The European Electricity Market Model EMMA

Model Documentation

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Version 2021-01-07
Available online: https://github.com/emma-model/EMMA

Attribution should be given as follows: Hirth, L., Ruhnau, O., and Sgarlato, R. (2020). The European Electricity Market Model EMMA - Model Description.

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1 Overview

Summary. The Electricity Market Model EMMA is a techno-economic model of the integrated Northwestern European power system. It models investment, dispatch, and trade decisions, minimizing total costs subject to a large set of technical constraints. In economic terms, it is a partial equilibrium model of the wholesale electricity market with a focus on the supply side. It calculates scenario-based or long-term optima (equilibria) and estimates the corresponding capacity mix as well as hourly prices, generation, and cross-border trade for each market area. Technically, EMMA is a linear program, written in GAMS and solved by CPLEX on a desktop computer in about one hour. EMMA has been applied for several peer-reviewed publications to address a range of research questions. It is also used for consulting projects and policy assessment. EMMA is open-source: the model code and input data are freely available under the MIT Software License and the Create Commons BY-SA 4.0 License, respectively, and they can be downloaded from https://github.com/emma-model.

Objective function and decision variables. For a given hourly electricity demand, EMMA minimizes total system cost, i.e. the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs of generation, transmission, and storage assets (see Section 2 for details). Investment and generation are jointly optimized for one representative year. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and annualized investment and disinvestment in each technology, including wind and solar power. Core constraints constitute the energy balance, capacity limitations, the cogeneration of heat, and the provision of ancillary services. Decision variables and constraints are discussed in detail in the Subsections 2.2 to 2.5, grouped by topic. Subsection 2.6 offers an alternative, equivalent problem formulation.

Technologies. Generation and storage are modeled as 15 discrete technologies with continuous capacity:

(i) **Three variable renewable energy sources** with zero marginal costs - wind onshore, wind offshore, and solar photovoltaics. Hourly wind and solar generation are limited by exogenous generation profiles but can be curtailed at zero cost.

(ii) **Seven thermal technologies and a generic "load shedding" technology**. The thermal technologies include nuclear power, two types of coal-fired power plants (lignite and hard coal), two types of natural gas-fired power plants (combined cycle gas turbines, CCGT, and open cycle gas turbines, OCGT), bioenergy-fired power plants (aggregated biomass, biogas, and renewable waste) and coal-fired carbon capture and storage plants (CCS). These plants produce whenever the price is above their variable costs, except for bioenergy which is assumed to run constantly. For scenario-based analyses, up to three vintage classes with distinct conversion efficiencies are included per technology, in addition to one class per technology with newbuilt capacity. Load is shed if prices reach its opportunity cost (value of lost load).

(iii) **Four hydro power and storage technologies.** Run-off-the-river hydro generation is exogenous based on historical patterns. Hydro reservoirs are optimized considering turbine and reservoir capacity, natural inflow, and minimum generation constraints. Pumped hydro power and batteries are subject to power and energy capacity constraints. Table 1 provides an overview of all modeled technologies.

Table 1: Modeling of plant dispatch and investment

	Variable renewables	Thermal and load shedding	Hydro and storage
Fully endogenous (both dispatch and investment)	• Wind on land • Wind on sea • Solar PV (limited by generation profile)	• Nuclear • Lignite (vintages) • Hard coal (vin) • Hard coal with CCS • Natural gas CCGT (vin) • Natural gas OCGT (vin) • Load shedding (zero investment cost)	• Pumped hydro • Batteries
Dispatch endogenous, investment exogenous			• Reservoir hydro
Fully exogenous (both dispatch and investment)		• Bioenergy	• Run-off-the-river

Investment decision. EMMA can be used in different setups which we call "long-term equilibria" or "scenarios". The long-term equilibrium uses no legacy capacity ("green field"). Unlike the long-term equilibrium, the scenarios refer to specific years (2016, 2020, 2025, 2030, 2040) and hold specific assumptions on then-existing assets, fuel costs, and political constraints that may limit investment options (e.g. nuclear phase-out). The scenarios can be distinguished into "short-term" runs ("pure dispatch") and "mid-term" runs ("capacity expansion", "brown field"). In short-term runs, all capacity is fixed. In mid-term runs, existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments must recover their annualized capital costs from profits in the simulated year. Exceptions are run-off-the-river and reservoir hydro power as well es bioenergy, for which capacities are exogenously determined. For more details see Table 2 and Section 5.

Table 2: Scenario and long-term modeling

		Short-term scenario (2016, dispatch only)	Mid-term scenario (2025, 2030, capacity expansion)	Long-term equilibrium (green field)
Existing capacity	Generation and storage	Yes	Yes (disinvestment possible)	No
	Interconnection		Yes (no disinvestment)	
Investment	Generation and storage	No	Yes (with policy constraints)	Yes
	Interconnection		No	

For hydro reservoirs, run-off-the-river and bioenergy, existing (legacy) capacity is always included and (dis)investments are never allowed. Existing capacity varies by scenario year (e.g. 2016, 2025, 2030).

Spot price and capital costs recovery. Since one representative year is modeled, capital costs are included as annualized costs. The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices of an energy-only market with scarcity pricing. This guarantees that the zero-profit condition holds in the long-term equilibrium. In other words, there is no “missing money problem”. Note that in the engineering literature on power systems, the marginal cost of power generation is frequently referred to as “system lambda”.

Demand elasticity. Demand is exogenous and assumed to be perfectly price inelastic but for very high prices, in which case load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short timescales. While investment decisions take place over longer time scales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model runs.

Power system constraints. Two important classes of EMMA’s constraints concern combined heat and power generation and the provision of system services. Combined heat and power (CHP) generation is modeled as must-run generation. A certain share of the cogenerating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The generation from the remaining capacity of these technologies is freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of electric CHP capacity must remain constant. System service provision is a function of peak load and VRE capacity, and it is modeled as a must-run constraint for dispatchable generators. For details see Subsection 2.3 below.

