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Simulation of the European electricity market and CCS development with the HECTOR model

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Abstract

In this paper we introduce HECTOR, a new and advanced long-term electricity market model that simulates market behavior bottom-up through opportunistic, variable cost-based bidding of individual power plants into auction-based national markets with international interconnection capacities. Unlike most other approaches, we implement the objective function on an hourly level. This allows for a reduction of the solution space, and enables a higher modeling resolution, including opportunistic bidding behavior of power plants based on expected supply scarcity, and ex-post investment decisions based on NPV considerations. The model simulates the electricity markets of 19 European countries, with over 400 groups of power plants, and is able to closely approximate historic electricity prices. The average base load price computed by the model for 2006-2008 and across the largest regions in Europe is 54.5 €/MWh, compared to 54.8 €/MWh in reality, using 2005 as training period. In a projection until 2040, we find that conventional fossil fuel-fired power plants are replaced both by renewable energy technologies and large quantities of CCS, the latter of which almost fully utilize available CO_2 storage capacities in some of the regions studied.

Key words: Electricity market, simulation, model, forecast, CCS

JEL classification: C63, O30, Q47

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1. Introduction and model categorization

In this paper we introduce HECTOR, the Hourly Electricity, CCS and Transmission Optimizer, and report on a model-based projection of the development of the European electricity market and the diffusion of carbon capture and storage (CCS) until 2040.

Following the classification of electricity models by Ventosa and associates into optimization, equilibrium, and simulation models (VENTOSA et al., 2005), HECTOR may be categorized as a simulation model. It simulates generation, auctioning, dispatch and cross-border flows of electricity as well as capacity changes arising from plant investments and retirements. The model is a further development of a model originally introduced by GROBBEL (1999). Simulation covers the electricity markets in Europe, with a particular focus on the supply side[1]. Economic variables that are typically found in macroeconomic electricity models[2], such as GDP or demographic development, are treated as exogenous. The model is based on the mathematical representation of a problem with an objective function and constraints. A distinctive feature of this long-term model is that objective functions are created and solved separately for each hour instead of having one for the entire decision or simulation period, e.g. five or forty years. Specifically, separate solving breaks up the solution space into smaller pieces, allowing the model to represent reality in a greater level of detail than most other long-term models found in the literature, while at the same time maintaining computability.

This paper is organized as follows. The model and the approach adopted are described in section 2. The input data are reported in section 3. The detail of the model is needed for representing the electricity markets, and CSS as its special focus, as accurately as possible. In section 4, we test how well the model is able to simulate reality by comparing the model outcome against the historic values for the years 2005-2008. Later in that section, we provide an outlook on future development starting in 2009; specifically, we show the development of energy prices, CCS deployment, as well as power plant capacity evolution and supply curves

[1] Similar to most electricity models, e.g., TIMES-D (ETSAP/IER Stuttgart), DIOGENES (ZEW Zentrum für Europäische Wirtschaftsforschung), EMET-Capture, PERSEUS-CERT (IIP Karlsruhe), DIME or GEMS (EWI Köln), WEsER (ForWind Zentrum für Windenergieforschung), IKARUS-MARKAL (Forschungszentrum Jülich) or WMI (Wuppertal Institut). See VENTOSA et al. (2005) for a more comprehensive list of available electricity models and their categorization.

[2] E.g., MESSAGE-MACRO (MESSNER/SCHRATTENHOLZER, 2000) or MERGE (MANNE et al., 1995).

