge at the same time. On the one hand, this avoids the need of integer variables (see 1.3.2); on the other hand, it has no physical meaning. However, in a cost minimization problem, the cheapest solution identified by the solver will always choose to either charge or discharge at any given t, as long as cost and efficiencies are defined. Hence, we recommend to always verify numerically the fact that only storage inputs or outputs are activated at each t, as we do in all our implementations.

[6] This is the ratio between the losses in the grid and the total annual electricity production in Switzerland in 2015 [6, 7].

mittent renewable energies (iRE) implies an additional investment costs for the electricity grid ($c_{grid,extra}$). As an example, the needed investments are expected to be 2.5 billions CHF_{2015} for the high voltage grid and 9.4 billions CHF_{2015} for the medium and low voltage grid[7]. Eq. (22) links the size of DHN to the total size of the installed centralized energy conversion technologies. The power-to-gas storage data is implemented as in Al-musleh et al. [9]. It is implemented in the model with two conversion units and a liquified natural gas (LNG) storage tank. $PowerToGas_{in}$ converts electricity to LNG, $PowerToGas_{out}$ converts LNG back to electricity. The investment cost is associated to the PowerToGas unit, whose size is the maximum size of the two conversion units, Eq. (23) here displayed in a compact non-linear formulation[8].

$$\mathbf{Net_{loss}}(eut,h,td) = \Big(\sum_{i \in RES \cup TECH \setminus STO | f(i,eut)>0} f(i,eut)\mathbf{F_t}(i,h,td)\Big)\%_{net_{loss}}(eut) \quad \forall eut = EUT, \forall h \in H, \forall td \in TD \quad (20)$$

$$\mathbf{F}(Grid) = \frac{c_{grid,extra}}{c_{inv}(Grid)} \frac{\mathbf{F}(Wind) + \mathbf{F}(PV)}{f_{max}(Wind) + f_{max}(PV)} \quad (21)$$

$$\mathbf{F}(DHN) = \sum_{j \in TECH\ OF\ EUT(HeatLowTDHN)} \mathbf{F}(j) \quad (22)$$

$$\mathbf{F}(PowerToGas) = \max(\mathbf{F}(PowerToGas_{in}), \mathbf{F}(PowerToGas_{out})) \quad (23)$$

Additional Constraints

Nuclear power plants are assumed to have no power variation over the year (24). If needed, this equation can be replicated for all other technologies for which a constant operation over the year is desired.

$$\mathbf{F_t}(Nuclear,h,td) = \mathbf{P_{Nuc}} \quad \forall h \in H, \forall td \in TD \quad (24)$$

Eq. (25) imposes that the share of the different technologies for mobility ($\mathbf{\%_{MobPass}}$) be the same at each time step. In other words, if 20% of the mobility is supplied by train, this share remains constant in the morning or the afternoon. The addition of this constraint is motivated by the fact that the investment cost of passenger and freight transport technologies is not accounted for in the model ($c_{inv} = 0$ for these technologies).

$$\mathbf{F_t}(j,h,td) = \mathbf{\%_{MobPass}}(j) \sum_{l \in EUT\ of\ EUC(MobPass)} \mathbf{EndUses}(l,h,td) \quad \forall j \in TECH\ OF\ EUC(MobPass), \forall h \in H, \forall td \in TD \quad (25)$$

Decentralised heat production:

Thermal solar is implemented as a decentralized technology. It is always installed together with another decentralized technology, which serves as backup to compensate for the intermittency of solar thermal. Thus, we define the total installed capacity of solar thermal $\mathbf{F}(Dec_{Solar})$ as the sum of $\mathbf{F_{sol}}(j)$ (27), where $\mathbf{F_{sol}}(j)$ is the solar thermal capacity associated to the backup

[7]These values correspond to the scenario 3 in [8].

[8]All equations expressed in a compact non-linear form in this section (Eqs. 23, 25, 28 and 35) can be linearized; their linearization is given in Appendix 1.3.2

technology j. Eq. (26) links the installed size of each solar thermal capacity ($\mathbf{F_{sol}}(j)$) to its actual production ($\mathbf{F_{t_{sol}}}(j,h,td)$) via the solar capacity factor ($c_{p,t}(Dec_{Solar},h,td)$).

$$\mathbf{F_{t_{sol}}}(j,h,td) \leq \mathbf{F_{sol}}(j) c_{p,t}(Dec_{Solar},h,td)$$
$$\forall j \in TECH\ OF\ EUT(HeatLowTDec) \setminus \{Dec_{Solar}\}, \forall h \in H, \forall td \in TD \quad (26)$$

$$\mathbf{F}(Dec_{Solar}) = \sum_{j \in TECH\ OF\ EUT(HeatLowTDec) \setminus \{Dec_{Solar}\}} \mathbf{F_{sol}}(j) \quad (27)$$

A thermal storage i is defined for each decentralised heating technology j, to which it is related via the set *TS OF DEC TECH*, i.e. *i=TS OF DEC TECH(j)*. Each thermal storage i can store heat from its technology j and the associated thermal solar $\mathbf{F_{sol}}(j)$. Similarly to the passenger mobility, Eq. (28) makes the model more realistic by defining the operating strategy for decentralized heating. In fact, in the model we represent decentralized heat in an aggregated form; however, in a real case, residential heat cannot be aggregated obviously. A house heated by a decentralised gas boiler and solar thermal panels should not be able to be heated by the electrical heat pump and thermal storage of the neighbours, and vice-versa. Hence, Eq. (28) imposes that the use of each technology ($\mathbf{F_t}(j,h,td)$), plus its associated thermal solar ($\mathbf{F_{t_{sol}}}(j,h,td)$) plus its associated storage outputs ($\mathbf{Sto_{out}}(i,l,h,td)$) minus its associated storage inputs ($\mathbf{Sto_{in}}(i,l,h,td)$) should be a constant share ($\mathbf{\%_{HeatDec}}(j)$) of the decentralised heat demand ($\mathbf{EndUses}(HeatLowT,h,td)$). Figure 5 shows, through an example with two technologies (a gas boiler and a heat pump (HP)), how decentralised thermal storage and thermal solar are implemented.

$$\mathbf{F_t}(j,h,td) + \mathbf{F_{t_{sol}}}(j,h,td) + \sum_{l \in L} \Big(\mathbf{Sto_{out}}(i,l,h,td) - \mathbf{Sto_{in}}(i,l,h,td)\Big)$$
$$= \mathbf{\%_{HeatDec}}(j)\mathbf{EndUses}(HeatLowT,h,td)$$
$$\forall j \in TECH\ OF\ EUT(HeatLowTDec) \setminus \{Dec_{Solar}\}, i \in TS\ OF\ DEC\ TECH(j), \forall h \in H, \forall td \in TD \quad (28)$$

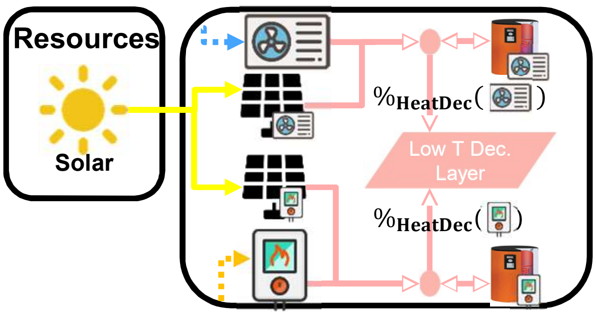


Figure 5: Illustrative example of a decentralised heating layer with thermal storage, solar thermal and two conventional production technologies, gas boilers and electrical HP. In this case, Eq. 28 applied to the electrical HPs becomes the equality between the two following terms: left term is the heat produced by: the eHPs ($\mathbf{F_t}('eHPs')$), the solar panel associated to the eHPs ($\mathbf{F_{t_{sol}}}('eHPs')$) and the storage associated to the eHPs; right term is the product between the share of decentralised heat supplied by eHPs ($\mathbf{\%_{HeatDec}}$*('eHPs')*) and heat low temperature decentralised demand ($\mathbf{EndUses}(HeatLowT,h,td)$).

Hydroelectric dams:

Hydroelectric dams are implemented here as the combination of two components: a storage unit (the reservoir, or dam storage (*DamSto*)) and a power production unit (*HydroDam*). It has to be noted that, in this implementation, we differentiate between PHS and the storage unit with river inflow *DamSto*. *PHS* has a lower and upper reservoir without inlet source; *DamSto* has an inlet source, i.e. a river inflow, but cannot pump water from the lower reservoir. The power production technology *HydroDam* accounts for all the dam hydroelectric infrastructure cost and emissions. Eqs. (29)-(31) regulate the reservoir (*DamSto*) based on the production (*HydroDam*). Eq. 29 linearly relates the reservoir size with the power plant size ($\mathbf{F}(HydroDam)$). Eq. 30 imposes the storage input power ($\mathbf{Sto_{in}}$) to be equal to the water inflow term ($\mathbf{F_t}$ $(HydroDam, h, td)$). This latter is constrained by Eq. 10 and represents the water inflow in the dam ($\mathbf{Sto_{in}}$). Eq. (31) ensures that the storage output ($\mathbf{Sto_{out}}$) be lower than the installed capacity ($\mathbf{F}$ $(HydroDam)$). Figure 6 shows how the reservoir (*DamSto*) and the power unit (*HydroDam*) are implemented.

$$\mathbf{F}(DamSto) \leq f_{min}(DamSto) + \\ (f_{max}(DamSto) - f_{min}(DamSto)) \frac{\mathbf{F}(HydroDam) - f_{min}(HydroDam)}{f_{max}(HydroDam) - f_{min}(HydroDam)} \tag{29}$$

$$\mathbf{Sto_{in}}(DamSto, Elec, h, td) = \mathbf{F_t}(HydroDam, h, td) \qquad \forall h \in H, \forall td \in TD \tag{30}$$

$$\mathbf{Sto_{out}}(DamSto, Elec, h, td) \leq \mathbf{F}(HydroDam) \qquad \forall h \in H, \forall td \in TD \tag{31}$$

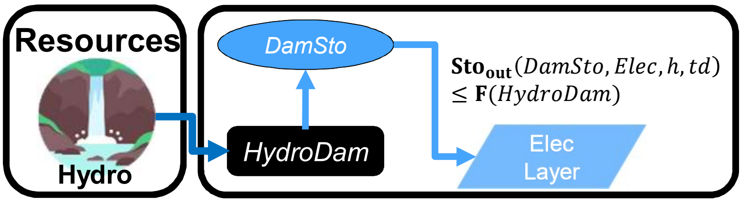


Figure 6: Visual representation of hydro dams implementation in the model. The storage (*DamSto*) is filled by river inflows and can produce electricity through the *HydroDam* technology.