Trade. Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model (long-term equilibrium) or based on scenarios. Endogenous interconnector investments are made only if they reduce overall system cost. Within regions, transmission capacity is assumed to be non-binding.

Cycling costs. The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior. This parametrization implies bids below variable costs for assigned base load technologies that tend to be less flexible.

Deterministic. The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not captured. Short-term uncertainty concerning VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the system service constraint, and by charging VRE generators balancing costs.

Geographical scope. EMMA can be applied to different geographical scopes. Data is readily available for Austria, Belgium, Switzerland, Czech Republic, Denmark, France, Great Britain, German, The Netherlands, Norway, Poland, and Sweden.

Solve time. The model is written in GAMS and solved by CPLEX using a primal simplex method. With five countries and 8760 times steps, the model consists of nearly two million equations and more than six million non-zero elements. The solution time on a personal computer is about half an hour per run with endogenous investment and a few minutes without investment.

Table 3: Model input and output

Model input (assumptions)	Model output (results)
• Installed capacity of generation, storage, interconnection (for scenario-based runs) • Investment costs and technical parameters of future generation, storage, interconnection • Fuel and CO_2 prices • Wind and solar generation potential (time series) • Electricity consumption (time series) • Power system constraints (balancing, CHP)	• (Dis-)investment in generation, storage, interconnection • Dispatch of generation, storage, interconnection • Cross-border trade • Electricity prices (day-ahead spot prices) • CO_2 emission • Market value of wind and solar energy • Profits/losses of generators

2 Model Equations

2.1 Total System Costs

Equation (1) is the model's objective function. The model minimizes the total system costs C with respect to a number of decision variables and technical constraints. Total system costs are the sum of fixed generation costs $C_{r,i,v}^{fix}$, variable generation costs $C_{t,r,i,v}^{var}$, and capital costs of storage C_{r}^{sto} and transmission $C_{r,rr}^{NTC}$ over all time steps t, regions r, generation technologies i, and vintage classes v (all notation is summarized in section 3 below):

$$
\begin{aligned}
C &= \sum_{r,i,v} C_{r,i,v}^{fix} + \sum_{t,r,i,v} C_{t,r,i,v}^{var} + \sum_{r} C_{r}^{sto} + \sum_{r,rr} C_{r,rr}^{NTC} \\
&= \sum_{r,i,v} \left(\hat{g}_{r,i,v}^{inv} \cdot c_{i}^{inv} + \left(\hat{g}_{r,i,v}^{0} - \hat{g}_{r,i,v}^{dec} + \hat{g}_{r,i,v}^{inv} \right) \cdot c_{i}^{qfix} \right) + \sum_{t,r,i,v} g_{t,r,i,v} \cdot c_{i,v}^{var} \\
&\quad + \sum_{r,l} \hat{s}_{r,l}^{inv} \cdot c_{l}^{power} + \hat{e}_{r,l}^{inv} \cdot c_{l}^{energy} + \sum_{r,rr} \hat{x}_{r,rr}^{inv} \cdot \phi_{r,rr} \cdot c^{NTC}
\end{aligned}
\qquad (1)
$$

Where $\hat{g}_{r,i,v}^{inv}$ is the investment in power generation capacity and $\hat{g}_{r,i,v}^{0}$ is the amount of existing capacity, of which $\hat{g}_{r,i,v}^{dec}$ is decommissioned, c_{i}^{inv} are annualized specific capital costs and c_{i}^{qfix} are yearly quasi-fixed costs such as operation and maintenance (O&M) costs. Balancing costs for VRE technologies are modeled as annualized fixed costs, such that they are not affecting bids and dispatch. Variable costs are the product of hourly generation $g_{t,r,i,v}$ with specific variable costs $c_{i,v}^{var}$ that include fuel, CO_2, and variable O&M costs. Investment in electricity storage capacity $\hat{s}_{r,l}^{inv}$ and $\hat{e}_{r,l}^{inv}$ comes at an annualized capital cost per unit of power c_{l}^{power} and per unit of energy c_{l}^{energy} but without variable costs. Transmission costs are a function of additional interconnector capacity $\hat{x}_{r,rr}^{inv}$, the geographic distance between markets $\phi_{r,rr}$, specific annualized ATC investment costs per MW and km c^{NTC}.

Upper-case C's denote absolute cost (EUR) while lower-case c's represent specific (per-unit) cost, such as EUR per MWh or EUR per MW. Hats indicate capacities that constrain the respective flow variables. Roman letters denote variables and Greek letters denote parameters. The two exceptions from this rule are initial capacities such as $\hat{g}_{r,i,v}^{0}$ that are denoted with the respective variable and zeros in superscripts, and specific costs c.

2.2 ENERGY BALANCE AND GENERATION CAPACITY CONSTRAINTS

The energy balance (2) is the central constraint of the model. Demand $\delta_{t,r}$ must be met by supply during every hour and in each region. Supply is the sum of generation $\mathrm{g}_{t,r,i,v}$ minus the sum of net exports $\mathrm{x}_{t,r,rr}$ plus the sum of storage output $\mathrm{s}^{o}_{t,r,l}$ minus storage in-feed $\mathrm{s}^{i}_{t,r,l}$. The hourly electricity price $p_{t,r}$ is defined as the shadow price of demand and has the unit €/MWh. The base price $\overline{p}_{r}$ is the time-weighted average price over all periods T. Note that (2) features an inequality, implying that supply can always be curtailed, thus the price does not become negative. The model can be interpreted as representing an energy-only market without capacity payments, and $p_{t,r}$ can be understood as the market-clearing zonal spot price as being implemented in many deregulated wholesale electricity pool markets. Since demand is perfectly price-inelastic, cost minimization is equivalent to welfare-maximization, and $p_{t,r}$ can also be interpreted as the marginal social benefit of electricity.