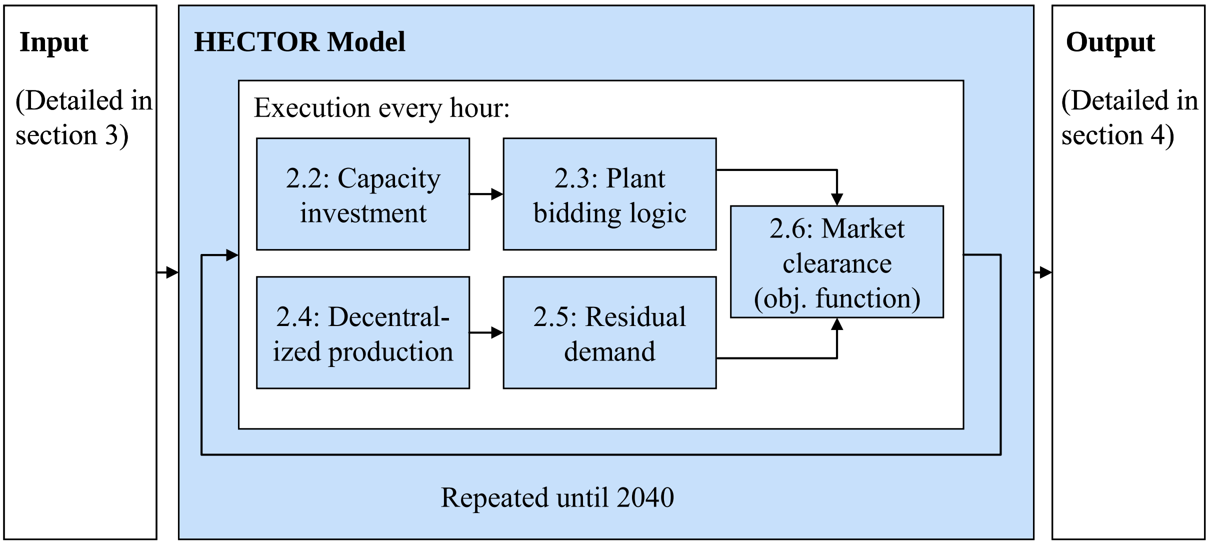
until 2040 for 19 European countries[3]. Section 5 summarizes the key findings and offers an overall conclusion.

2. Model description

2.1. Overview and overarching concept

HECTOR comprises five different modules, as illustrated in Figure 1. Each module is executed once in every time step, and builds on information from the previous time step. For a typical simulation run from 2005 to 2040, HECTOR therefore executes each module about 300,000 times (35 years * 365 days * 24 hours).

Figure 1: Conceptual overview of all modules in HECTOR.



NOTE: Numbers (2.x) refer to the section numbers further below in which the respective modules are described in detail.

In each time step (hour), the model evaluates the profitability to build new power plants based on an NPV estimate and, if positive, builds a new plant (section 2.2). In a second step, a price and volume bid that maximizes individual return is calculated for each flexible plant (section 2.3). In parallel, the model calculates decentralized or intermittent production (wind power,

[3] EU-15 member countries without Luxembourg and Ireland, as well as Norway, Switzerland, the Czech Republic, Hungary, Poland and the Slovak Republic.

solar power, run-of-river hydro power etc.), either endogenously based on wind speeds or through exogenous input for the other sources (section 2.4). It then subtracts this production from the overall demand (section 2.5) in order to obtain the residual demand. Finally, the model combines the given demand with the supply bids for each region, by solving for the lowest overall cost and by considering transport grid boundaries while satisfying demand (section 2.6). In essence, this resembles the hourly auction observed at electricity exchanges such as EEX in Leipzig or PowerNext in Paris.

The most common approach for long-term electricity models is to solve a period far beyond the hourly time-step presented (VENTOSA et al., 2005)[4]. The objective function either minimizes overall system costs or maximizes social welfare through plant capacity investment costs subject to a set of constraints. These constraints are, e.g., the satisfaction of electricity demand, targets on CO_2 emissions and renewables, or specific reserve capacities. This approach leads to a cost-minimizing portfolio of generation technologies. The downside is a large solution space, because different demand profiles[5], plant dispatch decisions, cross-border flows, etc. must be satisfied simultaneously throughout the objective function's period. A large solution space and, therefore, computational complexity leads to limitations in terms of detail and solving time, since processing power is not unlimited.

