The European Electricity Market Model EMMA

Model documentation

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1. Overview

Summary. The open-source Electricity Market Model EMMA is a techno-economic model of the integrated Northwestern European power system. It models both dispatch of and investment in power plants, minimizing total costs with respect to investment, production and trade decisions 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 short-term 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 with six million non-zero variables. It is written in GAMS, and solved by Cplex on a desktop computer in about ten minutes. EMMA has been used for eight peer-reviewed publications to address a range of research questions[1] (for a full list of references see section 13). It is also used for consulting projects. EMMA is open-source: the model code as well as all input parameters and the model documentation are freely available to the public under the Creative Commons BY-SA 3.0 license and can be downloaded from http://neon-energie.de/EMMA.

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

[1] Hirth (2016a), Hirth (2016b), Hirth & Steckel (2016), Hirth & Müller (2016), Hirth (2015a), Hirth (2015b), Hirth & Ueckerdt (2013), Hirth (2013).

of generation, transmission, and storage assets. 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. The important constraints relate to energy balance, capacity limitations, and the provision of district heat and ancillary services.

Generation technologies. Generation is modeled as twelve discrete technologies with continuous capacity: (i) Two variable renewable energy sources with zero marginal costs – wind and solar power. Hourly wind and solar generation is limited by exogenous generation profiles, but can be curtailed at zero cost. (ii) Six thermal technologies with economic dispatch – 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), and lignite-fired carbon capture and storage plants (CCS). Dispatchable plants produce whenever the price is above their variable costs. (iii) A generic "load shedding" technology. Load is shed if prices reach its opportunity cost. (iv) Three hydro power technologies: run-off-the-river hydro power, hydro reservoir power, and pumped hydro storage; run-off-the-river hydro power is exogenous, while the other hydro technologies are optimized endogenously under turbine, pumping, inventory, inflow, and minimum generation constraints. Cost data are presented in section 10.

Investment decision. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments have to recover their annualized capital costs from short-term profits. EMMA can be operated in three different modes: a "short-term" pure dispatch model without investment, a "mid-term" investment expansion model, or a "long-term" green-field optimization. The first two modes account for existing assets, while the latter starts from scratch. The one exception is hydro reservoir power, which is not available for investments, since site availability limits capacity expansion in practice. For more details see section 11.

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". In the electric engineering power system literature, the marginal costs of power generation is often labeled "system lambda", because they are derived from the shadow price of one of the constraints of an optimization model.

Demand elasticity. Demand is exogenous and assumed to be perfectly price inelastic at all prices but the very highest, when 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. EMMA accounts for a large number of power system constraints. Two important classes of 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 remaining capacity of these technologies can be freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity is fixed. System service provision is modeled as a must-run constraints for dispatchable generators that is a function of peak load and VRE capacity. For details see section 4 unterhalb. Hirth (2015) and Hirth & Ziegenhagen (2015) provide background on the calibration procedure.

Trade. Cross-border trade is endogenous and limited by available transfer capacities (ATCs). Investments in interconnector capacity are endogenous to the model. As a direct consequence of our price modeling, interconnector investments are profitable if and only if they are socially beneficial. 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. An electricity price is bid below the variable costs of assigned base load plants in order to avoid ramping and start-ups.

Deterministic. The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not modeled. 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 is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, France, Sweden, and Norway. Earlier model versions did not include Nordic countries. In an alternative setup, it was calibrated to the Chinese province of Shandong.