$$\delta_{t,r} \leq \sum_{i,v} \mathrm{g}_{t,r,i,v} + \sum_{l} \mathrm{s}^{o}_{t,r,l} - \mathrm{s}^{i}_{t,r,l} - \sum_{rr} \mathrm{x}_{t,r,rr} \qquad \forall\, t,r \tag{2}$$

$$p_{t,r} \equiv \frac{\partial C}{\partial \delta_{t,r}} \qquad \forall\, t,r$$

$$\overline{p}_{r} \equiv \frac{\sum_t p_{t,r}}{T} \qquad \forall\, r$$

Generation is constraint by available installed capacity. Equation (3) states the capacity constraint for the VRE technologies $j \subset i$, wind and solar power. Equation (4) is the constraint for dispatchable generators $k \subset i$, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Renewable generation is constraint by exogenous generation profiles $\varphi_{t,r,j}$ that captures both the variability of the underlying primary energy source as well as technical non-availability. Availability $\alpha_{t,r,k}$ is the technical availability of dispatchable technologies due to scheduled and unscheduled maintenance. The set v contains up to three elements for vintage classes of existing capacity, with $\hat{g}^{0}_{r,i,v} \geq 0$ and $\hat{g}^{inv}_{r,i,v} = 0$, and one element for new-built capacity, with $\hat{g}^{0}_{r,i,v} = 0$ and $\hat{g}^{inv}_{r,i,v} \geq 0$. Dispatchable capacity can be decommissioned endogenously via $\hat{g}^{dec}_{r,k,v}$ to save on quasi-fixed costs, while VRE capacity cannot. The decommissioning of dispatchable generators is limited by the existing capacity (5). Both generation and capacities are continuous variables. The value factors $f_{r,j}$ are defined as the average revenue of wind and solar relative to the base price.

$$g_{t,r,j,v} = \hat{g}_{r,j,v} \cdot \varphi_{t,r,j} = \left(\hat{g}^{0}_{r,j,v} + \hat{g}^{inv}_{r,j,v}\right) \cdot \varphi_{t,r,j} \qquad \forall\, t,r,j,v \tag{3}$$

$$g_{t,r,k,v} \leq \hat{g}_{r,k,v} \cdot \alpha_{t,r,k} = \left(\hat{g}^{0}_{r,k,v} - \hat{g}^{dec}_{r,k,v} + \hat{g}^{inv}_{r,k,v}\right) \cdot \alpha_{t,r,k} \qquad \forall\, t, r, k, v \tag{4}$$

$$\hat{g}^{dec}_{r,k,v} \leq \hat{g}^{0}_{r,k,v} \qquad \forall\, r, k, v \tag{5}$$

$$f_{r,j} \equiv \frac{\sum_t \varphi_{t,r,j}\, p_{t,r}}{\sum_t \varphi_{t,r,j}} / \overline{p}_{r} \qquad \forall\, r, j \in i$$

Minimizing (1) subject to constraint (5) and (6) implies that technologies generate if and only if the electricity price is equal or higher than their variable costs. It also implies the electricity price equals variable costs of a plant if the plant is generating and its capacity constraint is not binding. Finally, this formulation implies that if all capacities are endogenous, all technologies earn zero profits, which is the long-term economic equilibrium (for an analytical proof see Hirth and Ueckerdt (2013)).

2.3 Power System Inflexibilities

One of the aims of this model formulation is, while remaining parsimonious in notation, to include crucial constraints and inflexibilities of the power system, especially those that force generators to produce at prices below their variable costs (must-run constraints). Three types of such constraints are taken into account: CHP generation where heat demand limits flexibility, a must-run requirement for providers of ancillary services, and costs related to ramping, start-up, and shut-down of plants.

Combined heat and power

One of the major inflexibilities in European power systems is combined heat and power (CHP) generation, where heat and electricity is produced in one integrated process. This configuration can force plants to generate electricity, even if the electricity price is below their variable costs (e.g. when heat demand is high whilst residual load is low). The CHP must-run constraint (7) guarantees that the electricity generation of each of the five coal- or gas-fired CHP technologies $h \subset k$ does not fall below a minimum level $g^{min}_{t,r,h,v}$, derived from the heat demand. This minimum electricity generation is a function of the amount of electric CHP capacity of each technology and vintage $\hat{k}_{r,h,v}$, the minimum electricity generation profile $\psi^{min}_{t,r,h}$, and the technical availability $\alpha_{t,r,h}$. The minimum electricity generation profile is derived from the heat demand profile $\varphi^{heat}_{t,r}$, considering the design[1] power-to-heat ratios σ^{CHP}_{h} of different CHP types, namely backpressure turbines (BP), extraction-condensing turbines (EC), and exhaust

[1] The operational power-to-heat ratio can be larger than the design power-to-heat ratio for extraction-condensing turbines and exhaust heat recovery.

heat recovery (EH), which are weighted by their technology-specific shares in electric capacity χ_h^{CHP}. The heat demand profile is based on ambient temperature and captures the distribution of heat demand over time, relative to the peak demand. The equation (8) accounts for CHP constraints on the maximum power generation by $g_{t,r,h,v}^{max}$. The maximum generation is a function of the amount of CHP capacity of each technology $\hat{k}_{r,h,v}$,the maximum electricity generation profile $\psi_{t,r,h}^{max}$, the non-CHP capacity $\hat{g}_{r,h,v} - \hat{k}_{r,h,v}$, and the technical availability $\alpha_{t,r,h}$. The maximum electricity generation profile captures the characteristics of the different CHP types: the maximum electricity generation of backpressure turbines is proportional to the heat production, according to the fixed power-to-heat ratio σ_h^{BP}; the maximum power production of extraction-condensing turbines is inversely proportional to the heat production, according to the power-loss coefficient β_h^{EC}; and exhaust heat recovery has negligible implications for the maximum power output. The operational constraints for backpressure and extraction-condensing turbines as well as a combination of these are illustrated in Figure 1.