Narrowing the objective function's period down from several years to a time-step of one hour, however, leads to a lack of available information. The main information needs are for market prices and for installed capacity[6], both for the past (which is trivial) and the future. The approach also needs different decision variables, since the traditional variable 'capacity investment' does not influence the objective of minimal system costs any more if the objective function's period is reduced to one hour.

In order to achieve the desired hourly time-step, we deploy three design elements:

- *Detailed calculation of the electricity market price.* As the endogenous electricity price is the key information passed on between time steps, its accurate estimation is vital. Capacity investment/divestment or mothballing decisions are based on the expected NPV, and

[4] This can be the entire modeling period or a decision period, e.g., five years, to resemble power plant construction time.

[5] E.g., the DIME model (EWI, 2008) generates a standard weekday, Saturday, and Sunday for all four seasons of the year. For one year, the model then solves for 3*4 = 12 days and multiplies them by their frequency.

[6] Other factors, such as electricity demand or cross-border constraints, are external input and not calculated endogenously.

the revenues are a direct consequence of electricity prices. To achieve this accuracy, we make use of detailed data, splitting the European generation capacity into more than 400 individual power plant groups, each with its own capacity (with plant age tracked separately), thermal efficiency and other technical constraints, such as start-up/shut-down costs and delays, least sustainable load levels[7], etc. Then, we emulate the price/volume bidding of all plants independently, considering opportunistic bidding behavior based on expected supply scarcity and opportunity costs. The power plants, therefore, can be considered as agents who act independently of each other. Section 2.3 describes this approach in greater detail, while section 4.1 provides a comparison of model results with historic annual prices and price duration curves.

- *Plant dispatch as the decision variable.* While we still use minimal system costs (defined as the sum of electricity costs to satisfy demand in all regions) as the objective function, the decision variable is whether a plant is dispatched in the simulated hour (see section 2.6 for details). Plant investments or plant closings as typical decision variables of long-term electricity models are calculated *ex-post*, based on historic and expected market prices and fuel levels, leading to an expected NPV of plant investments. Positive NPVs then lead to plant investments. Section 2.2 below explains this logic in more detail.
- *Simulation of a future market.* Besides simulating the current market, the model also deploys the same bidding behavior and market allocation technique for a future market five years ahead in time, in order to calculate future price estimates needed primarily for plant investment/shut-down decisions. In this simulation, we consider future fuel and CO_2 prices and demand profiles, but only some power plants currently under construction in order to model imperfect information of investors. This is explained in some more detail in section 2.2.

With these design choices, the model evaluates about 1,300 equations per time step. It is run with regular desktop hardware, and can simulate every hour in every week until 2040 or, alternatively, only every hour in the 4th week, cutting runtime to one fourth. In this mode, the simulation takes about one and a half hours for a full simulation from 2005 until 2040[8].

[7] Minimum load level at which the plant can still operate without having to fully shut down.

[8] On Intel i7 Quad core hardware, 4 x 3.7 GHz CPUs, 6 GB RAM, using the Vensim Simulation Software and Microsoft Windows 7.

2.2. Capacity investments

HECTOR combines similar power plants into homogeneous groups with the same technology, operating parameters (e.g. efficiency), and region. This leads to typically 3-5 groups for each technology (nuclear, hard coal, etc.) per region. Whereas a group has identical thermal efficiency, fixed and variable costs, startup and shutdown times/costs, etc., it maintains the age of its members on an individual plant level. This allows the model to construct, retire, or mothball single plants within a group without increasing the computational complexity. The model divides capacity into four groups:

- *Static capacity* (hydro and nuclear): Excluded from investment and retirement decisions, capacity development is treated as exogenous. For hydro plants, the model assumes that all feasible locations for hydro plants in Europe are already utilized, and that reinvestments in plants soon to be retired will prevent such retirements (lifetime extension). For nuclear plants, we assume that deployment is driven mainly by political decisions and not so much by economic considerations. We therefore adopt the individual national announcements on investments and retirements active at the time of writing this article[9].
- *Decentralized production* (wind turbines, biomass, geothermal, solar, tidal, fuel cells): This is taken as an external input, as its capacity evolution is driven mainly by policy targets on renewables (see section 2.4.).
- *Thermal capacity* (oil, natural gas, hard coal, lignite): The model simulates investments and shut-downs based on economic considerations. It relies on a net present value (NPV) calculation based on expected, and therefore uncertain, future revenues.
- *Thermal (hard-coal[10]) capacity with CCS*: Here, the same NPV logic applies as for regular thermal capacity, but now the specific characteristics of CCS are taken into ac-