2. Total System Costs

Equation (1) is the model's objective function. The model minimizes total system costs C with respect to a large number of decision variables and technical constraints. Total system costs are the sum of fixed generation costs $c_{r,i}^{fix}$, variable generation costs $C_{t,r,i}^{var}$, and capital costs of storage C_r^{sto} and transmission $C_{r,rr}^{ATC}$ over all time steps t, regions r, and generation technologies i (all notation is summarized in section 12 below):

$$C = \sum_{r,i} C_{r,i}^{fix} + \sum_{t,r,i} C_{t,r,i}^{var} + \sum_{r} C_r^{sto} + \sum_{r,rr} C_{r,rr}^{ATC}$$

$$= \sum_{r,i} \left(\hat{g}_{r,i}^{inv} \cdot c_i^{inv} + \left(\hat{g}_{r,i}^{0} + \hat{g}_{r,i}^{inv} \right) \cdot c_i^{qfix} \right) + \sum_{t,r,i} g_{t,r,i} \cdot c_i^{var} + \sum_{r} \hat{\mathrm{s}}_r^{inv} \cdot c^{sto} + \sum_{r,rr} \hat{x}_{r,rr}^{inv} \cdot \phi_{r,rr} \cdot \mathrm{c}^{ATC} \quad (1)$$

Where $\hat{g}_{r,i}^{inv}$ is the investments in generation capacity and $\hat{g}_{r,i}^{0}$ are existing capacities, 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 also modeled for as fixed costs, such that they are not affecting bids. Variable costs are the product of hourly generation $g_{t,r,i}$ with specific variable costs c_i^{inv} that include fuel, CO_2, and variable O&M costs. Investment in pumped hydro storage capacity $\hat{\mathrm{s}}_r^{inv}$ comes at an annualized capital cost of c^{sto}but without variable costs. Transmission costs are a function of additional interconnector capacity $\hat{x}_{r,rr}^{inv}$, distance between markets $\phi_{r,rr}$, specific annualized ATC investment costs per MW and km c^{ATC}.

Upper-case C's denote absolute cost while lower-case c's represent specific (per-unit) cost. 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 $\hat{g}_{r,i}^{0}$ that are denoted with the respective variable and zeros in superscripts, and specific costs c.

3. Energy balance

The energy balance (2) is the central constraint of the model. Demand $\delta_{t,r}$ has to be met by supply during every hour and in each region. Supply is the sum of generation $\mathrm{g}_{t,r,i}$ minus the sum of net exports $\mathrm{x}_{t,r,rr}$ plus storage output $\mathrm{s}_{t,r}^{o}$ minus storage in-feed $\mathrm{s}_{t,r}^{i}$. Storage cycle efficiency is given by η. 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.

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

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

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

Generation is constraint by available installed capacity. Equation (3) states the capacity constraint for the VRE technologies j, wind and solar power. Equation (4) is the constraint for dispatchable generators k, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Note that technology aggregates are modeled, not individual blocks or plants. 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. Dispatchable capacity can be decommissioned endogenously via $\hat{g}_{r,k}^{dec}$ to save on quasi-fixed costs, while VRE capacity cannot. 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.

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

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

$$f_{r,j} \equiv \frac{\sum_t \varphi_{t,r,j}\, p_{t,r}}{\sum_t \varphi_{t,r,j}} / \overline{p}_{r} \qquad \forall\, r,j \in i \tag{5}$$

Minimizing (1) subject to constraint (3) 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 the 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 & Ueckerdt 2013).

4. Power System Inflexibilities

One of the aims of this model formulation is, while remaining parsimonious in notation, to include crucial constraint 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.

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. High demand for heat forces plants to stay online and generate electricity, even if the electricity price is below variable costs. The CHP must-run constraint (5) guarantees that generation of each CHP technology h, which are the five coal- or gas-fired technologies, does not drop below the minimal level determined by heat demand $g_{t,r,h}^{min}$. Minimum generation is a function of the amount of CHP capacity of each technology $\hat{k}_{r,h}^{inv}$ and the heat profile $\varphi_{t,r,chp}$. The profile is based on ambient temperature and captures the distribution of heat demand over time. CHP capacity of a technology has to be equal or smaller than total capacity of that technology (6). Furthermore, the current total amount of CHP capacity in each region γ_r is not allowed to decrease (7). Investments in CHP capacity $\hat{k}_{r,h}^{inv}$ as well as decommissioning of CHP $\hat{k}_{r,h}^{dec}$ are possible (8), but only to the extent that total power plant investments and disinvestments take place (9), (10). Taken together, (6) – (10) allow fuel switch in the CHP sector, but do not allow reducing total CHP capacity. For both the generation constraint (5) and the capacity constraint (7) one can derive shadow prices $p_{t,r,h}^{CHPgene}$ (€/MWh) and $p_{t,r,h}^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heating, energy and capacity, respectively.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = \hat{k}_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,k} \qquad \forall\, t,r,h \in m \qquad (6)$$