$$g_{t,r,h,v} \geq g_{t,r,h,v}^{min} = \hat{k}_{r,h,v} \cdot \psi_{t,r,h}^{min} \cdot \alpha_{t,r,h} \qquad \forall\, t,r,h,v \qquad (6)$$

where:

$$\psi_{t,r,h}^{min} = \left(\chi_h^{BP} \cdot \sigma_h^{BP} + \chi_h^{EC} \cdot \sigma_h^{EC} + \chi_h^{EH} \cdot \sigma_h^{EH}\right) \cdot \varphi_{t,r}^{heat}$$

$$g_{t,r,h,v} \leq g_{t,r,h,v}^{max} = \left(\hat{k}_{r,h,v} \cdot \psi_{t,r,h}^{max} + \left(\hat{g}_{r,h,v} - \hat{k}_{r,h,v}\right)\right) \alpha_{t,r,h} \qquad \forall\, t,r,h,v \qquad (7)$$

where:

$$\psi_{t,r,h}^{max} = \chi_h^{BP} \cdot \sigma_h^{BP} \cdot \varphi_{t,r}^{heat} + \chi_h^{EC} \cdot \left(1 - \beta_h^{EC} \cdot \varphi_{t,r}^{heat}\right) + \chi_h^{EH}$$

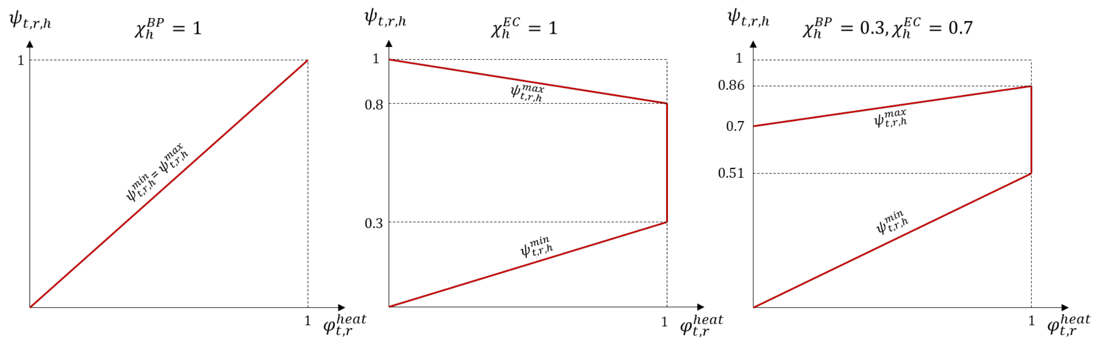

Figure 1: Operational CHP constraints for backpressure turbines (left), extraction condensing turbines (center), and a combination of these (right).

CHP investments $\hat{k}_{r,h,v}^{inv}$ as well as disinvestments $\hat{k}_{r,h,v}^{dec}$ are possible (8), but the resulting CHP capacity, investments, and disinvestments must be equal or smaller than the corresponding total values for every technology and vintage (9) to (11). Furthermore, the current total amount of CHP capacity in each region γ_r is not allowed to decrease (12). Taken together, (8) to (14) feature fuel switching in the CHP sector, but do not allow for a reduction of the total installed electric CHP capacity. For both the generation constraints (6) and (7) as well as the capacity constraint (12) one can derive shadow prices $p_{t,r}^{CHPgene}$ (€/MWh) and $p_r^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heating energy and capacity, respectively.

$$\hat{k}_{r,h,v} = \hat{k}_{r,h,v}^{0} - \hat{k}_{r,h,v}^{dec} + \hat{k}_{r,h,v}^{inv} \qquad \forall\, r,h,v \qquad (8)$$

$$\hat{k}_{r,h,v} \leq \hat{g}_{r,h,v} \qquad \forall\, r,h,v \qquad (9)$$

$$\hat{k}_{r,h,v}^{inv} \leq \hat{g}_{r,h,v}^{inv} \qquad \forall\, r,h,v \qquad (10)$$

$$\hat{k}_{r,h,v}^{dec} \leq \hat{g}_{r,h,v}^{dec} \qquad \forall\, r,h,v \qquad (11)$$

$$\sum_{h,v} \hat{k}_{r,h,v} \geq \gamma_r \qquad \forall\, r \qquad (12)$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial \varphi_{t,r}^{heat}} \qquad \forall\, t,r$$

$$p_{r}^{CHPcapa} \equiv \frac{\partial C}{\partial \gamma_r} \qquad \forall\, r$$

Ancillary services

Electricity systems require a range of measures to ensure stable and secure operations. These measures are called ancillary services. Many ancillary services can only be supplied by generators while producing electricity, such as the provision of regulating power or reactive power (voltage support). Thus, a supplier that commits to provide such services over a certain time (typically much longer than the delivery periods on the spot market) has to produce electricity even if the spot prices falls below its variable costs. In this model, ancillary service provision is implemented as a must-run constraint on the spinning reserves (13): an amount σ_r of dispatchable capacity must be in operation at any time. We set σ_r to 10% of peak load plus 5% of VRE capacity of each region (14), a calibration based on Hirth and Ziegenhagen (2015). Two observations were used to estimate this parameter. First, observed clearing prices can indicate when must-run constraints become binding: equilibrium prices dropping below the variable cost of base load plants for extended periods of time may indicate that must-run constraints are binding. Nicolosi (2012) reports that German power prices fell below zero at residual loads between 20-30 GW, about 25-40% of peak load. Second, FGH et al. (2012) provide a detailed study on must-run generation caused by system stability requirements, considering network security, short circuit power, voltage support, ramping, and regulating power. They find that the minimum generation requirement reaches 25 GW in Germany, about 32% of peak load. For details on the empirical calibration procedure see (2015).

