The European electricity market model EMMA

The European Electricity Market Model EMMA is a stylized numerical dispatch and investment model of the interconnected Northwestern European power system that has been applied in Hirth (2013), Hirth & Ueckerdt (2013), and Hirth (2014) to address a range of research questions. In economic terms, it is a partial equilibrium model of the wholesale electricity market. It determines optimal or equilibrium yearly generation, transmission and storage capacity, hourly generation and trade, and hourly market-clearing prices for each market area. Model formulations are parsimonious while representing wind and solar power variability, power system inflexibilities, and flexibility options with appropriate detail. The model is freely available to the public under the Creative Commons BY-SA 3.0 license. This page discusses crucial features verbally. More resources can be found here:

1. Overview

EMMA minimizes total costs with respect to investment, production and trade decisions under a large set of technical constraints. Markets are assumed to be perfect and complete, such that the social planner solution is identical to the market equilibrium and optimal shares of wind and solar power are identical to competitive shares. The model is linear, deterministic, and solved in hourly time steps for one year.

For a given electricity demand, EMMA minimizes total system cost, the sum of capital costs, fuel and CO2 costs, and other fixed and variable costs, of generation, transmission, and storage assets. Capacities and generation are optimized jointly. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and 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 is modeled as eleven discrete technologies with continuous capacity: two VRE with zero marginal costs – wind and solar –, six thermal technologies with economic dispatch – nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS) –, a generic "load shedding" technology, and pumped hydro storage. Hourly VRE generation is limited by generation profiles, but can be curtailed at zero cost. Dispatchable plants produce whenever the price is above their variable costs. Storage is optimized endogenously under turbine, pumping, and inventory constraints. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments including VRE have to recover their annualized capital costs from short-term profits.

The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices on an energy-only market with scarcity pricing. This guarantees that in the long-term equilibrium the zero-profit condition holds. As numerical constraints prevent modeling more than one year, capital costs are included as annualized costs.

Demand is exogenous and assumed to be perfectly price inelastic at all but very high prices, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales. 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.

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. Ancillary service provision is modeled as a must-run constraint for dispatchable generators that is a function of peak load and VRE capacity.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs). 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.

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: assigned base load plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.

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

Being a stylized power market model, EMMA has significant limitations. An important limitation is the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Hence, results are only valid for predominantly thermal power systems. Demand is assumed to be perfectly price inelastic up to high power prices. More elastic demand would help to integrate VRE generation. However, it is an empirical fact that demand is currently very price-inelastic in Europe and possible future demand elasticities are hard to estimate. Technological change is not modeled, such that generation technologies do not adapt to VRE variability. Not accounting for these possible sources of flexibility potentially leads to a downward-bias of optimal VRE shares. Hence, results can be interpreted as conservative estimates.

EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. In a back-testing exercise, model output was compared to historical market data from 2008-10. Crucial features of the power market can be replicated fairly well, like price level, price spreads, interconnector flows, peak / off-peak spreads, the capacity and generation mix.

2. Total System Costs

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 $C_{r,rr}^{trans}$ over all time steps t, regions r, and generation technologies i:

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

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-fixeded costs such as fixed 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^{var} that include fuel, CO_2, and variable O&M costs. Investment in pumped hydro storage capacity $\hat{s}_r^{io,inv}$ 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 NTC investment costs per MW and km c^{NTC}.

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.

There are eleven technologies, five regions, and 8760 times steps modeled. Note that (1) does not contain a formulation for distribution grids, which contribute a significant share of household electricity cost.

3. Supply and Demand

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 $g_{t,r,i}$ minus the sum of net exports $x_{t,r,rr}$ plus storage output $s_{t,r}^{o}$ minus storage in-feed $s_{t,r}^{i}$. 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.

$$\delta_{t,r} \le \sum_i g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s^o_{t,r} - s^i_{t,r} \qquad \forall t,r \tag{2}$$

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

$$\bar{p}_r \equiv \sum_t p_{t,r} \Big/ T \qquad \forall r$$

Generation is constraint by available installed capacity. Equation (3) states the capacity constraint for the vRES technologies $j \in i$, wind and solar power. Equation (4) is the constraint for dispatchable generators $m \in i$, 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 maintenance. Dispatchable capacity can be decommissioned endogenously via $\hat{g}^{dec}_{r,k}$ to save on quasi-fixeded costs, while vRES capacity cannot. Both generation and capacities are continuous variables. The value factors $v_{r,j}$ are defined as the average revenue of wind and solar relative to the base price.