Vehicle-to-grid:

Vehicle-to-grid dynamics are included in the model via the *V2G* set. For each vehicle $j \in$ *V2G*, a battery i ($i \in$ *EVs_BATT*) is associated using the set *EVs_BATT OF V2G* ($i \in$ *EVs_BATT OF V2G*(j)). Each type j of *V2G* has a different size of battery per car ($ev_{Batt,size}(j)$), e.g. the first generation battery of the Nissan Leaf (ZE0) has a capacity of 24 kWh[9]. To estimate the number of vehicles of a given technology, we use the share of mobility covered supplied by this technology ($\mathbf{\%_{MobPass}}$) and the number of cars required if all the mobility was covered with private cars $n_{car,max}$[10]. Thus, the energy that can be stored in batteries $\mathbf{F}(i)$ of $V2G(j)$ is

[9]from `https://en.wikipedia.org/wiki/Nissan_Leaf`, consulted on 29-01-2019

[10]This parameter is hard to find. However, its value is only used to assess the overall size of electric vehicles (EVs) batteries. These batteries are used for V2G and smart charging. It has been verified that a variation in this value has a almost no impact on the results.

the product of the maximum number of cars ($n_{car,max}$) mutliplied by the share of the mobility covered by the type of vehicle j ($\boldsymbol{\%_{MobPass}}(j)$) and the size of battery per car ($ev_{Batt,size}(j)$) (32). As an example, if all the drivers of Switzerland (5.8 millions [10]) owned a car and 5% of the mobility was supplied by Nissan Leaf (ZE0), then the energy that could be stored by this technology would be 6.76 GWh.

Eq. (33) forces batteries of electric vehicle to supply, at least, the energy required by each associated electric vehicle technology. This lower bound is not an equality; in fact, according to the V2G concept, batteries can also be used to support the grid. Figure 7 shows through an example with only battery electric vehicles (BEVs) how Eq. (33) simplifies the implementation of V2G. In this illustration, a battery technology is associated to a BEV. The battery can either supply the BEV needs or restore electricity to the grid.

$$\mathbf{F}(i) = n_{car,max} \boldsymbol{\%_{MobPass}}(j) ev_{Batt,size}(j) \qquad \forall j \in V2G, i \in EVs\_BATT\ OF\ V2G(j) \quad (32)$$

$$\mathbf{Sto_{out}}(i, Elec, h, td) \geq -f(j, Elec)\mathbf{F_t}(j, h, td)$$
$$\forall j \in V2G, \forall i \in EVs\_BATT\ OF\ V2G(j), \forall h \in H, td \in TD \quad (33)$$

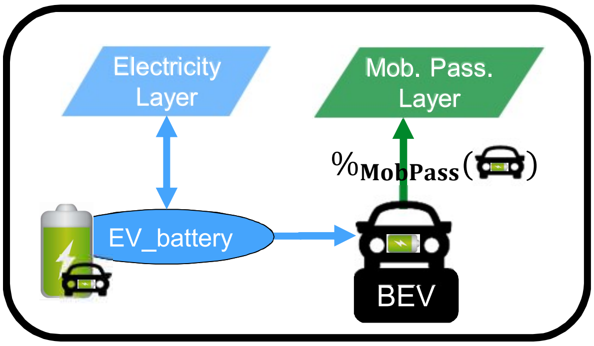


Figure 7: Illustrativee example of a V2G implementation. The battery can interact with the electricity layer. The V2G takes the electricity from the battery to provide a constant share ($\boldsymbol{\%_{MobPass}}$) of the passenger mobility layer (*Mob. Pass.*).

Peak demand:

Finally, Eqs. (34)-(35) constrain the installed capacity of low temperature heat supply. Based on the selected typical days (TDs), the ratio between the yearly peak demand and the TDs peak demand is defined for space heating ($\%_{Peak_{sh}}$). Eq. (34) imposes that the installed capacity for decentralised technologies covers the real peak over the year. Similarly, Eq. (35) forces the centralised heating system to have a supply capacity (production plus storage) higher than the peak demand.

$$\mathbf{F}(j) \geq \%_{Peak_{sh}} \max_{h \in H, td \in TD} \{\mathbf{F_t}(j, h, td)\}$$
$$\forall j \in TECH\ OF\ EUT\ (HeatLowTDEC) \setminus \{Dec_{Solar}\} \quad (34)$$

$$\sum_{j \in TECH\ OF\ EUT(HeatLowTDHN), i \in STO\ OF\ EUT(HeatLowTDHN)} \Big(\mathbf{F}(j) + \mathbf{F}(i)/t_{sto_{out}}(i, HeatLowTDHN)\Big)$$

$$\geq \%_{Peak_{sh}} \max_{h \in H, td \in TD} \left\{ \mathbf{EndUses}(HeatLowTDHN, h, td) \right\} \tag{35}$$

1.3.1 Adaptation for the case study

Additional constraints are required to implement the scenarios and the Swiss hydroelectric power plants. Scenarios require four additional constraints (36-39) to impose a limit on the GWP emissions, the minimum share of renewable energies (RE) primary energy, the relative shares of some technologies, such as gasoline cars in the private mobility and the cost of energy efficiency measures. Due to the high penetration of hydropower in Switzerland and the good availability of data, the hydro potential has been split into old and new hydro plants and that changes three constraints (40-42). Eq. 36 imposes a limit on the GWP (gwp_{limit}). Eq. 37 fixes the minimum renewable primary energy share. Eq. 38 is complementary to Eq. 9, as it expresses the minimum ($f_{min,\%}$) and maximum ($f_{max,\%}$) yearly output shares of each technology for each type of EUD. In fact, for a given technology, assigning a relative share (e.g. boilers providing at least a given percent of the total heat demand) is more intuitive and close to the energy planning practice than limiting its installed size. $f_{min,\%}$ and $f_{max,\%}$ are fixed to 0 and 1, respectively, unless otherwise indicated. Eq. 39 imposes the cost of energy efficiency. The EUD is based on a scenario detailed in Section 2.1 and has a lower energy demand than the "business as usual" scenario, which has the highest energy demand. Hence, the energy efficiency cost represents the difference between the implemented scenario and the "business as usual" scenario. As explained later in 2.7.4, the implemented scenario has the lowest EUD, in counterpart, this scenario requires to invest the maximum in efficiency measures.

$$\mathbf{GWP_{tot}} \leq gwp_{limit} \tag{36}$$

$$\sum_{j \in \text{RES}_{\text{re}}, t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \geq re_{\text{share}} \sum_{j \in RES, t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \tag{37}$$

$$f_{min,\%}(j) \sum_{j' \in TECH\ OF\ EUT(eut), t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j',h,td) \cdot t_{op}(h,td) \leq \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \leq f_{max,\%}(j) \sum_{j'' \in TECH\ OF\ EUT(eut), t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j'',h,td) \cdot t_{op}(h,td)$$
$$\forall eut \in EUT, \forall j \in TECH\ OF\ EUT(eut) \tag{38}$$

$$\mathbf{F}(Efficiency) = \frac{1}{1 + i_{rate}} \tag{39}$$

Due to the high penetration of hydropower in Switzerland and the good availability of data, the hydro potential has been split into old and new hydro plants. The old power plants have a fixed capacity and a known cost. Compared to the existing plants, the new power plants have a different price [6]. As a consequence, Eqs. (29-31) are modified to integrate the potential of new hydro dams and became, respectively, Eqs (40-42).

$$\mathbf{F}(DamSto) \leq f_{min}(DamSto) + (f_{max}(DamSto) - f_{min}(DamSto)) \frac{\mathbf{F}(NewHydroDam) - f_{min}(NewHydroDam)}{f_{max}(NewHydroDam) - f_{min}(NewHydroDam)} \tag{40}$$

$$\mathbf{Sto_{in}}(DamSto, Elec, h, td) = \mathbf{F_t}(HydroDam, h, td) + \mathbf{F_t}(NewHydroDam, h, td) \quad \forall h \in H, \forall td \in TD \tag{41}$$

$$\mathbf{Sto_{out}}(DamSto, Elec, h, td) \leq \mathbf{F}(HydroDam) + \mathbf{F}(NewHydroDam)$$

$$\forall h \in H, \forall td \in TD \quad (42)$$

1.3.2 Linearisation of integer variables

Equations (25 and 28) multiply two variables among which **EndUses**. The latter is a dependent variable depending only on parameters, and thus it can be rewritten as a sum and products of parameters as shown in Figure 4.

Compared to the previous version of EnergyScope reported by Moret [6], the integer variables have been removed. In [6], they had the following use: (i) forcing the number of technologies to be an integer multiple of a reference size (e.g. one could only install 0.5, 1, 1.5, etc GW of CCGT if reference size is 0.5 GW); (ii) forcing that storage cannot charge and discharge at the same time; (iii) defining backup decentralised production technologies for thermal solar.

These variables were removed to reduce the computational time. As a consequence, (i) we accepted to have continuous size for installed capacities, such as 732 MW of CCGT; (ii) we systematically verify during the post treatment that a storage technology is not charging and discharging at the same time, which removes the need of using a binary variables. This change was also required to implement V2G, which can both charge and discharge. Complementarily, Eq. 19 verifies that the power charging and discharging are not higher than the maximum capacity. For example, assuming a case with 100 electric cars with a battery of 10kWh each, with an energy to power ratio of 10 (charging) and 5 (discharging) and with 20% of the cars are available to drive or charge. In this case, the charge and discharge powers are limited to a maximum of 20 or 40 kW, respectively, or a mix of the two. Finally, (iii) as illustrated in Section 1.3, the thermal solar implementation has been improved; the new formulation is more realistic and does not require the use of binary/integer variables.

2 Swiss energy system data

This appendix reports the input data for the application of the LP modeling framework to the case study of Switzerland in the years 2035 and 2011, the latter used for model verification. The resources and technologies in Figure 6 of the paper are characterized in terms of energy and mass balances, cost (operating and investment), and environmental impact (global warming potential (GWP)).

For GHG emissions, LCA data are taken from the Ecoinvent database v3.2[11] [11] using the "allocation at the point of substitution" method. GWP is assessed with the "GWP100a - IPCC2013" indicator. For technologies, the GWP impact accounts for the technology construction; for resources, it accounts for extraction, transportation and combustion.

For the cost, the reported data are the nominal values for Switzerland in the year 2035. All costs are expressed in *real*[12] Swiss Francs for the year 2015 ($_{2015}$). All cost data used in the model originally expressed in other currencies or referring to another year are converted to CHF_{2015} to offer a coherent comparison. The method used for the conversion is illustrated by Eq. 43.

$$c_{inv}[\text{CHF}_{2015}] = c_{inv}[C_y] \cdot \frac{\text{USD}_y}{C_y} \cdot \frac{\text{CEPCI}_{2015}\ [\text{USD}_{2015}]}{\text{CEPCI}_y\ [\text{USD}_y]} \cdot \frac{\text{CHF}_{2015}}{\text{USD}_{2015}} \tag{43}$$

[11] The database is consulted online: `http://www.ecoinvent.org`

[12] *Real* values are expressed at the net of inflation. They differ from *nominal* values, which are the actual prices in a given year, accounting for inflation.

Table 5: CEPCI values [12]

Year	**CEPCI**
1982	285.8
1990	357.6
1991	362.3
1992	367.0
1993	371.7
1994	376.4
1995	381.1
1996	381.7
1997	386.5
1998	389.5
1999	390.6
2000	394.1
2001	394.3
2002	395.6
2003	402.0
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8
2011	585.7
2012	584.6
2013	567.3
2014	576.1
2015	556.3

Where C and y are the currency and the year in which the original cost data are expressed, respectively, is the symbol of American Dollars and the Chemical Engineering's Plant Cost Index (CEPCI) [12] is an index taking into account the evolution of the equipment cost (values reported in Table 5). As an example, if the cost data are originally in EUR_{2010}, they are first converted to USD_{2010}, then brought to USD_{2015} taking into account the evolution of the equipment cost (by using the CEPCI), and finally converted to CHF_{2015}. The intermediate conversion to USD is motivated by the fact that the CEPCI is expressed in *nominal* USD. Although this conversion method is originally defined for technology-related costs, in this thesis as a simplification it used also for the cost of resources.