$$\hat{k}_{r,h} \leq \hat{g}_{r,h} \qquad \forall\, r,h \qquad (7)$$

$$\sum_h \hat{k}_{r,h} \geq \gamma_r = \sum_h \hat{k}_{r,h}^0 \qquad \forall\, r \qquad (8)$$

$$\hat{k}_{r,h} = \hat{k}_{r,h}^0 + \hat{k}_{r,h}^{inv} + \hat{k}_{r,h}^{dec} \qquad \forall\, r,h \qquad (9)$$

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

$$\hat{k}_{r,h}^{dec} \geq \hat{g}_{r,h}^{dec} \qquad \forall\, r,h$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial\, g_{t,r,h}^{min}} \qquad \forall\, t,r$$

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

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 or are typically supplied by generators while producing electricity, such as the provision of regulating power or reactive power (voltage support). Thus, a supplier that committed 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 of spinning reserves (11): an amount σ_r of dispatchable capacity has to be in operation at any time. We set σ_r to 10% of peak load plus 5% of VRE capacity of each region, a calibration based on Hirth & Ziegenhagen (2013). Two pieces of information were used when setting this parameter. First, market prices indicate when must-run constraints become binding: if equilibrium prices drop below the variable cost of base load plants for extended periods of time, must-run constraints are apparently 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 due to system stability, taking into account network security, short circuit power, voltage support, ramping, and regulating power. They find minimum generation up to 25 GW in Germany, about 32% of peak load. For details on the empirical calibration procedure see Hirth (2015).

In the model it is assumed that CHP generators cannot provide ancillary services, but pumped hydro storage can provide them while either pumping or generating. For a region with a peak demand of 80 GW, at any moment 16 GW of dispatchable generators or storage have to be online. Note that thermal capacity of 8 GW together with a pump capacity of 8 GW can fulfill this condition without net generation. The shadow price of σ_r , $p_{t,r}^{AS}$, is defined as the price of ancillary services, with the unit €/KW$_{\text{online}}$a.

$$\sum_h g_{t,r,h} - \sum_h \hat{k}_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,k} + \eta \cdot \mathrm{s}_{t,r}^{i} \geq \sigma_r \qquad \forall\, t,r \tag{11}$$

$$\sigma_r = 0.1 \cdot \max_t(d_{t,r}) + \sum_h \hat{g}_{r,j}^{inv} + \hat{g}_{r,j}^{0} \qquad \forall\, r \tag{12}$$

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

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 distrort its full cost, fixeded costs are duly increased by 87600 €/MWa.

5. Flexibility options

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

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 (13). Equations (14) and (15) 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 (16) 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.

$$\mathrm{x}_{t,r,rr} = -\mathrm{x}_{t,r,rr} \qquad \forall t, r, rr \qquad (13)$$

$$\mathrm{x}_{t,r,rr} \le \hat{x}^{0}_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t, r, rr \qquad (14)$$

$$\mathrm{x}_{t,rr,r} \le \hat{x}^{0}_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t, r, rr \qquad (15)$$

$$\hat{x}^{inv}_{rr,r} = \hat{x}^{inv}_{r,rr} \qquad \forall t,r,rr \qquad (16)$$