In the model it is assumed that CHP generators cannot provide ancillary services, whereas pumped hydro storage can, either while pumping or while generating. For a region with a peak demand of 80 GW, 8 GW of dispatchable generators or storage must be producing at any moment. Note that a thermal capacity of 4 GW together with a pump capacity of 4 GW can fulfill this condition with a net zero effect on the energy balance. The shadow price of σ_r , $p_{t,r}^{AS}$, is defined as the price for ancillary services, with the unit €/KWa.

$$\sum_k g_{t,r,k} - \sum_h \hat{k}_{r,h} \cdot \psi_{t,r,h}^{min} \cdot \alpha_{t,r,h} + \sum_l \mathrm{s}_{t,r,l}^{o} + \mathrm{s}_{t,r,l}^{i} \geq \sigma_r \qquad \forall\, t,r \tag{13}$$

$$\sigma_r = 0.1 \cdot \max_t\left(d_{t,r}\right) + 0.05 \cdot \sum_{j,v} \hat{g}_{r,j,v}^{0} + \hat{g}_{r,j,v}^{inv} \qquad \forall\, r \tag{14}$$

$$p_r^{AS} \equiv \frac{\partial C}{\partial \sigma_r} \qquad \forall\, r$$

Ramping

Finally, thermal power plants have limits to their operational flexibility, even if they do not produce goods other than electricity. Restrictions on temperature gradients within boilers, turbines, and fuel gas treatment facilities and laws of thermodynamics imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly or constraint. In the case of nuclear power plants nuclear reactions related to Xenon-135 set further limits on ramping and down time. These various non-linear, status-dependent, and intertemporal constraints are proxied in the present framework by forcing certain generators to tolerate a predefined threshold of negative contribution margins before shutting down. This is implemented as a “run-through premium” for nuclear, lignite, and hard coal plants. For example, the variable cost for a nuclear plant is reduced by 10 €/MWh. In order not to distort its full cost, fixed costs are duly increased by 87,600 €/MWa.

2.4 FLEXIBILITY OPTIONS

The model aims to not only capture the major inflexibilities of existing power technologies, but also to model important flexibility options. Electricity storage, hydro reservoirs, and transmission expansion can make electricity systems more flexible. These options are discussed next.

Storage

The model includes a set of storage technologies l, which differ in terms of cycle efficiency and investment costs. The amount of energy stored at a certain hour $e_{t,r,l}$ is last hour's amount minus output $\mathrm{s}^{o}_{t,r,l}$ plus in-feed $\mathrm{s}^{i}_{t,r,l}$ (15), accounting for the storage cycle efficiency η_l . Both input and output are limited by the power capacity $\hat{\mathrm{s}}_{r,l}$ (16). The amount of stored energy is constrained by the storage energy capacity $\hat{e}_{r,l}$ (17). The only costs related to storage are capital costs in the case of new investments, which we split into a power component $\hat{\mathrm{s}}^{inv}_{r,l}$ and an energy component $\hat{e}^{inv}_{r,l}$. The energy-per-power ratio, also referred to as "storage duration", must be at least one hour (18). We are not considering decommissioning of storage.

$$e_{t,r,l} = e_{t-1,r,l} - \frac{\mathrm{s}^{o}_{t,r,l}}{\sqrt{\eta_l}} + \sqrt{\eta_l} \cdot \mathrm{s}^{i}_{t,r,l} \qquad \forall t,r,l \qquad (15)$$

$$\mathrm{s}^{i}_{t,r,l} + \mathrm{s}^{o}_{t,r,l} \leq \hat{\mathrm{s}}_{r,l} = \hat{\mathrm{s}}^{0}_{r,l} + \hat{\mathrm{s}}^{inv}_{r,l} \qquad \forall t,r,l \qquad (16)$$

$$e_{t,r,l} \leq \hat{e}_{r,l} = \hat{e}^{0}_{r,l} + \hat{e}^{inv}_{r,l} \qquad \forall t,r,l \qquad (17)$$

$$\hat{e}^{inv}_{r,l} \geq \hat{\mathrm{s}}^{inv}_{r,l} \qquad \forall r,l \qquad (18)$$

Hydro reservoirs

Hydro reservoirs are modeled as a generation technology subject to special constraints. First, hydro generation $g^{hydr}_{t,r}$ depends on an exogenous inflow $\varphi^{hydr}_{t,r}$, which can be stored in a reservoir affecting the reservoir level $e^{hydr}_{t,r}$ (19). Generation cannot exceed installed capacity (20) and there may be a required minimum generation (21). As for storage technologies, the reservoir level is limited (22). Note that we do not model endogenous investment and decommissioning of hydro reservoirs.

$$e^{hydr}_{t,r} = e^{hydr}_{t-1,r} - g^{hydr}_{t,r} + \varphi^{hydr}_{t,r} \qquad \forall t,r \qquad (19)$$

$$g^{hydr}_{t,r} \leq \hat{g}^{hydr}_{r} = \hat{g}^{0,hydr}_{r} \qquad \forall t,r \qquad (20)$$

$$g^{hydr}_{t,r} \geq \hat{g}^{hydr}_{r} \cdot \varphi^{hydr,min}_{t,r} \qquad \forall t,r \qquad (21)$$

$$e^{hydr}_{t,r} \leq \hat{e}^{hydr}_{r} = \hat{e}^{0,hydr}_{r} \qquad \forall t,r \qquad (22)$$