2.1 Energy demand

The EUD for heating, electricity and mobility in 2035 is calculated from the data in [13] for the "Politisches Massnahmenpaket" ("PMF", Political Measures of the Federal Council) scenario in the year 2035.

2.1.1 Heating

The EUD for SH in households is calculated as the product of the number of inhabitants in Switzerland, the *per capita* living space and the annual specific heating requirement (Table 6). The EUD for HW in households is the only heating requirement which is not calculated based on the "PMF" scenario. It is calculated assuming a *per capita* daily HW consumption of 50 L/day/inhabitant and a temperature increase of 40 °C [14].

Table 6: Data for the calculation of the end use energy demand in the households sector.

	"PMF" scenario in 2035 [13]
Population [10^6 people]	8.89
Living space [m^2/person]	67
Specific heating requirement [kWh/m^2/y]	49.5
HW consumption [L/day/person]	50 [14]
Temperature increase for HW production [°C]	40

Table 7 reports input data and calculated values for the heating EUD in the different sectors. The calculation of the end-use heating demand in the industry and services sectors starts from the FEC data by type of heat usage, available in Table 9-18 and Table 9-23 in [13]. The FEC values reported in [13] are the sum of the fuel consumption in boilers, the electricity consumption for direct electric heating and for HPs, and the ambient heat used by the latter. The EUD for heating in the industry and service sectors accounts for the heat supplied by the HPs (equal to the sum of the ambient heat and their electricity consumption), the heat produced by direct electric heating systems (equal to their electricity consumption) and the heat supplied by boilers (which is estimated assuming a 90% efficiency).
For both sectors, first the FEC is shared among the different technologies, then it is proportionally divided among space heating, hot water and process heating. The ambient heat consumption is obtained from tables 9-21 and 9-27 in [13]. The electricity consumed by the heat pumps using the reported ambient heat is calculated using a coefficient of performance (COP) of 3.7. The COP is based on the ambient heat and electricity consumption of the heat pumps in the household sector in 2035 (table 9-7 and 9-10 in [13]). The electricity consumption for direct electric heating is computed as the sum of the electricity consumption for space heating, hot water and process heating (Tables 9-19 and 9-24 in [13]) minus the calculated electricity consumption of the heat pumps. The use of direct electric heating systems is divided between space heating, hot water and process heating proportionally to the FEC of each end-use type. It is assumed that heat pumps are not used for the high temperature EUD in the industry sector. Thus, the use of heat pumps is shared between space heating and hot water.
In the model, there is a repartition between low temperature and high temperature heating EUD. The first one includes EUD for space heating and hot water. The second one is the EUD for process heating. The services sector has only low temperature heating EUD, while the industry sector has both.

Process heating and HW demand are considered constant over the year, whereas SH demand is shared over the year according to $\%_{heating}$, which is illustrated in Figure 8 (based on the data presented in Appendix D of [15]). Another illustration is Table 8 that summarises these data by aggregating the monthly heat demands.

Table 7: FEC and EUD in the household, industry and service sectors.

		"PMF" scenario in 2035 [13]			
	EUD type	**Technology/Source**	**Households** [GWh/y]	**Industry** [GWh/y]	**Services** [GWh/y]
FEC	Space heating			5361	15861
	Hot water			1389	3556
	Process heating			20722	0
FEC		Fuels[a]		22211	16361
		Ambient heat		244	1750
		Elec. heat pumps		92	653
		Elec. direct heating		4925	653
FEC[a]	Space heating	Fuels		4133	13365
		Ambient heat		194	1430
		Elec. heat pumps		73	533
		Elec. direct heating		961	533
	Hot water	Fuels		1071	2996
		Ambient heat		50	320
		Elec. heat pumps		19	120
		Elec. direct heating		249	120
	Process heating	Fuels		17007	0
		Ambient heat		0	0
		Elec. heat pumps		0	0
		Elec. direct heating		3715	0
EUD[a]	Space heating		29489	4948	14525
	Hot water		7538	1282	3256
	Process heating		0	19021	0
EUD[a]	Low temperature		37027	6230	17781
	High temperature		0	19021	0

[a] Calculated values.

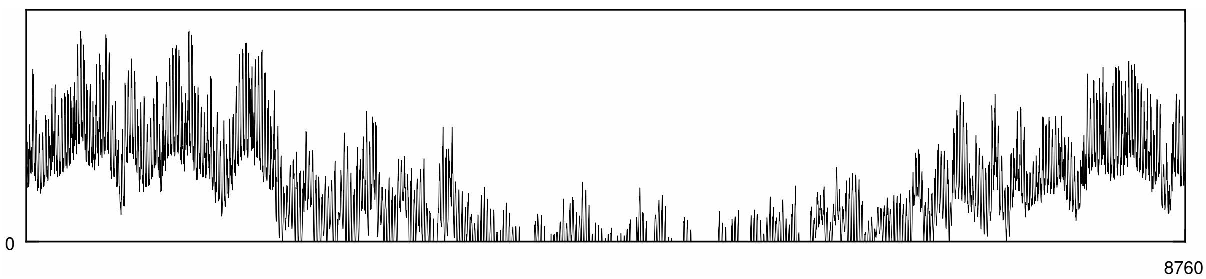


Figure 8: Normalised space heating time series over the year.

Table 8: Aggregated monthly distribution factors for SH demand ($\%_{heating}$) and varying electricity demand ($\%_{elec}$).

	Yearly share (adding up to 1) of space heating and electricity [-]											
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
$\%_{heating}$	0.179	0.168	0.138	0.064	0.036	0.010	0.007	0.010	0.029	0.078	0.111	0.170
$\%_{elec}$	0.091	0.081	0.089	0.079	0.081	0.079	0.078	0.080	0.082	0.084	0.086	0.089

2.1.2 Electricity

The values in Table 9 list the electricity demand that is not related to heating for the three sectors in 2035. The values are taken from tables 9-11, 9-13, 9-15, 9-19 and 9-24 in [13]. The varying demand of electricity is shared over the year according to $\%_{elec}$, which is represented in Figure 9 (based on the data presented in Appendix D of [15]). Table 8 summarises these data by aggregating the monthly electricity demands.

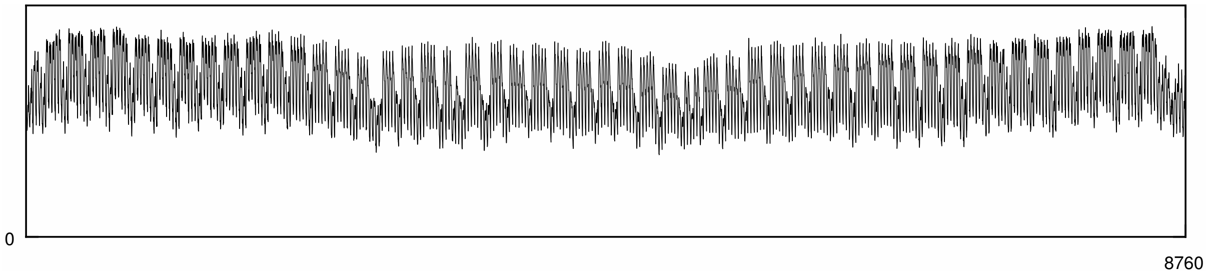


Figure 9: Normalised electricity time series over the year.

Table 9: Electricity demand not related to heating by sector.

	"PMF" scenario in 2035 [13]	
	Lighting [GWh]	**Others** [GWh]
Households	425	10848
Industry	1264	10444
Services	3805	15026

2.1.3 Mobility

The annual passenger transport demand in Switzerland for 2035 is expected to be 146e09 passenger-kilometers (pkms) [13]. Passenger transport demand is divided between public and private transport. The lower ($\%_{public,min}$) and upper bounds ($\%_{public,max}$) for the use of public transport are 30% and 50% of the annual passenger transport demand, respectively. The passenger mobility demand is shared over the day according to $\%_{pass}$. We assume a constant passenger mobility demand for every day of the year. This latter is represented in Figure 10 (data from Figure 12 of [16]).

The annual freight transport demand in Switzerland for 2035 is expected to be 40.0e09 ton-kilometers (tkms). It is shared between road (trucks) and rail (train) freight transport [13].

The lower ($\%_{rail,min}$) and upper bounds ($\%_{rail,max}$) for the use of freight trains are 40% and 60% of the annual freight transport demand, respectively.

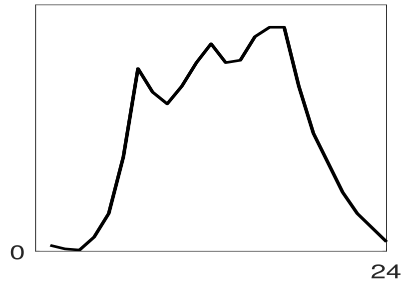


Figure 10: Normalised passenger mobility time series over a day. We assume a similar passenger mobility demand over the days of the year.

2.2 Electricity production and hydro dams

2.2.1 Renewables

Table 10: Renewable electricity production technologies

	$\boldsymbol{f_{ref}}$ [GW]	$\boldsymbol{c_{inv}}$ [CHF_{2015}/kW_e]	$\boldsymbol{c_{maint}}$ [$CHF_{2015}/kW_e/y$]	$\boldsymbol{gwp_{constr}}$ [$kgCO_2$-eq./kW_e]	**Lifetime** [y]	$\boldsymbol{c_p}$ [%]	$\boldsymbol{f_{min}}$ [GW]	$\boldsymbol{f_{max}}$ [GW]
Solar PV	3.00e-06	1000[a]	15.9[a]	2081 [11]	25 [18]	11.3[b]	0	25[c]
Wind Turbine	3.00e-03	1466[d]	23.9[d]	622.9 [11]	20 [22]	23.0[e]	0	5.30[f]
Existing Hydro Dam	8.08	4828 [27]	24.1 [27]	1693 [11]	40 [27]	23.4	8.08 [28]	8.08 [28]
New Hydro Dam[g]	1.00e-3	3437	2.89				0	0.44
Existing Hydro River	3.80	5387 [27]	53.9 [27]	1263 [11]	40 [27]	48.4	3.80 [28]	3.80 [28]
New Hydro River[g]	1.00e-04	5919	76.3				0	0.85
Geothermal[h]	7.6e-03	11464	465	2.493e01 [11]	30	86 [29]	0	0.70[i]

[a] Investment cost based on expert opinion (Christophe Ballif, EPFL, April 2017), operation and maintenance (O&M) cost scaled proportionally based on IEA data. The IEA [17] indicates a c_{inv} of 1557 CHF_{2015}/kW_e and a c_{maint} of 24.7 CHF_{2015}/kW_e for a residential system in 2035.

[b] Cumulated PV installed capacity in Switzerland reached about 0.44 GW in 2012, of which 0.226 GW deployed in the same year. In the same year the overall PV production has been 320.29 GWh [19]. Therefore, assuming a constant growth rate for the installed capacity, the average capacity factor is 0.113.

[c] In Switzerland the available/adequate surface for solar panels deployment is estimated to be 140 km^2 for roofs and 55 km^2 for façades [20]. Assuming that 40% of this surface is used for the installation of PV panels with a 25% [21] electrical efficiency, then the photovoltaic potential is 25 TWh/y.

[d] Onshore wind turbines in 2035 [17].

[e] The actual capacity factor is approximately 0.19 in Switzerland [23]. The International Energy Agency (IEA) states that "turbine design advancement in ten years allows for significant increase in capacity factors" [24]. The new low wind speed turbines are expected to have a capacity factor of 0.33 for an average annual wind speed of 5.5 m/s at 50 m height [24]. In Switzerland, there are several possible locations where average annual wind speed reaches 5.5 m/s [25]. Considering these factors and adopting a conservative approach, the selected value for 2035 is chosen to be 0.23.