The only electricity storage technology applied commercially today is pumped hydro storage. Thus storage is modeled after pumped hydro. Some storage technologies such as compressed air energy storage (CAES) have similar characteristics in terms of cycle efficiency, power-to-energy ratio, and specific costs and would have similar impact on model results. Other storage technologies such as batteries or gasification have very different characteristics and are not reflected in the model. The amount of energy stored at a certain hour $v_{t,r}$ is last hour's amount minus output $\mathrm{s}^{o}_{t,r}$ plus in-feed $\mathrm{s}^{i}_{t,r}$ (17). Both pumping and generation is limited by the turbines capacity $\hat{\mathrm{s}}_r$ (18), (19). The amount of stored energy is constrained by the volume of the reservoir $\hat{v}_r$, which are assumed to be designed such that they can be filled within eight hours (20). Hydrodynamic friction, seepage and evaporation cause the cycle efficiency to be below unity (2). The only costs related to storage except losses are capital costs in the case of new investments $\hat{\mathrm{s}}^{inv}_r$ (1).

$$v_{t,r} = v_{t-1,r} - \mathrm{s}^{o}_{t,r} + \mathrm{s}^{i}_{t,r} \qquad \forall t,r \qquad (17)$$

$$\mathrm{s}^{i}_{t,r} \leq \hat{\mathrm{s}}_r = \hat{\mathrm{s}}^{0}_r + \hat{\mathrm{s}}^{inv}_r \qquad \forall t,r \qquad (18)$$

$$\mathrm{s}^{o}_{t,r} \leq \hat{\mathrm{s}}_r = \hat{\mathrm{s}}^{0}_r + \hat{\mathrm{s}}^{inv}_r \qquad \forall t,r \qquad (19)$$

$$v_{t,r} \leq \hat{v}_r = (\hat{\mathrm{s}}^{0}_r + \hat{\mathrm{s}}^{inv}_r) \cdot 8 \qquad \forall t,r \qquad (20)$$

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.

6. Alternative Problem Formulation

In short, the cost minimization problem can be expressed as

$$\min C \qquad (21)$$

with respect to the investment variables $\hat{g}_{r,i}^{inv}$, $\hat{s}_{r}^{inv}$, $\hat{x}_{r,rr}^{inv}$, $\hat{x}_{r,rr}^{\mathrm{dec}}$, $\hat{k}_{r,h}^{inv}$, $\hat{k}_{r,h}^{dec}$, the dispatch variables $g_{t,r,i}$, $s_{t,r}^{i}$, $s_{t,r}^{o}$, 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 $p_{t,r}$, $p_{t,r,h}^{CHPgene}$, $p_{t,r,h}^{CHPcapa}$, p_{r}^{AS} and their aggregates $\overline{p}_{r}$, $f_{r,j}$.

7. 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 of 4 €/MWh on generation costs.

8. Model limitations

The model is highly stylized and has important limitations. Maybe the most significant caveat is the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Similarly, demand response in the form of demand shifting or an elastic demand function 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 absence of biomass; the aggregation of power plants into coarse groups; not accounting for market power or other market imperfections; ignoring all externalities of generation and transmission other externalities than carbon; ignoring uncertainty; not accounting for policy constraints (think of the nuclear phase-out in Germany); 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 1, reproduced from Hirth (2016), summarizes model features and limitations.

Table 1: Model features that are likely to significantly impact the wind market value

<table>
<tr><th>Features modeled</th><th>Features not modeled</th></tr>
<tr><td>

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

</td><td>
Impact likely to be <u>positive</u> for VRE (including these features would change value factor upwards)

Price-elastic electricity demand, e.g. from industry, electrical heating, or e-mobility
Include more countries

Impact likely to be <u>negative</u> for VRE (including these features would change value factor downwards)

Internal transmission constraints (SWE, GER) / 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

</td></tr>
</table>

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

9. Time Series Input Data

Two types of data are used in the model: time series data for every hour of the year, and scalar data. Each region’s electricity demand, heat demand, and wind and solar generation are described using hourly information. Historical data from the same year is used for these time series in order to preserve empirical 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 data were taken from various TSOs. Heat profiles are based on ambient temperature. Historical wind and solar generation data are only available from a few TSOs, and these series are not sufficiently representative for large-scale wind penetration if they are based on a small number of wind turbines: At higher penetration rate, a wider dispersed wind power fleet will cause the profile to be smoother. Thus VRE profiles were estimated from historical weather data using empirical estimated aggregate power curves. Data has been taken from the re-analysis model ERA-Interim.