Interconnectors

Within regions, the model abstracts from grid constraints, applying a copperplate assumption. Between regions, transmission capacity is constrained by net transfer capacities (ATCs). Ignoring transmission losses, the net export $\mathrm{x}_{t,r,rr}$ from r to rr equals net imports from rr to r (19). Equations (20) and (21) constraint electricity trade to the sum of existing interconnector capacity $\hat{x}^0_{r,rr}$ and new interconnector investments $\hat{x}^{inv}_{r,rr}$. Equation (22) ensures lines can be used in both directions. Recall from (1) that interconnector investments have fixed specific investment costs, which excluded economies of scale as well as non-linear transmission costs due to the nature of meshed HVAC systems. The distance between markets $\delta_{t,r}$ is measured between the geographical centers of regions.

$$\mathrm{x}_{t,r,rr} = -\mathrm{x}_{t,r,rr} \qquad \forall t, r, rr \qquad (23)$$

$$\mathrm{x}_{t,r,rr} \leq \hat{x}^0_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t, r, rr \qquad (24)$$

$$\mathrm{x}_{t,rr,r} \leq \hat{x}^0_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t, r, rr \qquad (25)$$

$$\hat{x}^{inv}_{rr,r} = \hat{x}^{inv}_{r,rr} \qquad \forall t, r, rr \qquad (26)$$

2.5 Balancing Costs

There are two ways how balancing costs are modelled: costs for reserving spinning reserves, and costs of activation. Spinning reserves are modelled as a reserve requirement as a function of peak load and installed VRE capacity. Activation costs are added as a cost mark-up on generation costs.

2.6 Alternative Problem Formulation

In short, the above cost minimization problem can be equivalently expressed as

$$\min C \qquad (27)$$

with respect to the investment and decommissioning variables $\hat{g}^{inv}_{r,i,v}$, $\hat{g}^{dec}_{r,i,v}$, $\hat{k}^{inv}_{r,h,v}$, $\hat{k}^{dec}_{r,h,v}$, $\hat{\mathrm{s}}^{inv}_{r,l}$, $\hat{e}^{inv}_{r,l}$, $\hat{x}^{inv}_{r,rr}$, the dispatch variables $g_{t,r,i,v}$, $\mathrm{s}^{i}_{t,r,l}$, $\mathrm{s}^{o}_{t,r,l}$, and the trade variable $x_{t,r,rr}$ subject to the constraints (2) – (20). Minimization gives optimal values of the decision variables and the shadow prices $p_{t,r}$, $p^{CHPgene}_{t,r}$, $p^{CHPcapa}_{r}$, p^{AS}_{r} and their aggregates $\overline{p}_{r}$, $f_{r,j}$.

3 Notation

Table 4 summarizes the notation of this documentation and the GAMS code. For the latter, we use the convention that parameters are specified in lowercase letters while variables are denoted in UPPERCASE. Parameters are grouped according to their role in the optimization:

- Input parameters carry the prefix “i_”. They are used in calculations prior to the optimizing and to extract data from Excel sheets.
- Model parameters do not carry any prefix. They appear in the equations that constitute the problem.
- Output parameters carry the prefix “o_”. They are used for calculations based on optimal value, e.g. market value of wind energy derived from the electricity price, itself derived from the shadow price of demand.

Table 4: Notation

Indices (sets)			
Name	**Documentation**	**GAMS code**	**Elements**
Time step (number of time steps)	$t \in T$	t	1, 2, 3, … 8760
Region	$r, rr \in R$	r, rr	AUT, BEL, CHE, CZE, DNK, FRA, GBR, GER, NLD, NOR, POL, SWE
All technologies		alltec	nucl, lign, coal, cCCS, CCGT, cCCS, CCH2, OCGT, shed, wion, wiof, solar, hydr, PHS, batr, ror, bio
Technologies with endogenous dispatch		tec_mod	nucl, lign, coal, cCCS, CCGT, cCCS, CCH2, OCGT, shed, wion, wiof, solar, hydr, PHS, batr
Technologies with exogenous dispatch		tec_exo	ror, bio
Generation technologies	$i \in I$	tec_gen (tec_inv without hydr)	nucl, lign, coal, cCCS, CCGT, cCCS, CCH2, OCGT, shed, wion, wiof, solar, hydr
Storage technologies	$l \in L$	tec_sto	PHS, batr
VRE technologies	$j \in J$	tec_vre	wion, wiof, solar
Thermal technologies	$k \in K$	tec_thm	nucl, lign, coal, cCCS, CCGT, cCCS, CCH2, OCGT, shed
CHP technologies	$h \in H$	tec_chp	lign, coal, cCCS, CCGT, cCCS, CCH2, OCGT, shed
Vintages	$v \in V$	allvin	/1, 2, 3, new/

Capacity and generation					
	Total capacity (variable)	Initial / existing capacity (parameter)	Added capacity (variable)	Decommissioned capacity (variable)	Corresponding dispatch variable (variable)
Generation	$\hat{g}_{r,i,v}$	$\hat{g}^{0}_{r,i,v}$	$\hat{g}^{inv}_{r,i,v}$	$\hat{g}^{dec}_{r,i,v}$	$g_{t,r,i,v}$
Export / import	$\hat{x}_{r,rr}$	$\hat{x}^{0}_{r,rr}$	$\hat{x}^{inv}_{r,rr}$		$\mathrm{x}_{t,r,rr}$
Storage volume	$\hat{e}_{r,l}$	$\hat{e}^{0}_{r,l}$	$\hat{e}^{inv}_{r,l}$		$v_{t,r,l}$
Storage in- / output	$\hat{\mathrm{s}}_{r}$	$\hat{\mathrm{s}}^{0}_{r}$	$\hat{\mathrm{s}}^{inv}_{r}$		$\mathrm{s}^{o}_{t,r}$, $\mathrm{s}^{i}_{t,r}$
CHP capacity	$\hat{k}_{r,h,v}$	$\hat{k}^{0}_{r,h,v}$	$\hat{k}^{inv}_{r,h,v}$	$\hat{k}^{dec}_{r,h,v}$	-