[f] The maximum electricity production potential is estimated to be 10.7 TWh/y (potential that can be accepted by the Swiss population) [26].

[g] See the dedicated section.

[h] Organic Rankine cycle (ORC) cycle at 6 km depth for electricity production.

[i] 4.4 TWh/y are estimated in [13] for the year 2050.

Data for the considered renewable electricity production technologies are listed in Table 10. In Table 10, the yearly capacity factor (c_p) is reported. As described in the methodology Section of the paper, for seasonal renewables the capacity factor $c_{p,t}$ is defined for each time period. These capacity factors are represented in Figure 11. For these technologies, c_p is the average of $c_{p,t}$. The hourly values are aggregated per month and reported in Table 11. For all the other electricity supply technologies (renewable and non-renewable), $c_{p,t}$ is equal to the default value of 1.

Table 11: Aggregated monthly electricity production share from renewable energy sources.

	Monthly electricity production share ($dist_t$) [-]											
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Solar PV	0.030	0.043	0.099	0.092	0.128	0.123	0.132	0.137	0.094	0.062	0.039	0.020
Wind	0.118	0.070	0.074	0.101	0.091	0.074	0.078	0.062	0.085	0.069	0.076	0.104
Hydro Dam	0.029	0.014	0.026	0.056	0.145	0.199	0.177	0.134	0.084	0.064	0.045	0.027
Hyro River	0.060	0.041	0.051	0.069	0.121	0.125	0.125	0.113	0.092	0.076	0.072	0.056

2.2.1.1 Hydro power in Switzerland The projected capacity factors for hydroelectric run-of-river plants and dams are calculated based on the data in Table 12. A decrease in the electricity production is expected in the next years due to the application of the LEaux law [30]. The law defines the minimum flow rates for rivers. In order to respect them, during some periods of the year it may be necessary to stop the power plants, i.e. letting the water flow bypassing the turbines. This will have as a consequence a decrease in the annual electricity production. The decrease in electricity production is estimated to be 1400 GWh/y [30]. In the model, the LEaux production penalty is shared between run-of-river plans and dams proportionally to their net yearly electricity production. The net electricity production is the total electricity production minus the electricity consumed for the pumping in the dams.

Table 12: Data for the calculation of the future capacity factors for hydro run-of-river and dams.

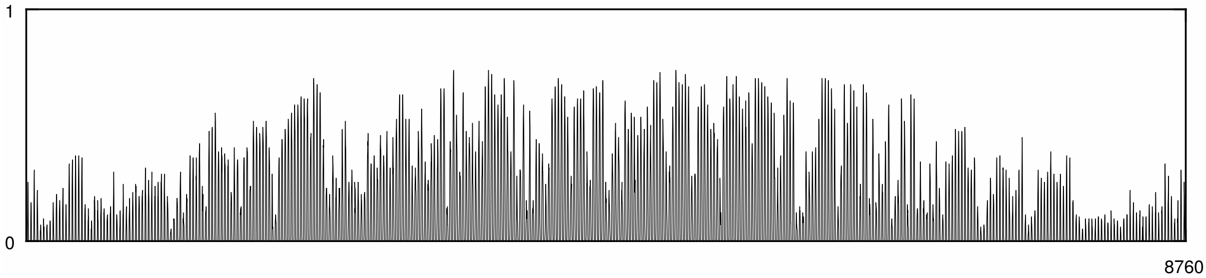
	Hydro river	**Hydro dam**
Net electricity production (2012) [GWh] [28]	16981	17297
Installed power (2012) [GW] [28]	3.84	8.08
LEaux effect [GWh] [30]	-686	-714
c_p **[%]**	48.4	23.4

The Swiss Federal Office of Energy (SFOE) has evaluated the development potential for hydroelectricty [30]. The results of the study are presented in Table 13.

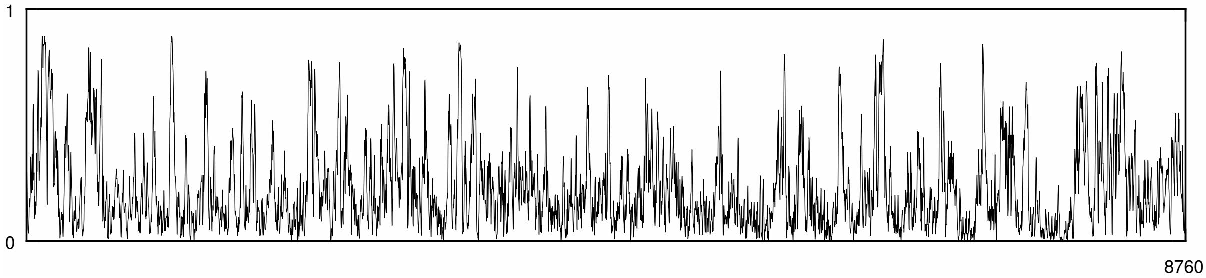
Forecasts in [13] for the year 2050 are based on the development potential under optimized conditions in Table 13. This potential is distributed between hydro river and hydro dam (Table 14).

In the model, this additional potential is added to the 2012 net electricity production to obtain the electricity production potential of Swiss hydroelectric power plants in 2050 (Table 15). The small hydro potential is attributed to the hydro run-of-river technology as additional capacity. The values in Table 15 for 2050 already include the decrease in production caused by the LEaux law.

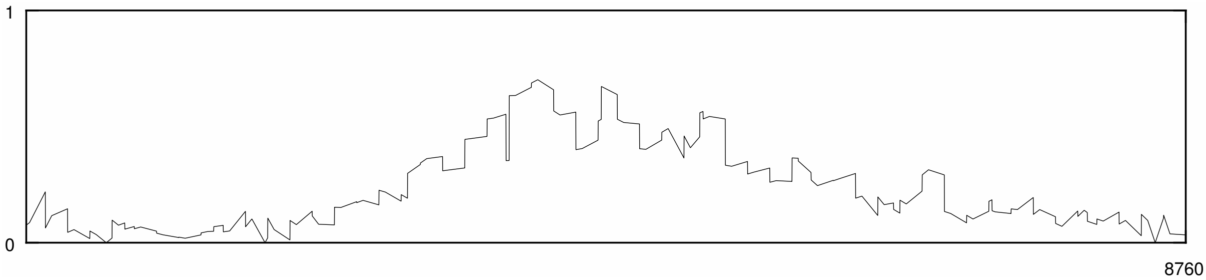
The energy storable in existing dams is 8835 GWh [31]. Currently in Switzerland there is an electricity deficit during winter and an electricity surplus during summer months. Hydroelectric



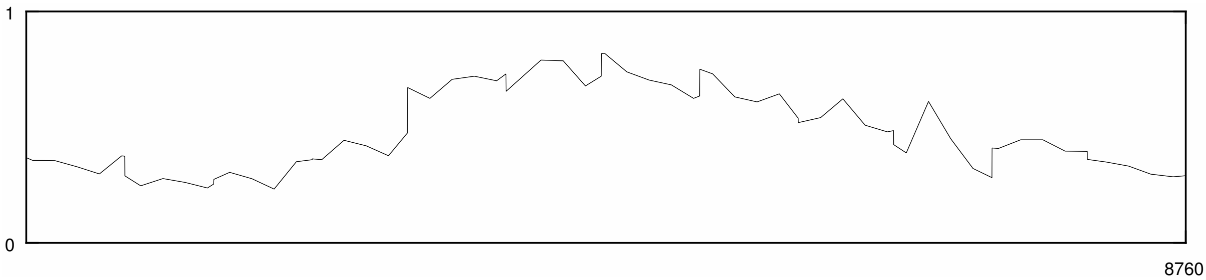
(a) Photovoltaic production



(b) Wind turbines production



(c) hydro dam inflow



(d) hydro river inflow

Figure 11: Capacity factor for the different renewable energy sources over the year. There is no hourly data source available giving the water inflows for hydro dam and hydro river (See Chapter 3 of [15]). However week data are available. To obtain hourly values, the weekly data are interpolated.

Table 13: Development potential for hydroelectricity in Switzerland [30].

	Additional net electricity production	
	Current conditions [GWh/y]	Optimized conditions [GWh/y]
New big plants	770	1430
Small hydro	1290	1600
Transformation, extension	870	1530
Total potential	2930	4560

Table 14: Development potential for hydroelectricity in Switzerland by 2050 [13].

	Additional net electricity production [GWh/y]
Small hydro	1600
Hydro run-of-river	2000
Hydro dams	900
Total potential	4500

dams help equilibrating the seasonal balance by storing a fraction of the water harvested during spring and summer, for additional electricity production in winter months. Nonetheless, this "shifting capacity" is limited, as dams are forced to turbine water during summer months (despite the excess of electricity production) to avoid the risk of dam overflow [32]. As a consequence, the energy stored in dams never reaches its maximum capacity. As an illustration, the maximum yearly energy stored has fluctuated around 85% of its maximum capacity over the seven last years [31]. Hence, in the model, we assume an available size of reservoir of 7500 GWh (85% of 8835 GWh).

Increasing the heights of existing dam has two consequences: an additional net electricity production (Table 16) and an additional storage capacity of 2400 GWh [33]. In the model, the energy stored in dams is represented by the *StoDam* technology, described methodology Section of the paper.
Table 17 and Table 18 contain the data used for the calculation of the specific investment and O&M costs reported in Table 10. The capacity factors calculated in Table 12 are used for the calculation of the installed power.

Table 15: Net hydroelectricity production and installed power in Switzerland in the years 2012 and 2050.

	2012 [28]		**2050**	
	Production [GWh/y]	**Power**[a] [GW]	**Production** [GWh/y]	**Power**[a] [GW]
Hydro river	16981	3.84	19895	4.69
Hydro dam	17297	8.08	17483	8.52

[a] The capacity factors in Table 12 are used to calculate the installed power in 2050.

Table 16: Development potential of hydroelectricity in Switzerland by 2050 [13, 30].

	Additional net electricity production	
	Hydro river [GWh/y]	**Hydro dam** [GWh/y]
Renovation	677	463
Dams height increase	0	330
New big plants	1324	108
New small plants	1600	0

Table 17: Investment cost data for the new hydro power plants in Switzerland.

	Hydro river			**Hydro dam**		
	Power [GW]	c_{inv} [CHF_{2015}/kW_e]	**Total Inv.** [10^6 CHF_{2015}]	**Power** [GW]	c_{inv} [CHF_{2015}/kW_e]	**Total Inv.** [10^6 CHF_{2015}]
Renovation	0.16	4278 [34]	683	0.23	2849 [34]	643
Dam height increase	-	-	-	0.16	3807	612[a]
New big plants [27]	0.31	5387	1681	0.05	4828	254
New small plants	0.38	7054[b]	2660	-	-	-
Total	0.85	5919	5023	0.44	3437	1509

[a] The investment cost for increasing the height of dams is proportional to the amount of extra electricity associated to the increased potential energy of the water: [0.8, 0.9] CHF_{2015}/kWh [33]. The mean of the interval is used in the calculations.

[b] Average between values in Table 2-4 and in Table 2-5 for new small plants in 2035 [34]

Table 18: O&M cost data for the new hydroelctric power plants in Switzerland.