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

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

$$v_{r,j} \equiv \sum_t \varphi_{t,r,j} p_{t,r} \Big/ \sum_t \varphi_{t,r,j} \Big/ \bar{p}_r \qquad \forall r, j \in i$$

Minimizing (1) under the 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 2012).

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 $h \in m$, which are the five coal- or gas-fired technologies, does not drop below minimum generation $g_{t,r,h}^{min}$. Minimum generation is a function of the amount of CHP capacity of each technology $k_{r,h}$ 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 $k_{r,h}^{inv}$ as well as decommissioning of CHP $k_{r,h}^{dec}$ 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 $p_r^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heating energy and capacity, respectively.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = k_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} \qquad \forall t,r,h \in m \qquad (5)$$

$$k_{r,h} \leq \hat{g}_{r,h} \qquad \forall r,h \qquad (6)$$

$$\sum_h k_{r,h} \geq \gamma_r = \sum_h k_{r,h}^0 \qquad \forall r \qquad (7)$$

$$k_{r,h} = k_{r,h}^0 + k_{r,h}^{inv} - k_{r,h}^{dec} \qquad \forall r,h \qquad (8)$$

$$k_{r,h}^{inv} \leq \hat{g}_{r,h}^{inv} \qquad \forall r,h \qquad (9)$$

$$k_{r,h}^{dec} \leq \hat{g}_{r,h}^{dec} \qquad \forall r,h \qquad (10)$$

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

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

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.

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.

$$\sum_k g_{t,r,k} - \sum_h \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} + \eta \cdot s_{t,r}^o + s_{t,r}^i \geq \sigma_r \qquad \forall t,r \tag{11}$$

$$\sigma_r = 0.1 \cdot \max_t \left(d_{t,r}\right) + 0.05 \cdot \sum_j \hat{g}_{r,j}^{inv} + \hat{g}_{r,j}^0 \qquad \forall r \tag{12}$$

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

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 (NTCs). Ignoring transmission losses, the net export $x_{t,r,rr}$ 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 $\hat{x}_{r,rr}^0$ and new interconnector investments $\hat{x}_{r,rr}^{inv}$. 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 $\delta_{r,rr}$ is measured between the geographical centers of regions.

$$x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t,r,rr \tag{13}$$

$$x_{t,r,rr} \le \hat{x}^{0}_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t,r,rr \tag{14}$$

$$x_{t,rr,r} \le \hat{x}^{0}_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t,r,rr \tag{15}$$

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

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 $s^{vol}_{t,r}$ is last hour's amount minus output $s^{o}_{t,r}$ plus in-feed $s^{i}_{t,r}$ (17). Both pumping and generation is limited by the turbines capacity $\hat{s}_r$ (18), (19). The amount of stored energy is constrained by the volume of the reservoirs $\hat{s}^{vol}_r$, 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 $\hat{s}^{inv}_r$ (1).

$$s^{vol}_{t,r} = s^{vol}_{t-1,r} - s^{o}_{t,r} + s^{i}_{t,r} \qquad \forall t,r \tag{17}$$

$$s^{i}_{t,r} \le \hat{s}_r = \hat{s}^{0}_r + \hat{s}^{inv}_r \qquad \forall t,r \tag{18}$$

$$s^{o}_{t,r} \le \hat{s}_r = \hat{s}^{0}_r + \hat{s}^{inv}_r \qquad \forall t,r \tag{19}$$

$$s^{vol}_{t,r} \le \hat{s}^{vol}_r = \left(\hat{s}^{0}_r + \hat{s}^{inv}_r\right)\cdot 8 \qquad \forall t,r \tag{20}$$

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 one million equations and four million non-zeros. 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

$$\min \quad C \tag{21}$$

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

7. Model limitations / shortcomings

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 vRES fluctuations. Similarly, demand response in the form of demand shifting or an elastic demand function would help to integrate vRES generation. Ignoring these flexibility resources leads to a downward-bias of vRES market values.

On the other hand, not accounting for internal grid constraints and vRES forecast errors, the model does not take into account location and balancing costs, overestimating the market value of vRES.

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 vRES resource constraints; ignoring grid constraints at the transmission and distribution level; any effects related to lumpiness or economies of scale of investments.