Cost parameters	Documentation	GAMS	Unit
Capital costs for power plants (specific, annualized)	c^{inv}_{i}	cost_inv(alltec)	$\frac{M€}{GW \cdot a} = \frac{€}{kW \cdot a}$
Quasi-fixed (O&M) costs for power plants (specific, annualized)	c^{qfix}_{i}	cost_qfix(tec_inv)	$\frac{M€}{GW \cdot a} = \frac{€}{kW \cdot a}$
Variable costs for power plants	$c^{var}_{i,v}$	cost_var(tec_thm)	$\frac{M€}{GWh} = \frac{€}{kWh}$
Storage cost, power component (specific, annualized)	c^{power}_{l}	cost_fix(tec_sto)	$\frac{M€}{GWh \cdot a} = \frac{€}{kWh \cdot a}$
Storage cost, energy component (specific, annualized)	c^{energy}_{l}	cost_energy(tec_sto)	$\frac{M€}{GW \cdot a} = \frac{€}{kW \cdot a}$
Interconnector capital costs (specific, annualized)	c^{NTC}	cost_ntc	$\frac{M€}{GW_{NTC} \cdot km \cdot a}$

Other key parameters	Documentation	GAMS	Unit
Demand	$\delta_{t,r}$	loa(t,r)	GW
Distance between markets	$\phi_{r,rr}$	km(r,rr)	km
Storage cycle efficiency	η_{l}	eff(tec_sto)	1
VRE generation profile	$\varphi_{t,r,j}$	profile(t,tec_vre,r)	1
Heat demand profile	$\varphi^{heat}_{t,r}$	profile(t,"CHP",r)	1
Hydro reservoir inflow	$\varphi^{hydr}_{t,r}$	Inflow(t,r)	1
CHP minimum electricity generation (analogous for maximum)	$\psi^{min}_{t,r,h}$	CHPprofile (t,tec_chp,"min",r)	1
Technical availability of thermal plants	$\alpha_{t,r,k}$	avail(t,tec_thm,r)	1
Minimal thermal generation	σ_{r}	as(r)	GW

4 Input data

The input data comprises hourly time series for demand and renewable generation, as well as data on costs and fuel prices, on costs and fuel prices, the existing power system, and scalar data on costs, fuel prices, the existing power system, and on yearly demand and generation volumes. Table 5 summarizes key parameters and sources, which are further described below.

Table 5: Key parameters and sources.

Topic	Parameter	Source
Time series	Hourly electricity load	Open Power System Data (2019): Data Package Time Series. Version 2019-06-05. https://doi.org/10.25832/time_series/2019-06-05
	Historic hourly electricity generation from wind and solar energy	Open Power System Data (2019): Data Package Time Series. Version 2019-06-05. https://doi.org/10.25832/time_series/2019-06-05
	Future hourly electricity generation from wind and solar energy	European Commission (2019): METIS scripts and data. https://ec.europa.eu/energy/data-analysis/energy-modelling/metis/metis-scripts-and-data_en
Costs	Investment and fixed and variable operational costs	Tractebel, Ecofys, E3-Modelling (2018): Technology pathways in decarbonization scenarios. Available at: https://asset-ec.eu/home/advanced-system-studies/cluster-3/technology-pathways-in-decarbonisation-scenarios/
Fuel prices	Gas Prices	International Monetary Fund (2020): Commodity Data Portal. Available at: https://www.imf.org/en/Research/commodity-prices
	Coal Prices	Quandl (2020): Coal Prices. $US per Tonne. Northwest Europe Marker Price. Available at: https://www.quandl.com/data/BP/COAL_PRICES
	Prices of emission certificates under the EU emission trading schemes	ICAP (2020): Allowance Price Explorer. Available at: https://icapcarbonaction.com/en/ets-prices
Existing power system	Generation capacity	Open Power System Data (2019). Data Package Conventional power plants. https://doi.org/10.25832/conventional_power_plants/ Open Power System Data (2019). Data Package National generation capacity. https://doi.org/10.25832/national_generation_capacity/
	CHP capacity	Eurostat (2015): CHP capacity data according type of generation. https://ec.europa.eu/eurostat/web/energy/data
	Net transfer capacity	Agency for the Cooperation of Energy Regulators (ACER) (2015-2019): ACER Market Monitoring Report – Electricity. http://www.acer.europa.eu/Official_documents/Publications/Pages/Publication.aspx
Yearly volumes	Yearly electricity demand	IEA (2020): Monthly Electricity Statistics. Available at: https://www.iea.org/reports/monthly-oecd-electricity-statistics
	Yearly electricity generation by fuel (for technologies with exogenous dispatch)	ENTSO-E (2019): Power Statistics. Monthly Domestic Values. Available at: https://www.entsoe.eu/data/power-stats/
	Yearly (physical) net electricity exports with non-modeled countries	Eurostat (2020): Exports. nrg_te_eh. Available at: https://ec.europa.eu/eurostat/estat-navtree-portlet-prod/BulkDownloadListing?sort=1&dir=data

Time series

Each region's electricity demand, heat demand, and wind and solar generation are described using hourly information. Time series are available for different weather years with specific temporal and spatial correlation of each parameter as well as between parameters. These correlations are crucial to estimate value factors and marginal benefits of VRE accurately. Load and historic generation data were taken from the Open Power System Data Platform. Heat profiles are based on ambient temperature. Future renewable profiles are used from the METIS project.