	Hydro river			**Hydro dam**		
	Power [GW]	c_{maint} [$CHF_{2015}/kW_e/y$]	**Total O&M** [10^6 CHF_{2015}]	**Power** [GW]	c_{maint} [$CHF_{2015}/kW_e/y$]	**Total O&M** [10^6 CHF_{2015}]
Renovation	0.16	-	-	0.23	-	-
Dam height increase	-	-	-	0.16	-	-
New big plants [27]	0.31	54 [27]	16.8	0.05	24 [27]	1.27
New small plants	0.38	127[a]	47.9	-	-	-
Total	0.85	76.3	65.7	0.44	2.89	1.27

[a] Average between values in table 2-4 and in table 2-5 for new small plants in 2035 [34]

Data for the considered fossil electricity production technologies are listed in Table 19. The maximum installed capacity (f_{max}) is set to a value high enough (10 GW_e) for each technology to potentially cover the entire demand. For carbon capture and storage (CCS) technologies, a 90% capture rate is assumed.

Table 19: Non-renewable electricity supply technologies. Abbreviations: natural gas combined cycle (CCGT), carbon capture and storage (CCS), ultra-supercritical (U-S), integrated gasification natural gas combined cycle (IGCC)

	$\boldsymbol{f_{ref}}$ [GW]	$\boldsymbol{c_{inv}}$ [CHF_{2015}/kW_e]	$\boldsymbol{c_{maint}}$ [$CHF_{2015}/kW_e/y$]	$\boldsymbol{gwp_{constr}}$ [$kgCO_2$-eq./kW_e]	**Lifetime** [y]	$\boldsymbol{c_p}$ [%]	$\boldsymbol{\eta_e}$ [%]
Nuclear	1	5175[a]	110 [17]	707.9 [11]	60 [36]	84.9[b]	37
CCGT	0.5	824 [17]	21.1 [17]	183.8[c] [11]	25 [37]	85.0	63[d]
CCGT CCS	0.5	1273 [17]	30.2 [17]		25 [37]	85.0	57[e]
U-S Coal	0.5	2688[f]	31.7[f]	331.6[c] [11]	35 [37]	86.8 [37]	49[g]
U-S Coal CCS	0.5	4327[h]	67.6[h]		35 [37]	86.8 [37]	42[i]
IGCC	0.5	3466[j]	52.3[j]		35 [37]	85.6 [37]	54[k]
IGCC CCS	0.5	6045[l]	73.9[l]		35 [37]	85.6 [37]	48[m]

[a] Investment cost: 3664 CHF_{2015}/kW_e [17] + dismantling cost in Switzerland: 1511 CHF_{2015}/kW_e [35].
[b] Data for the year 2012 [19]
[c] In the lack of specific data, assuming same impact for standard and CCS power plants.
[d] 0.4-0.5 GW_e CCGT in 2035 (realistic optimistic scenario) [37].
[e] CCGT with post-combustion CCS in 2025 (very optimistic scenario) [37].
[f] 1.3 GW_e advanced pulverized coal power plant [38]. c_{maint} is fixed cost (31.18 $CHF_{2015}/kW_e/y$) + variable cost (0.54 $CHF_{2015}/kW_e/y$ assuming 7600 h/y).
[g] Pulverized coal in 2025 (realistic optimistic scenario) [37].
[h] 1.3 GW_e advanced pulverized coal power plant with CCS [38]. c_{maint} is fixed cost (66.43 $CHF_{2015}/kW_e/y$) + variable cost (1.15 $CHF_{2015}/kW_e/y$ assuming 7600 h/y).
[i] Pulverized coal with post-combustion CCS in 2025 (realistic optimistic scenario) [37].
[j] 1.2 GW_e IGCC power plant [38]. c_{maint} is fixed cost (51.39 $CHF_{2015}/kW_e/y$) + variable cost (0.88 $CHF_{2015}/kW_e/y$ assuming 7500 h/y).
[k] integrated gasification natural gas combined cycle (IGCC) in 2025 (realistic optimistic scenario) [37].
[l] 0.52 GW_e IGCC power plant with CCS [38]. c_{maint} is fixed cost (72.83 $CHF_{2015}/kW_e/y$) + variable cost (1.03 $CHF_{2015}/kW_e/y$ assuming 7500 h/y).
[m] IGCC with post-combustion CCS in 2025 (realistic optimistic scenario) [37].

The modeled seasonal storage option consists in the production of synthetic methane from the excess of electricity. This synthetic methane is then used for producing electricity during periods of deficit in electricity supply. This procedure is also known as Power-to-NG-to-Power. The seasonal storage model is based on the liquified CH_4-CO_2 system (LM-C) presented by Al-musleh et al. [39]. It consists of a reversible fuel cell (FC) which is used as electrolyzer to produce hydrogen when there is excess electricity in the grid. The hydrogen is sent to a methanation reactor where it is mixed with CO_2 to produce methane which is liquified (LNG) previous to storage. When there is a shortage of electricity, the methane is gasified and oxidized in the FC to produce electricity. The produced CO_2 is liquified and stored for being used as input of the methanation reaction; thus, this system is a carbon closed loop, as there is no emission of CO_2.

The elements considered for the calculation of the investment and O&M costs are the reversible FC, the liquefaction train and the tanks for storing CH_4 and CO_2. The data required for the cost calculation is available in Table 20. It has been assumed that the O&M cost (c_{maint}) are 5% of the initial investment cost, and that the lifetime of the different components is 25 years.

Table 20: Data for the seasonal power to gas storage cost calculation.

	Parameter	**Unit**	**Value**
Technical data [39]	Lower Heating Value (LNG)	[MJ/kg]	50
		[MJ/m^3]	21882
	Roundtrip efficiency	[%]	56.1[a]
	Storage requirement	[$m^3_{CH_4}$/$GWh_{e,out}$]	232
		[$m^3_{CO_2}$/$GWh_{e,out}$]	264
Specific investment cost (c_{inv})	Tank	[$kCHF_{2015}$/$GWh_{e,out}$]	585[b]
	Liquefaction plant	[CHF_{2015}/kW_{LNG}]	233[c]
	Reversible FC	[CHF_{2015}/kW_e]	2934[d]

[a] Power-to-LNG efficiency is 79.2% and LNG-to-Power efficiency is 70.8% [39].
[b] Accounting for the investment of the CO_2 and CH_4 tanks. Based on the average of the cost interval 94-283 $MCHF_{2015}$ for a 160000 m^3 tank in Hjorteset et al. [40], i.e. 1180 CHF_{2015}/m^3.
[c] Average of the points in [41] (Figure 17), excluding high cost locations.
[d] Same specific investment as the advanced cogeneration technology (Table 23).

2.2.2 Electricity grid

The replacement cost of the Swiss electricity grid is 58.6 billions CHF_{2015} [42] and its lifetime is 80 years [43]. The electricity grid will need additional investment depending on the penetration level of the decentralized and stochastic electricity production technologies. The needed investements are expected to be 2.5 billions CHF_{2015} for the high voltage grid and 9.4 billions CHF_{2015} for the medium and low voltage grid. These values correspond to the scenario 3 in [42]. The lifetime of these additional investments is also assumed to be 80 years.

2.3 Heating and cogeneration technologies

Table 21, Table 22 and Table 23 detail the data for the considered industrial, centralized and decentralized CHP technologies, respectively. In some cases, it is assumed that industrial (Table 21) and centralized (Table 22) technologies are the same.
f_{min} and f_{max} for heating and CHP technologies are 0 and 20 GW_{th}, respectively. The latter value is high enough for each technology to supply the entire heat demand in its layer. Thus, for heating and cogeneration technologies the maximum and minimum shares are controlled in the model by $f_{min,\%}$ and $f_{max,\%}$, respectively.

For the DHN, the investment for the network is also accounted for. The specific investment (c_{inv}) is 882 CHF_{2015}/kW_{th}. This value is based on the mean value of all points in [50] (Figure 3.19), assuming a full load hours of 1535 per year (see table 4.25 in [50]). The lifetime of the DHN is expected to be 60 years. The lower ($\%_{dhn,min}$) and upper bounds ($\%_{dhn,max}$) for the use of DHN are 10% and 30% of the annual low temperature heat demand, respectively.

Figure 12 represents the capacity factor ($c_{p,t}$) of solar thermal panels. In addition, Table 24 reports the monthly distribution factors (data from Appendix D of [15]). For all the other heat supply technologies (renewable and non-renewable) $c_{p,t}$ is equal to the default value of 1.

Table 21: Industrial heating and cogeneration technologies.

	f_{ref} [MW]	c_{inv} [CHF$_{2015}$/kW$_{th}$]	c_{maint} [CHF$_{2015}$/kW$_{th}$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_{th}$]	**Lifetime** [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
CHP NG	20	1504[a]	98.9[b]	1024 [11]	20 [37]	85	44[c]	46[c]	0	50
CHP Wood[d]	20	1154 [17]	43.2 [17]	165.3 [11]	25 [44]	85	18 [17]	53 [17]	0	100
CHP Waste	20	3127[e]	119[e]	647.8[f]	25 [44]	85	20 [44]	45 [44]	0	50
Boiler NG	10	62.9[g]	1.26[g]	12.3[h]	17 [45]	95	0	92.7[g]	0	60
Boiler Wood	10	123[g]	2.46[g]	28.9 [11]	17 [45]	90	0	86.4[g]	0	100
Boiler Oil	10	58.6[i]	1.26[j]	12.3 [11]	17 [45]	95	0	87.3[g]	0	50
Boiler Coal	1	123[k]	2.46[k]	48.2 [11]	17 [45]	90	0	82	0	50
Boiler Waste	1	123[k]	2.46[k]	28.9[l]	17 [45]	90	0	82	0	100
Direct Elec.	0.1	355[m]	1.61[m]	1.47 [11]	15	95	0	100	0	20

[a] Calculated as the average of investment costs for 50 kW$_e$ and 100 kW$_e$ internal combustion engine cogeneration systems [13].
[b] Calculated as the average of investment costs for 50 kW$_e$ and 100 kW$_e$ internal combustion engine cogeneration systems [34].
[c] 200 kW$_e$ internal combustion engine cogeneration NG system, very optimistic scenario in 2035 [37].
[d] Biomass cogeneration plant (medium size) in 2030-2035.
[e] Biomass-waste-incineration CHP, 450 scenario in 2035 [17].
[f] Impact of municipal solid waste (MSW) incinerator in [6], using efficiencies reported in the table.
[g] from [6]
[h] Assuming same impact as industrial oil boiler.
[i] 925 kW$_{th}$ oil boiler (GTU 530) [46]
[j] Assumed to be equivalent to a NG boiler.
[k] Assumed to be equivalent to a wood boiler.
[l] Assuming same impact as industrial wood boiler.
[m] Commercial/public small direct electric heating [47].