8. 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 vRES 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 vRES profiles were estimated from historical weather data using empirical estimated aggregate power curves. Wind load factors in all countries are scaled to 2000 full load hours to understand the impact of different profile structures. Time series data from 2010 were used for this paper.

The correlation of vRES profiles with other parameters crucially determines their marginal benefit and thus their optimal market share. Table 5 reports correlation coefficients on an hourly basis for a selected number of parameters. While solar profiles are highly correlated across countries, wind is only moderately correlated. The seasonal pattern of wind is correlated with demand (higher in winter, lower in summer), while the diurnal pattern of solar is correlated with demand (high around noon). The stronger seasonal fluctuation of French demand due to electric space heating imply a higher correlation of wind with demand in France than in Germany (vice versa for solar).

Table 1: Coefficients of correlation between hourly wind profiles, solar profiles, and demand for Germany and France.

	wGER	wFRA	sGER	sFRA	dGER	dFRA
wGER	1					
wFRA	.33	1				
sGER	-.12	-.11	1			
sFRA	-.08	-.12	.95	1		
dGER	.16	.11	.18	.21	1	
dFRA	.17	.19	-.14	-.13	.70	1

9. Other Input Data

Fixed and variable generation costs are based on IEA & NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Nicolosi (2012) and listed in Table 2. Lignite costs include mining. Fuel prices are average 2011 market prices free power plant including structuring costs. Availability is 0.8 for all technologies except French hydro, which is lower during the summer months. Summer 2010 NTC 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 vRES. Transmission investment costs are one million Euro per GW NTC 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
vRES		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 vRES 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 vRES is falling with penetration, there will be always a stable optimum, and no "flipping" behavior between technologies.

10. Exogenous vs. Endogenous Capital Stock

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.

An alternative to estimate a static equilibrium at one point in time is to model an optimal path dynamically, that is in a sequence of time steps. For example, one can start with today's capacity and model the transition path to the long-term equilibrium. In practice, dynamic model frameworks are often more complex: typically such approaches start today and optimize the electricity system for the future, assuming perfect foresight. Often input parameters are changed over time, such that the system never approaches any static equilibrium, but follows an optimal path. A downside of this approach is that the complexity of the optimization problem increases dramatically. Thus often the temporal resolution of the dispatch problem is reduced to cope with numerical problems. Another downside, also related to complexity, is that attributing effects to causes and identifying chains of causality becomes often impossible due to the multitude of changing parameters and the dynamic nature of the problem. While static equilibria are mainly used in the academic context to analyze the effect of an individual or a small number of policies or shocks, dynamic optimal-path approaches are more frequently applied in forecasting, system planning, or policy advice.

Table 3: Analytical frameworks

	Short term / Static	**Medium term / Transition**	**Long term / Green Field**
Existing Capacity	included	included or partially included (subject to technical life-time)	not included
(Dis)investment	none or exogenously given	modelled	modelled
Model	dispatch	dispatch & investment	dispatch & investment
Value of vRES (avoided costs in the residual system)	variable costs (fuel, variable O&M, CO_2)	• variable costs • quasi-fixeded costs (if incumbent plants are decommissioned • fixeded costs (if new plants are avoided)	variable and fixeded costs
Long-term profits at respective equilibrium	positive or negative	• positive or negative for incumbent capacity • zero for new capacity	zero
References	Sensfuß (2007); many studies that assess technical feasibility of grid integration	Mills & Wiser (2012), Neuhoff et al. (2008), Nicolosi (2012), Färber et al. (2012), Short et al. (2011), Haller et al. (2011), Rosen et al. (2007), Nagl et al. (2012); most integrated assessment models	Lamont (2008), Bushnell (2010), Green & Vasilakos (2011)

Quasi-fixeded costs are fixeded O&M costs. Fixeded costs are quasi-fixeded costs plus investment (capital) costs.

The aim of this paper is to estimate the welfare-optimal amount of wind power under different parameters. The following approach was applied, both in a mid-term and a long-term framework: first, the optimal share was estimated under best-guess ("benchmark") assumptions of energy system parameters for several levels of vRES costs. Then, these parameters are systematically varied to understand their impact on optimal vRES deployment, again at different cost levels.

11.Modeling 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.

In reporting, balancing costs are *not* reported as part of the LEC; LEC only includes capital and O&M costs.