Cost parameters

Historic fuel prices are retrieved from the sources given in Table 5. All other cost parameters and the conversion efficiency of new power plants, which affects their variable cost, are taken from De Vita et al. (2018). This report provides cost estimates for different time horizons, of which we use 2050 values for long-term runs and 2015/2020 values for other scenarios. Furthermore, this report provides storage cost in €/MWh, which we distinguish into €/MW and €/MWh assuming a 1:1 ratio and a 10h duration for pumped hydro storage and a 1:2 ratio as well as a 1h duration for batteries. Flexible technologies, including OCGT and storage, are assumed to earn 30% of their investment cost from other markets (e.g. balancing energy). The cost of load shedding is set to 1,000 €/MWh, which can be interpreted as value of lost load. If not stated otherwise, a default interest rate of 7% is used for all investments, including generation, transmission, and storage. Transmission investment costs are 3.4 million Euro per GW NTC capacity and km. Balancing cost are set to 1 €/MWh for wind and 1.5 €/MWh für solar power, which is somewhat higher than reported by Madlener and Ruhnau (2021) for the intraday market only.

Existing power system

For short- and medium-term model runs, data on the existing power system serves as an input. For the existing generation capacity, the plant-level data is assigned to different vintage classes based on their commissioning date, and the remaining national generation capacity is equally distributed to vintage classes. Note that existing oil capacity (less than 1% of total generation within the full EMMA geo-scope according to ENTSO-E Power Statistics) is included with the oldest OCGT vintage. Brownfield simulations assume a 50-years lifetime of existing power plants to calculate the then-existing capacities. The CHP capacity by technology is taken from Eurostat and assigned to vintages proportionally to their overall capacity. The net transfer capacity is taken from ACER.

Yearly volumes

Yearly volumes are used to scale demand time series, exogenous generation (bioenergy, hydro run-off-river, and reservoir inflow), as well as for net exports to non-modeled countries.

5 Investment and Model Horizon

Welfare-optimality can be defined under different assumptions about the capital stock. Given electricity is a very capital-intensive industry, this makes a large difference. One option is to take the existing generation and transmission infrastructure as given and disregard any changes to that. Thus, the optimization problem reduces to dispatch. In economics jargon this is the *short-term* perspective. Another possibility is to disregard any existing infrastructure and optimize the electricity system "from scratch" as if all capacity was green-field investment. This is the *long-term* perspective. Finally, one can take some existing infrastructure as given, but allow for endogenous investments and disinvestments. In such a framework, capital costs for existing capacities are sunk and thus disregarded in the optimization, but endogenous changes to the capital stock are possible. This can be labeled the *medium term*. For the short-, mid-, and long-term framework corresponding welfare-optima exist, which are, for the assumption of perfect markets, identical to the corresponding market equilibria. Note that the expressions short term and long term are *not* used to distinguish the time scale on which dispatch and investment decisions take place but refer to the way the capital stock is treated.

Short-, medium-, and long-term frameworks are analytical concepts that of course never apply perfectly to a real-world situation. There are several factors that determine which is appropriate for a certain time horizon: the short term is limited by the time it takes to plan and construct new power plants, which might be on average three years for gas and coal plants. The borderline between mid and long term is less clearly drawn: the long term is more relevant, if large amounts of capacity are added such that the capacity mix approaches the long-term optimum. Thus any factor that makes capacity more scarce makes the long term a more relevant framework: if the remaining life-time of existing capacity is short, demand growth strong, or policy or other shocks induce a lot of new investments, the long-term equilibrium will be reached quickly. Since power plants typically have a life-time of 20-60 years, and in many Northwestern European countries electricity demand is expected to grow very slowly or even decline, we believe a mid-term perspective is an appropriate framework to analyze a time horizons of 3 to 15 years, and a long-term perspective for longer time horizons.

6 Model Limitations

The model is highly stylized and has important limitations when it comes to the representation of detailed technological constraints. An important example includes the absence of demand response (apart from load shedding), which would help to integrate VRE generation. Ignoring these flexibility resources leads to a downward bias of VRE market values.

Other important limitations to the model include the absence of constraints related to unit commitment of power plants such as limits on minimum load, minimum up-time, minimum down-time, ramping and start-up costs, and part-load efficiencies; the aggregation of power plants into vintages; not accounting for market power or other market imperfections; ignoring all externalities of generation and transmission other than carbon; ignoring uncertainty; absence of any exogenous or endogenous technological learning or any other kind of path dependency; not accounting for VRE resource constraints; ignoring grid constraints at the transmission and distribution level; any effects related to lumpiness or economies of scale of investments.

Table 6, updated from Hirth (2016), summarizes model features and limitations.

Table 6: Model features that are likely to significantly impact the wind market value

Features modeled	Features not modeled
• High resolution (hourly granularity) • Long-term adjustment of capacity mix • Realistic (historical) wind power, hydro inflow pattern, and load profiles • System service provision • Combined heat and power plants • Hydro reservoirs • Pumped hydro storage • Interconnected power system (imports and exports) • Cost-optimal investment in interconnector capacity • Thermal plant start-up costs • Curtailment of wind power • Balancing power requirements	*Impact likely to be positive for VRE (including these features would change value factor upwards)* • Price-elastic electricity demand, e.g. from industry, electrical heating, or e-mobility *Impact likely to be negative for VRE (including these features would change value factor downwards)* • Internal transmission constraints/ bidding areas • More detailed modeling of hydro constraints (cascades, icing, environmental restrictions) • Shorter dispatch intervals (15 min) • Market power of non-wind generators • Ramping constraints of thermal plants • Year-to-year variability of wind and hydro capacity factors, and correlation among these • Business cycles / overinvestments • Imperfect foresight

The impact of the features not modeled (right column) is based on personal assessment.

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