Table 22: District heating technologies.

	f_{ref} [MW]	c_{inv} [CHF$_{2015}$/kW$_{th}$]	c_{maint} [CHF$_{2015}$/kW$_{th}$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_{th}$]	**Lifetime** [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
HP	1	368[a]	12.8[b]	174.8 [11]	25	95	0	400	0	50
CHP NG	20	1340[c]	40.1[c]	490.9[d]	25 [37]	85	50[e]	40[e]	0	50
CHP Wood[f]	20	1154 [17]	43.2	165.3	25 [44]	85	18 [17]	53 [17]	0	100
CHP Waste[f]	20	3127	119	647.8	25 [44]	85	20 [44]	45 [44]	0	50
Geothermal[g]	23	1620	60.1	808.8 [11]	30	85	0	100	0	50
Boiler NG[f]	10	62.9[h]	1.26[h]	12.3	17 [45]	95	0	92.7[h]	20	80
Boiler Wood[f]	10	123[h]	2.46[h]	28.9	17 [45]	90	0	86.4[h]	0	100
Boiler Oil[f]	10	58.6	1.26	12.3	17 [45]	95	0	87.3[h]	0	50

[a] Calculated with the equation: c_{inv} [EUR$_{2011}$] $= 3737.6 * E^{0.9}$, where E is the electric power (kW$_e$) of the compressor, assumed to be 2150 kW$_e$. Equation from [48], taking only the cost of the technology (without installation factor).
[b] Ground-water heat pump with 25 years lifetime [49].
[c] CCGT with cogeneration [17].
[d] Impact of NG CHP in from [6], using efficiencies reported in the table.
[e] η_e and η_{th} at thermal peak load of a 200-250 MW$_e$ CCGT plant, realistic optimistic scenario in 2035 [37].
[f] Assumed same technology as for industrial heat and CHP (Table 21)
[g] Direct use of a geothermal well at 4.2 km depth (from [6]).
[h] from [6]

Table 23: Decentralized heating and cogeneration technologies.

	f_{ref} [MW]	c_{inv} [CHF_{2015}/kW_{th}]	c_{maint} [$CHF_{2015}/kW_{th}/y$]	gwp_{constr} [$kgCO_2$-eq./kW_{th}]	Lifetime [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
HP	0.01	525^{ab}	22.5^{c}	164.9 [11]	18^{c}	100	0	300	0	50
Thermal HP	0.01	337^{db}	10.1^{e}	381.9 [11]	20	100	0	150	0	20
CHP NG^{f}	0.005	1504	98.9	1024	20 [37]	100	44	46	0	40
CHP Oil	0.01	1394^{g}	87.5^{h}	1024^{i}	20	100	39^{j}	43^{j}	0	40
FC NG	0.01	7734^{k}	155^{l}	2193 [11]	20 [54]	100	58^{m}	22^{m}	0	20
FC H_2^{n}	0.01	7734	155	2193	20 [54]	100	58	22	0	20
Boiler NG	0.01	169^{o}	5.08^{o}	21.1^{o}	17 [45]	100	0	90^{o}	20	80
Boiler Wood	0.01	494 [55]	17.3 [55]	21.1^{p}	17 [45]	100	0	85 [55]	0	100
Boiler Oil	0.01	152 [46]	9.12^{q}	21.1^{o}	17 [45]	100	0	85^{o}	10	50
Solar Th.	0.01	768^{r}	8.64^{s}	221.2 [11]	20 [47]	11.3^{t}	0	-	0	40
Direct Elec.	0.01	42.7^{u}	0.19^{v}	1.47 [11]	15 [47]	100	0	100	0	20

[a] 10.9 kW_{th} Belaria compact IR heat pump [51].

[b] Catalog data divided by 2.89. 2.89 is the ratio between Swiss catalog prices and prices found in the literature. Calculated by dividing the average price of a decentralized NG boiler (489 CHF_{2015}/kW_{th}) in Swiss catalogs [52] by the price for the equivalent technology found in literature (169 CHF_{2015}/kW_{th}, from [6]).

[c] 6 kW_{th} air-water heat pump [47].

[d] Specific investment cost for a 15.1 kW_{th} absorption heat pump (Vitosorp 200-F) [52]

[e] 3% of c_{inv} (assumption).

[f] Assumed same technology as for industrial CHP NG (Table 21)

[g] Assumed to be equivalent to a 100 kW_e internal combustion engine cogeneration NG system [13].

[h] Assumed to be equivalent to a 100 kW_e internal combustion engine cogeneration NG system [34].

[i] Assuming same impact as decentralized NG CHP.

[j] Efficiency data for a 200 kW_e diesel engine [11]

[k] System cost (including markup) for a 5 kW_e solid-oxide FC system, assuming an annual production of 50000 units [53].

[l] 2% of the investment cost [17].

[m] Solid-oxide FC coupled with a NG turbine, values for very optimistic scenario in 2025 [54].

[n] Assumed to be equivalent to FC NG.

[o] from [6]

[p] Assuming same impact as NG and oil decentralized boilers.

[q] 6% of c_{inv}, based on ratio between investment and O&M cost of boiler of similar size in [45].

[r] 504 CHF_{2015}/m^2 for the UltraSol Vertical 1V Hoval system [51]. For conversion from CHF_{2015}/m^2 to CHF_{2015}/kW_{th}, it is assumed an annual heat production of 650 kWh/m^2 (average for the best oriented roofs in the town of Verbier, Switzerland [56]).

[s] 1.1% of the investment cost, based on ratio investment-to-O&M cost in [47].

[t] The calculation of the capacity factor for solar thermal is based on the SPF model [57] with radiation data from the village of Verbier, Switzerland. It has been assumed that the mean temperature of the water inside the panel is 40?C.

[u] Resistance heaters with fan assisted air circulation in [45].

[v] In the lack of specific data, same investment-to-O&M ratio as for direct electric heating in the industry sector (Table 21).

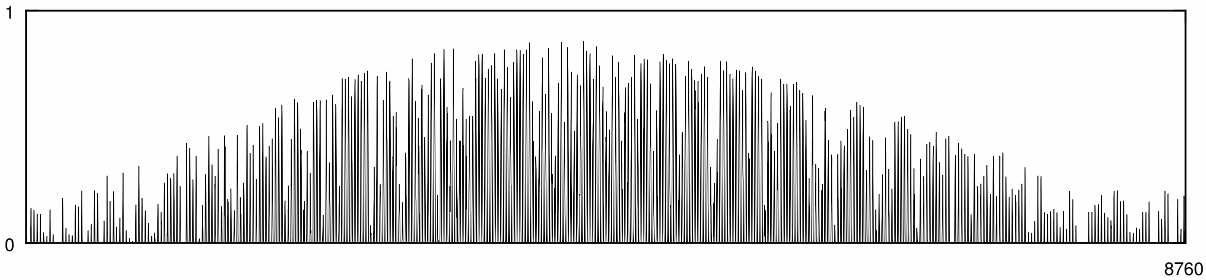


Figure 12: Capacity factor of thermal solar panels over the year.

Table 24: Aggregated monthly heat production share from decentralized solar thermal panels.

	Aggregated monthly heat production share ($dist_t$) [-]											
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Solar Thermal	0.012	0.027	0.065	0.109	0.155	0.163	0.158	0.144	0.077	0.058	0.020	0.013

2.4 Transport

In the model, for transport technologies only the operating cost (fuel consumption) is considered. Investment, O&M costs and emissions associated to the construction are not accounted for. The efficiencies for the passenger vehicles in 2035 (Table 25) are calculated with a linear interpolation between the 2010 and 2050 values presented in Table 6 in Codina Gironès et al [58]. For private mobility, the average occupancy assumed in [58] is 1.6 passenger/vehicle (data for the year 2010 in Switzerland, from [59]).

Table 25: Fuel and electricity consumption for transport technologies in 2035 [58], and minimum/maximum shares allowed in the model.

Vehicle type	**Fuel** [kWh/pkm]	**Electricity** [kWh/pkm]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
Gasoline car	0.430		20	100
Diesel car	0.387		20	100
NG car	0.483		0	50
Hybrid electric vehicle (HEV)[a]	0.247		0	30
Plug-in hybrid electric vehicle (PHEV)[b]	0.176	0.045	0	30
BEV		0.107	0	30
FC car	0.179		0	20
Tram and Trolley Bus		0.165	0	30
Diesel Bus and Coach	0.265		0	30
Diesel HEV Bus and Coach	0.183		0	30
NG Bus and Coach	0.306		0	30
FC Bus and Coach	0.225		0	20
Train		0.092	0	80

[a] Using gasoline as only fuel.
[b] It is assumed that electricity is used to cover 40% of the total distance and petrol to cover the remaining 60%.

The technologies available for freight transport are trains and trucks. Trains are considered to be only electric. Their efficiency in 2035 is 0.069 kWh/tkm [58]. The efficiency for freight transport by truck is 0.51 kWh/tkm based on the weighted average of the efficiencies for the vehicle mix in [58].

The maximum number of cars is assumed to be equivalent to have all the drivers owning a car (5.8 millions person in Switzerland [10]). The size of the BEV batteries is assumed to be the one from a Nissan Leaf (ZE0) (24 kWh[13]). The size of the PHEV batteries is assumed to be the one from Prius III Plug-in Hybrid (4.4 kWh[14]). The performances of BEV and PHEV batteries are assimilated to a Li-ion battery as presented in Table 28.

[13] from `https://en.wikipedia.org/wiki/Nissan_Leaf`, consulted on 29-01-2019
[14] from `https://fr.wikipedia.org/wiki/Toyota_Prius`, consulted on 29-01-2019

2.5 Resources

The availability of all resources, except for wood and MSW, is set to a value high enough to allow unlimited use in the model. No import of hydrogen or biofuels is accounted for in the implementation. Wood availability is 12279 GWh/y [60] ("wet wood", 50% humidity, LHV_{wb} = 8.279 MJ/kg_{wb}, from [6]), while MSW is limited to 11142 GWh. For the calculation of the MSW availability it is considered that the average *per capita* annual waste production is 730 kg (2014 data for Switzerland, from [61]), 50% of it is recycled [62] and the lower heating value (LHV) is 12.35 MJ/kg (from [6]). The number of inhabitants in Switzerland in 2035 is expected to be 8.90 millions [13].

Table 26 details the prices of resources (c_{op}) and the GHG emissions (gwp_{op}) associated to their production, transportation and combustion. c_{op} for imported biofuels is assumed to be equal to the price of the respective fossil equivalent. No cost is associated to the MSW, as it is assumed that it should be collected anyway. Export of electricity are possible, but they are associated to a zero selling price.

Table 26: Price and GHG emissions of resources.

Resources	$\boldsymbol{c_{op}}$ [CHF_{2015}/MWh_{fuel}]	$\boldsymbol{gwp_{op}}$ [$kgCO_2$-eq./MWh_{fuel}]
Electricity Import	90.06[a]	482[b]
Gasoline	87.96[c]	345[b]
Diesel	85.16[d]	315[b]
Light fuel oil (LFO)	60.59[e]	311.5[b]
NG	34.82[f]	267[b]
Wood	93.24[g]	11.8[b]
MSW	0	150[b]
Coal	30.17[h]	401 [11]
Uranium	4.140[i]	3.9 [11]

[a] Based on average market price in the year 2010 (50 EUR_{2010}/MWh, from [63]). Projected from 2010 to 2035 using a multiplication factor of 1.36 [13].

[b] from [6]

[c] Based on 1.49 CHF_{2015}/L (average price in 2015 for gasoline 95) [64]. Taxes (0.86 CHF_{2015}/L, [65]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [66].

[d] Based on 1.55 CHF_{2015}/L (average price in 2015) [64]. Taxes (0.87 CHF_{2015}/L, [65]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [66].

[e] Based on 0.705 CHF_{2015}/L (average price in 2015 for consumptions above 20000 L/y) [67]. Taxes (0.22 CHF_{2015}/L, [65]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [66].

[f] Based on 24.95 CHF_{2015}/MWh, average import price in the years 2015-2016 at the Swiss border. Projected from 2015 to 2035 using a multiplication factor of 1.40 [66]. Import price data received by e-mail from the Swiss Federal Officie of Statistics (SFOS) [68], Feb. 2017.