10. Other Input Data

Fixed and variable generation costs are based on IEA & NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Schröder et al. (2013). They are listed in Table 2. Lignite costs include mining. Fuel prices are average 2010 European market prices, 9 €/MWh_t for hard coal and 18 €/MWh_t for natural gas, and the CO_2 price is 20 €/t. Availability is 0.8 for all technologies except French hydro, which is lower during the summer months. Alternatively, seasonal availability can be assumed to reflect historical patterns in scheduled unavailability during the low-demand season.

Summer 2010 ATC values from ENTSO-E were used to limit transmission constraints. CHP capacity and generation is from Eurelectric (2011b). An interest rate of 7% was used for all investments, including transmission and storage and VRE. Transmission investment costs are one million Euro per GW ATC capacity and km both for AC and DC lines. Screening curves and full cost curves of these technologies are displayed in Figure A3.

Table 2: Cost parameters of generation technologies.

			investment costs (€/KW)	quasi-fixed costs (€/KW*a)	variable costs (€/MWh_e)	fuel costs (€/MWht)	CO_2 intensity (t/MWht)	efficiency (1)
Dispatchable		Nuclear*	4000	40	2	3	-	0.33
	CHP possible	Lignite*	2200	30	1	3	0.45	0.38
		Lignite CCS*	3500	140	2	3	0.05	0.35
		Hard Coal*	1500	25	1	12	0.32	0.39
		CCGT	1000	12	2	25	0.27	0.48
		OCGT**	600	7	2	50	0.27	0.30
		Load shedding	-	-	-	***1000	-	1
VRE		Wind	1300	25	-	-	-	1
		Solar	2000	15	-	-	-	1
		Pumped hydro**	1500	15	-	-	-	0.70

Nuclear plants are assumed to have a life-time of 50 years, all other plants of 25 years. OCGT fuel costs are higher due to structuring costs. Lignite costs include mining.
* Base-load plants run even if the electricity price is below their variable costs (run-through premium).
**Flexible technologies are assumed to earn 30% of their investment cost from other markets (e.g. regulating power).
***This can be interpreted as the value of lost load (VOLL).

This formulation of VRE cost implies that there are no supply curves or resource constraints: There is unlimited supply of wind and solar at the given cost level at the same amount of FLH. In other words, the marginal cost curves of wind and solar are flat. However, since the high-resolution modeling ensures that the marginal benefit of VRE is falling with penetration, there will be always a stable optimum, and no "flipping" behavior between technologies.

11. Short-term vs. long term

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 the 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, if markets are perfect, 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. This paper applies a mid-term perspective and in addition provides some long-term results.

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 is 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.

12. Notation

Subscripts (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	GER,FRA,POL,NLD,BEL, SWE, NOR
Power generating technologies	$i \in I$	tec_mod	nucl,lCCS,lign,coal,CCGT,OCGT,shed,wind,solar,PHS,hydr
VRE technologies	$j \in J$	tec_res(tec_mod)	wind,solar
Thermal technologies	$k \in K$	tec_thm(tec_mod)	nucl,lCCS,lign,coal,CCGT,OCGT,shed
CHP technologies	$h \in H$	tec_chp(tec_mod)	lign,coal,CCGT,OCGT,shed