[g] It is based on 47.58 CHF_{2015}/MWh (from [6]), and projected from 2015 to 2035 using a multiplication factor of 1.96 [13].

[h] It is based on 18.06 CHF_{2011}/MWh [69], and projected from 2011 to 2035 using a multiplication factor of 1.46 [66].

[i] Average of the data points for 2035 in [70], accounting for the efficiency of nuclear power plants (Table 19).

2.6 Storage

Table 27 and 28 detail the data for the storage technologies (except hydro dams which has been presented in Section sec:hydro). Table 27 summarises the cost of investment, GWP, lifetime and potential integration of the different technologies. Table 28 summarises the technical performances of each technology.

Table 27: Storage technologies characteristics: cost, emissions, lifetime and potential.

	f_{ref} [MW]	c_{inv} [CHF_{2015}/kWh]	c_{maint} [CHF_{2015}/kWh/y]	gwp_{constr} [$kgCO_2$-eq./kW_{th}]	**Lifetime** [y]	f_{min} [GWh]	f_{max} [GWh]
Li-on batt.	1e-6	1000[a]	0	61.3[b]	15[c]	0	∞
PHS	1	4.98[de]	0.02[f]	8.33[eg]	50[c]	369[e]	1700[e]
TS dec.	5.9e-6[f]	20.26[h]	0[f]	0[f]	25[h]	0	∞
TS seas. cen.	0.99[f]	3.36[h]	0[f]	0[f]	25[h]	0	∞
TS daily cen.	5.9e-6[f]	10.13[h]	0[f]	0[f]	25[h]	0	∞

[a] Data from Table 1 of [71].
[b] Data from Table 4 of [72].
[c] Data verified in Table B1 of [73].
[d] The cost is around 1 000 [CHF_{2015}/kW] [74]. Hence, the specific cost is 5 [CHF_{2015}/kWh].
[e] In 2010, the PHS energy capacity was 369 [GWh] for a power capacity of 1.817 [GW] [75]. Hence the power to energy ratio is 203 [h].
[f] Own calculation.
[g] Own calculation based on Hydro Dams emissions.
[h] Adapted from Table 5.2 of [76].

2.7 Other parameters

2.7.1 Hydrogen production

Three technologies are considered for hydrogen production: electrolysis, NG reforming and biomass gasification. The last two options include CCS systems for limiting the CO_2 emissions. Table 29 contains the data for the hydrogen production technologies.

2.7.2 Biomass to synthetic fuels

Two technology options are considered for the conversion of woody biomass to synthetic fuels: pyrolysis and gasification. The main product of the pyrolysis process is bio-oil, which is considered equivalent to fossil LFO. The main product of the gasification process is synthetic natural gas (SNG), which is considered equivalent to fossil NG. Data for the technologies are reported in Table 30 (from [6]). In the table, efficiencies are calculated with respect to the wood in input (50% humidity, on a wet basis LHV) and "fuel" stands for the main synthetic fuel in output.

2.7.3 Energy demand reduction cost

The energy efficiency cost is a cost difference between the "business as usual" scenario, which has the highest energy demand, and the "Political measures of the Federal Council" scenario in [13]. The cost is divided in two categories: private households and industry and services. The values are 806 $MCHF_{2015}$/y and 1050 $MCHF_{2015}$/y respectively [79]. As in the model only the "PMF" scenario is considered for the energy demand (Table 7), the demand reduction is a fixed cost in the model.

2.7.4 Other

The real discount rate for the public investor i_{rate} is fixed to 3.215%, average of the range of values used to define the corresponding uncertainty range (see Section 2.2.2 in [6]).

Table 28: Storage technologies characteristics: efficiencies, energy to power ratios, losses and availabilities.

	$\eta_{sto,in}$ [-]	$\eta_{\mathbf{sto,out}}$ [-]	$\mathbf{t_{sto_{in}}}$ [h]	$\mathbf{t_{sto_{out}}}$ [h]	$\%_{sto_{loss}}$ [s^{-1}]	$\%_{sto_{avail}}$ [-]
Li-on batt.	0.95[a]	0.95[a]	4[a]	4[a]	2e-4[b a]	1
BEV batt.	0.95[a]	0.95[a]	4[c]	10[c]	2e-4[b a]	0.2[c]
PHEV batt.	0.95[a]	0.95[a]	4[c]	10[c]	2e-4[b a]	0.2[c]
PHS	0.9[a]	0.9[a]	203[d]	203[d]	0[e]	1
TS dec.	1[e]	1[e]	4[c]	4[c]	82e-4[f]	1
TS seas. cen.	1[e]	1[e]	168[g]	168[g]	4.2e-5[f]	1
TS daily cen.	1[e]	1[e]	2[c]	2[c]	7.5e-4[f]	1

[a] Data verified in Table B1 of [73].
[b] Data from Table 4 of [72].
[c] Own calculation.
[d] In 2010, the PHS energy capacity was 369 [GWh] for a power capacity of 1.817 [GW] [75]. Hence the power to energy ratio is 203 [h].
[e] Neglected.
[f] Adapted from Table 5.2 of [76]
[g] Assumed to take 1 week to full charge.

Table 29: Hydrogen production technologies.

	c_{inv} [CHF_{2015}/kW_{H2}]	c_{maint} [$CHF_{2015}/kW_{H2}/y$]	**Lifetime** [y]	c_p [%]	$\eta_{\mathbf{H2}}$ [%]
Electrolysis [77]	329	32.9[a]	15	90	85
CH_4 reforming [78]	728	68.8	25[b]	86	73
Biomass gasification [78]	2697	209	25[b]	86	43

[a] Assumed to be 10% of c_{inv}, for coherence with the data in [78].
[b] Assumption.

Table 30: Woody biomass to synthetic fuels conversion technologies (from [6]).

	c_{inv} [CHF_{2015}/kW_{fuel}]	c_{maint} [$CHF_{2015}/kW_{fuel}/y$]	**Lifetime** [y]	c_p [%]	$\eta_{\mathbf{fuel}}$ [%]	$\eta_{\mathbf{e}}$ [%]	$\eta_{\mathbf{th}}$ [%]
Pyrolysis	1435	71.8	25	85	66.6	1.58	-
Gasification	2930	149	25	85	74	3.15	9.01

Losses ($\%_{net_{loss}}$) in the electricity grid are fixed to 7%. This is the ratio between the losses in the grid and the total annual electricity production in Switzerland in 2015 [80]. DHN losses are assumed to be 5%.
The input and output efficiency of the storage ($\eta_{sto,in}$ and $\eta_{sto,out}$) are defined to allow the connection between the storage technologies (*StoHydro* and *Power2Gas*) and their respective layers (electricity and LNG, respectively). The efficiency is 1 in all cases as the *StoHydro* unit represents a "shift" in the monthly production of the dams, while the LNG storage tank is assumed to have no losses.

2.8 2011 data for model verification

This section details the data of the Swiss energy system in the year 2011 used to validate the mixed-integer linear programming (MILP) model in the validation Section of the paper. The input data for the year 2011 used for the model validation are: *i*) the yearly EUD values in the different sectors ($endUses_{year}$); *ii*) the relative annual production shares of the different technologies for each type of EUD; *iii*) the share of public mobility ($\boldsymbol{\%_{Public}}$), of train in freight ($\boldsymbol{\%_{Rail}}$) and of centralized heat production ($\boldsymbol{\%_{Dhn}}$); *iv*) the fuel efficiency of mobility technologies.

The FEC data for Switzerland in the year 2011 are available in [13, 59, 81]. The EUD is calculated based on the FEC using a similar procedure as the one described in Section 2.1.1. The obtained input data for model verification are reported in Table 31. $\boldsymbol{\%_{Public}}$, $\boldsymbol{\%_{Rail}}$ and $\boldsymbol{\%_{Dhn}}$ are reported in Table 32 with the corresponding sources.

Table 31: End-uses demand in Switzerland ($endUses_{year}$) in 2011, calculated from [13, 59, 81].

	Units	**Households**	**Services**	**Industry**	**Transportation**
Electricity (other)	[GWh]	10277.8	11166.7	13416.7	0.0
Lighting	[GWh]	1583.3	4138.9	1722.2	0.0
Heat high T	[GWh]	0.0	1146.4	22020.4	0.0
Heat low T (SH)	[GWh]	38861.1	15584.2	4982.7	0.0
Heat low T (HW)	[GWh]	8236.1	3153.0	839.9	0.0
Passenger mobility	[Mpkm]	0.0	0.0	0.0	121600.0
Freight mobility	[Mtkm]	0.0	0.0	0.0	27660.0

Table 32: $\boldsymbol{\%_{Public}}$, $\boldsymbol{\%_{Rail}}$ and $\boldsymbol{\%_{Dhn}}$ for the Swiss energy system in the year 2011.

	Share [%]
$\boldsymbol{\%_{Public}}$	20.0% [59]
$\boldsymbol{\%_{Rail}}$	36.8% [13]
$\boldsymbol{\%_{Dhn}}$	6.4% [13, 81]

The annual net electricity production shares for electricity production technologies is taken from [82]. The yearly shares of mobility and heating & CHP technologies per type of EUD (with respect to the main output) are reported in Tables 33-37.
For public mobility (Table 33, [81, 82]), it is assumed that all biofuels and NG are used in public mobility, and that the electricity not used in freight is shared between trains and trolleybus with a 60%-40% share, respectively. For private mobility (Table 34, [59, 81]) the repartition between

the different types of vehicles is estimated based on the number of vehicles in Switzerland in 2012 (77% gasoline, 22% diesel, 1% hybrid) and their fuel efficiencies. For all mobility technologies, 2010 efficiencies from [58] are used in the model verification.
For low and high temperature heat production (Tables 35, 36 and 37, [13, 81–83]), the electricity production from CHP plants is taken from [83], Table A.2), while the input fuel and the heat production are estimated based on the efficiencies assumed for 2035. In the validation Section of the paper, for DHN it is assumed that all waste is used in CHP units, although in reality a share of waste is only used for electricity production.

Table 33: Yearly shares of public mobility technologies for the Swiss energy system in 2011.

	Share Mpkm [%]
Tram and Trolley Bus	12.8%
Diesel Bus and Coach	49.7%
Diesel HEV Bus and Coach	0.0%
NG Bus and Coach	3.0%
FC Bus and Coach	0.0%
Train/Metro	34.6%

Table 34: Yearly shares of private mobility technologies for the Swiss energy system in 2011.

	Share Mpkm [%]
Gasoline car	75.8%
Diesel car	22.5%
NG car	0.0%
HEV	1.7%
PHEV	0.0%
BEV	0.0%
FC car	0.0%

3 User manual

The code, its documentation and the case study are gathered on a GitHub repository[1]. A `README.md` files summarises how to launch the energy model in four steps. Here below, we propose an extensive explanation including how to compute the typical days and manage data. The data are managed through excel files which are related ones to each others. The models are coded in AMPL, using the solver CPLEX. However, the energy model proposed can be run using the open-source GLPK and the GLPSOL solver.

3.1 Files structure and download

EnergyScope Typical Days (EnergyScope TD) is structured as shown in Figure 13. A main folder contains three sub-folders, first one is dedicated to data management. Second, for the files related to typical days selection (STEP 1). Third and last branch regroups the files related to the energy model (STEP 2). Table 38 describes each files.

By ensuring that the download files respect the structure, the links between files should be respected and User could use the quick start procedure to launch the code.

Table 35: Yearly shares of decentralized low temperature heat & CHP technologies for the Swiss energy system in 2011.