Capacity: overview					
	total capacity (variable)	inital/ existing capacity (parameter)	added capacity (variable)	decommissioned capacity (variable)	corresponding dispatch variable (hourly)
generation	$\hat{g}_{r,i}$	$\hat{g}^{0}_{r,i}$	$\hat{g}^{inv}_{r,i}$	$\hat{g}^{dec}_{r,i}$	$g_{t,r,i}$
export / import	$\hat{x}_{r,rr}$	$\hat{x}^{0}_{r,rr}$	$\hat{x}^{inv}_{r,rr}$	$\hat{x}^{\mathrm{dec}}_{r,rr}$	$\mathrm{x}_{t,r,rr}$
storage volume	$\hat{v}_{r}$	$\hat{v}^{0}_{r}$	$\hat{v}^{inv}_{r}$	$\hat{v}^{dec,}_{r}$	$v_{t,r}$
storage in- / output	$\hat{\mathrm{s}}_{r}$	$\hat{\mathrm{s}}^{0}_{r}$	$\hat{\mathrm{s}}^{inv}_{r}$	$\hat{\mathrm{s}}^{dec}_{r}$	$\mathrm{s}^{o}_{t,r}, \mathrm{s}^{i}_{t,r}$
CHP capacity	$\hat{k}_{r,h}$	$\hat{k}^{0}_{r,h}$	$\hat{k}^{inv}_{r,h}$	$\hat{k}^{dec}_{r,h}$	-

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	eff("PHS")	1
VRE generation profile	$\varphi_{t,r,j}$	profile(t,j,r)	1
CHP min generation profile	$\varphi_{t,r,chp}$	profile(t,"CHP",r)	1
Technical availability	$\alpha_{t,r,k}$	avail(t,alltec,r)	1
Minimal thermal generation	σ_{r}		GW
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_i^{qfix}	cost_qfix(alltec)	$\frac{M€}{GW \cdot a} = \frac{€}{kW \cdot a}$
Interconnector capital costs (specific, annualized)	c^{ATC}	cost_NTC	$\frac{M€}{GW_{ATC} \cdot km \cdot a}$
Cost (variables)	**Documentation**	**Gams**	**Unit**
Total System costs	C	-	M€
Fixed generation costs	$C_{r,i}^{fix}$	-	M€
Variable generation costs	$C_{t,r,i}^{var}$	-	M€
Capital costs of storage	C_r^{sto}	-	M€
Capital costs of transmission	$C_{r,rr}^{ATC}$	-	M€
Parameters (initial capacities)	**Documentation**	**Gams**	**Unit**
Minimal CHP capacity	γ_r	capaCHP0tot(r)	GW
Initial generation capacity	$\hat{g}_{r,i}^0$	capa0(alltec,r)	GW
Initial Interconnector Capacity	$\hat{x}_{r,rr}^0$	ntc(r,rr)	GW_{ATC}
Initial PHS volume	$\hat{v}_r$	capa0(alltec,r)	GWh
Initial PHS turbine capacity	$\hat{s}_r$	-	GW
Capacity of CHP capacity	$\hat{k}_{r,h}$	capaCHP0(tec_chp,r)	GW
Variables (dispatch - hourly)	**Documentation**	**Gams**	**Unit**
Generation	$g_{t,r,i}$	GENE(t,alltec,r)	GW
Exports (net)	$x_{t,r,rr}$	FLOW(t,r,rr)	GW
Storage volume	$v_{t,r}^{vol}$	STO_V(t,r)	GWh
Storage output	$s_{t,r}^o$	GENE(t,"PHS",r)	GW
Storage in-feed	$s_{t,r}^i$	STO_I(t,r)	GW
Variables (investment, divestment - yearly)	**Documentation**	**Gams**	**Unit**
CHP capacity: invested ; decommissioned	$k_{r,h}^{inv}$; $k_{r,h}^{dec}$	inveCHP(tec_chp,r)	GW
Pumped hydro storage volume capacity: invested ; decommissioned	$\hat{v}_r^{inv}$; $\hat{v}_r^{dec}$	STO_CAP(r)	GWh
Pumped hydro storage turbine capacity: invested ; decommissioned	$\hat{s}_r^{inv}$, $\hat{s}_r^{dec}$	-	GW
Additional Interconnector Capacity	$\hat{x}_{r,rr}^{inv}$	NTCinv(r,rr)	GW
Volume of reservoirs	$\hat{v}_r$	RESERVOIR_V(t,r)	GWh
Turbine capacity	$\hat{s}_r$	-	GW