	Share heat [%]
HP	6.0%
Thermal HP	0.0%
CHP NG	0.5%
CHP Oil	0.1%
FC NG	0.0%
FC H_2	0.0%
Boiler NG	25.7%
Boiler Wood	8.2%
Boiler Oil	49.8%
Solar Th.	0.5%
Direct Elec.	9.2%

Table 36: Yearly shares of DHN low temperature heat & CHP technologies for the Swiss energy system in 2011.

	Share heat [%]
HP	4.8%
CHP NG	1.2%
CHP Wood	6.6%
CHP Waste	72.5%
Boiler NG	13.8%
Boiler Wood	0.0%
Boiler Oil	0.6%
Deep Geothermal	0.4%

Table 37: Yearly shares of industrial high temperature heat & CHP technologies for the Swiss energy system in 2011.

	Share heat [%]
CHP NG	2.4%
CHP Wood	0.8%
CHP Waste	1.8%
Boiler NG	24.3%
Boiler Wood	7.0%
Boiler Oil	25.6%
Boiler Coal	5.1%
Boiler Waste	5.6%
Direct Elec.	27.5%

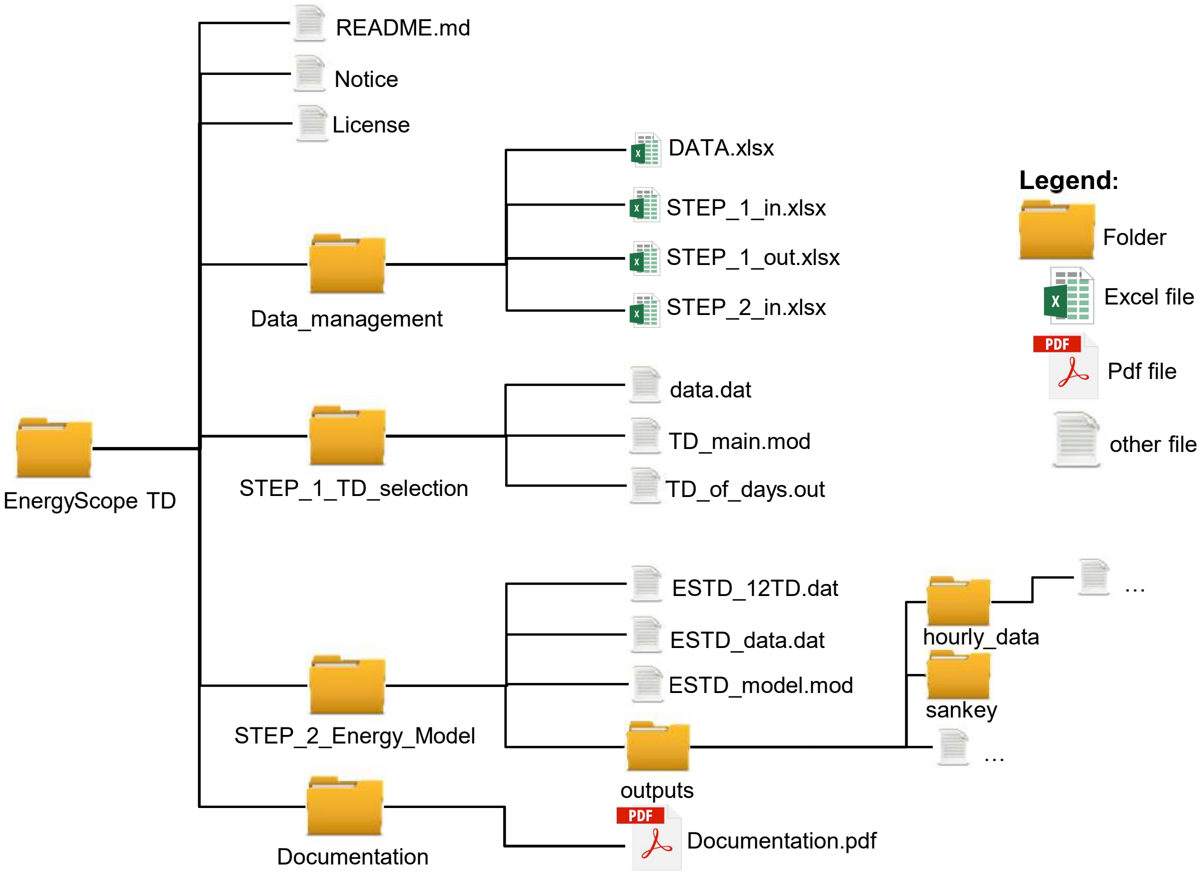


Figure 13: Files and folder structure

Table 38: Description of the files in Figure 13.

Folder	File name	Description
EnergyScope TD	`README.md`	Read me file
	`Notice`	List of contributions and references
	`License`	License file
Data	`DATA.xlsx`	All the input data
	`STEP_1_in.xlsx`	Prepare data for step 1
	`STEP_1_out.xlsx`	Process data from step 1
	`STEP_2_in.xlsx`	Prepare data for step 2
STEP1	`data.dat`	Data file for MILP problem
	`TD_main.mod`	MILP problem
	`TD_of_days.out`	Output of MILP problem: sequence of days.
STEP2	`ESTD_12TD.dat`	Data file for LP problem related to time series and sequence of days for 12 TDs
	`ESTD_data.dat`	Data file for LP problem related to technologies, scenarios...
	`ESTD_model.mod`	LP problem
Documentation	`Supplementary Material.pdf`	Full documentation of the code and data

3.2 Quick start

Figure 14 represents how data are managed between files listed in Figure 13 and how they are related to each others. in the following section, we will describe how to change the inputs data in `DATA.xlsx`, how to select typical days (STEP 1) and how to launch the energy system (STEP 2).

Each step is not mandatory, as User can skip a step and use the, already implemented, case which has all the input data to represent the Swiss energy system. Hence, Users who directly download the energy model and run it, will obtain the results presented in the paper.

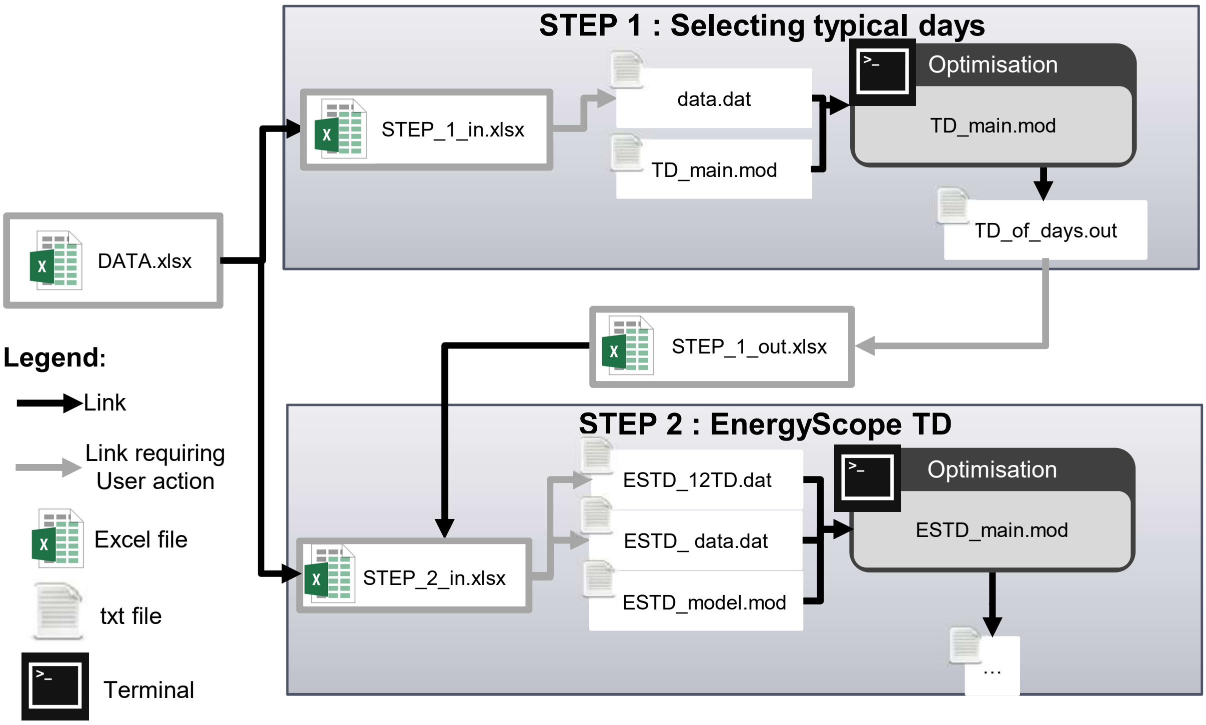


Figure 14: Management of files. Black arrows represent automatic actions instead of grey arrows which require User action. Example, from the `DATA.xlsx` file, the input for the first step (`STEP_1_in.xlsx`) are automaticaly loaded (black arrow). The file computes the loaded information to generate the data required for the MILP problem. These data must be copy-paste on the `data.dat` file (grey arrow).

3.2.1 Data

The `DATA.xlsx` file regroups all the required input data. An extensive description of these are given in Appendix 2. In the `DATA.xlsx` file, user can change each data, such as the cost of a technology, time series, the availability of resources or the maximum amount of wind turbines. The updated output files will be automatically generated, and user will just need to copy paste them as described in Figure 14.

3.2.2 Step 1: selecting typical days

Input

File `STEP_1_in.xlsx` loads the required data from the `DATA.xlsx` file, such as time series or number of typical days. The data required for STEP 1 MILP are generated in the `.dat` tab. User might copy-paste the tab in the `data.dat` file.

Run

Navigate to the subfolder `.\STEP_1_TD_selection` folder via terminal/cmd prompt and execute (check glpsol documentation for more options):

- Linux: `glpsol -m TD_main.mod -d data.dat`
- Mac OS X: `glpsol -m TD_main.mod -d data.dat`
- Windows: `glpsol.exe -m TD_main.mod -d data.dat`

Output

Results of the computation are recorded in `TD_of_days.out`. It contains the sequence of TDs over the year. This data must be copied-pasted in file `STEP_1_out.xlsx`.

3.2.3 Step 2: Energy model

Input

File `STEP_2_in.xlsx` loads the required data from the `DATA.xlsx` and `STEP_1_out.xlsx` files. Then, required data are generated and must be copied-pasted. From the excel tabs `ESTD_data.dat` and `ESTD_12TD.dat` to files `ESTD_data.dat` and `ESTD_12TD.dat`, respectively. Here, we choose 12 typical days, but the `STEP_1_out.xlsx` file generates also files for 4, 8, 24, 48 and 365 typical days. File `ESTD_data.dat` encompass all the information not related to typical days, such as technologies characterisations, resources prices and availability etc... File `ESTD_12TDs.dat` encompass the time series related to 12 typical days and the relation between TDs and days.

Run

Navigate to the subfolder `.\STEP_2_Energy_Model` via terminal/cmd prompt and execute (check glpsol documentation for more options):

- Linux : `glpsol -m ESTD_model.mod -d ESTD_data.dat -d ESTD_12TD.dat -o ses_main.out`
- Mac OS X : `glpsol -m ESTD_model.mod -d ESTD_data.dat -d ESTD_12TD.dat -o ses_main.out`
- Windows : `glpsol.exe ESTD_model.mod -d ESTD_data.dat -d ESTD_12TD.dat -o ses_main.out`

Output

Output files are generated automatically in folder `./output`.

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