Dispactchable capacity: invested ; decommissioned	$\hat{g}_{r,k}^{inv}$, $\hat{g}_{r,k}^{dec}$	INVE(tec_mod,r) DECO(tec_mod,r)	GW
Shadow prices	**Documentation**	**Gams**	**Unit**
Hourly electricity price	$p_{t,r}$	o_p(t,r)	€/MWh
Shadow price of CHP generation constraint	$p_{t,r,h}^{CHPgene}$	o_revH(tec_chp,r)	€/MWh
Shadow price of CHP capacity constraint	$p_{t,r,h}^{CHPcapa}$	o_revH(tec_chp,r)	€/(kW*a)
Shadow price of ancillary services	$p_{t,r}^{AS}$	o_ASp(r)	$€/kW_{online} \cdot a$
Base price	$\overline{p}_{r}$	o_bp(r)	€/MWh
Value factor	$f_{r,j}$	o_vf(alltec,r)	(1)

13. Applications

EMMA has been applied for a range of academic studies and consulting projects.

Peer-reviewed publications

Hirth, Lion (2018): "What caused the drop of European electricity prices? A factor decomposition analysis", *The Energy Journal* 39 (1).

Hirth, Lion & Jan Steckel (2016): "The role of capital costs for decarbonizing the electricity sector", *Environmental Research Letters* 11, DOI: 10.1088/1748-9326/11/11/114010.

Hirth, Lion (2016): "The benefits of flexibility: The value of wind energy with hydropower", *Applied Energy* 181, 2010-223, DOI: 10.1016/j.apenergy.2016.07.039.

Hirth, Lion & Simon Müller (2016): "System-friendly Wind Power", *Energy Economics* 56, 51-63, DOI:10.1016/j.eneco.2016.02.016.

Hirth, Lion (2015): "The Optimal Share of Variable Renewables: How the Variability of Wind and Solar Power affects their Welfare-optimal Deployment", *The Energy Journal* 36(1), 127-162, DOI:10.5547/01956574.36.1.6.

Hirth, Lion (2015): "The Market Value of Solar Power: Is Photovoltaics Cost-Competitive?", *IET Renewable Power Generation* 9(1), 37-45, DOI:10.1049/iet-rpg.2014.0101.

Hirth, Lion & Falko Ueckerdt (2013): "Redistribution Effects of Energy and Climate Policy: The Electricity Market", *Energy Policy* 62, 934-947, DOI:10.1016/j.enpol.2013.07.055.

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Hirth (2016a), Hirth (2016b), Hirth & Steckel (2016), Hirth & Müller (2016), Hirth (2015a), Hirth (2015b), Hirth & Ueckerdt (2013), Hirth (2013).

Consulting projects

System-friendly wind and solar power (IEA). Model-based study for the International Energy Agency, Paris. Neon assessed the market and system benefits of low-wind speed wind turbines and east- and west-oriented PV based on its power market model EMMA. 2014-16. The study is published in *Energy Economics*. More

Wind market value in the Nordic region (Energiforsk). Model-based assessment of the market value of wind power in the hydro-dominated power system of the Nordic region. Neon design the study, developed the model, and wrote the report. 2016.

Reasons for the Nordic price drop (Swedish Energy). Swedish wholesale power prices declined by two thirds 2010-15. Neon conducted a model-based assessment of the reasons for this price drop. 2016.

Total system costs (IEA / NEA). Model-based assessment for the IEA and the Nuclear Energy Agency for the report "Projected costs of electricity".