[9] The discussion about lifetime extensions for German nuclear plants after the federal election 2009 has, as of November 2009, not yet resulted in policy amendments, so the model deploys the existing phase-out policy (retirement of all 17 currently existing German nuclear power plants by 2021).

[10] The model uses CCS only for hard coal-fired power plants, which is the most promising CCS application compared to CCS for natural gas and, due to its regionally limited applicability, CCS for lignite. As it is still not known which of the CCS technologies – post-combustion, pre-combustion, or Oxyfuel – will become the dominant CCS technology, the modeled plant does not refer to a specific technology but rather to a blend of all three (same approach as adopted in MCKINSEY, 2008).

count as well. This includes available CO_2 storage capacity throughout the lifetime of the plant in the relevant country, and transport and storage costs.

As mentioned in the previous section, the model does not simultaneously optimize over several years and, as a result, does not know the future revenues needed for an NPV calculation. It therefore tries to approximate investor expectations by also simulating a future electricity market five years in the future. In this future market, all modules shown in Figure 1, with the exception of the capacity investment module, are executed. This is just like in the present market, but with perfect-foresight future fuel prices, demand levels, and power plants currently under construction. To simulate imperfect information, we introduce a delay of one year before the construction of new power plants is reflected in the future price. Additionally, any potential capacity investment decisions that might happen after the current simulation step are not considered in the future price. The effect of imperfect information is overinvestment and cyclicality, which is what we also observe in real market situations. In summary, at any point in time t the model generates a present market price, P_t, and a future market price, P_{t+5yrs}. The model then calculates any market prices beyond five years ahead based on the development of the weighted fuel price[11].

Based on knowledge about future market prices as well as variable, fixed, and investment costs, WACC, and local tax rates, the model calculates an NPV for all available technologies (oil, simple and combined cycle natural gas, regular and CCS-equipped hard coal, lignite) for every region. Whenever a technology continuously exhibits a positive NPV over a certain period of time and there are no constraints (e.g., insufficient CO_2 storage space for CCS plants), the model builds a new power plant. After one year, this plant participates in the simulation of the future market, and after its construction is completed it also participates in the present market.

The model applies a similar logic to mothballing and retirements: If a plant does not recover its fixed costs over a certain amount of time and if the expectation is also negative, it is temporarily shut down (mothballed). If the market situation becomes more favorable again and has a positive outlook, the model reactivates the plant. Otherwise, the capacity is finally

[11] Every fuel is weighted based on how frequently it is price-setting. For example, if gas plants are price-setting in 40% of the time (i.e., it is the technology with the highest marginal cost below the market price) and coal plants for the remaining 60%, gas price development is weighted with 40% and coal price development with 60%.

decommissioned. Additionally, the model decommissions plants that have reached their retirement age (except for exogenously determined capacity, see above).

2.3. Plant bidding

HECTOR dispatches plants whenever the price bid is below the market price for the hour concerned[12]. The market price itself is again a direct result of all bids provided. Just as in reality, every power plant can, therefore, influence the market price and, through opportunistic behavior, improve its position. Bidding is simple for non-thermal plants that either always run (e.g., hydro run-of-river) or always produce when feasible (e.g., wind, solar). These plants are directly deducted from demand as decentralized capacity. This is not the case for thermal and (pump-)storage hydro plants that have both the technical and economic flexibility to be shut down or run at minimum load. To approximate observed prices during base and peak load at existing energy exchanges, HECTOR simulates this behavior by considering several aspects in the price ($price\_bid_{p,r,t}$) and volume bid ($vol\_bid_{p,r,t}$) for each of these plant groups p in region r at time t as follows:

$$price\_bid_{p,r,t} = (var\_cost_{p,r,t} + opportunity\_cost_{p,r,t}) \cdot density\_increase_{r,t} \qquad \forall\, p,r \qquad (1)$$

$$vol\_bid_{p,r,t} = \left\{ \begin{array}{ll} maximum\_load_{p,r} & \text{if } price\_bid_{p,r,t} \geq var\_cost_{p,r,t} \\ maximum\_load_{p,r} & \text{if } p \text{ is } nuclear\ power\ plant \\ least\_sustainable\_load_{p,r} & \text{otherwise} \end{array} \right\} \qquad \forall\, p,r \qquad (2)$$

with the following components:

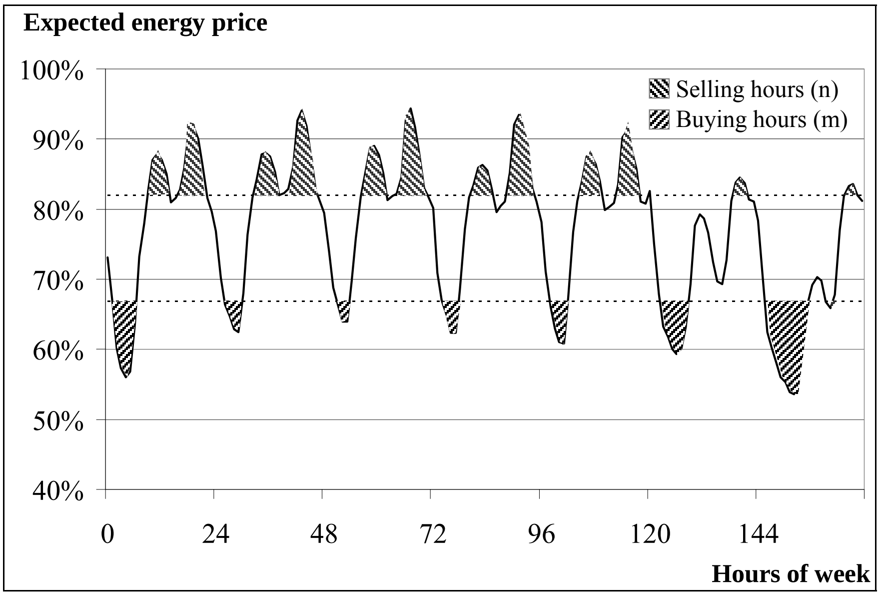
- $var\_cost_{p,r,t}$: Fuel costs, fuel transport costs, variable O&M costs, CO_2 EUA licensing costs and, for CCS plants, also CO_2 transport and storage costs occurring at full load for power plant group p in region r at time-step t. Fuel and CO_2 costs are updated monthly, all other components annually. For hydro plants, this cost component is zero.
- $opportunity\_cost_{p,r,t}$: Opportunity costs consider costs of avoided or anticipated shutdowns or start-ups and water inflow for (pump-)storage hydro plants. The model explicitly considers start-up and shut-down durations and costs. The model has five cases for opportunity costs:

[12] The model assumes a pool market in every region without bilateral contracts, which is not always the case. In the long run, arbitrage opportunities ensure that prices in bilateral (over-the-counter) agreements will not deviate significantly from the pool market prices.

1. Prohibitively expensive costs of shutdowns for nuclear plants always lead to a zero price bid (*opportunity_cost* = - *var_cost*);
2. A running plant expecting low prices for a limited amount of time bids at low or zero price and minimum load to come up online as soon as the temporary dip is over (0 > *opportunity_cost* ≥ - *var_cost*);
3. An offline plant expecting low prices for an extended amount of time bids a high (i.e., low-regret) bid to recover start-up costs and expected losses, in case it underestimated prices (*opportunity_cost* > 0);
4. Any other situation (except for hydro, see item 5.): no opportunity costs (*opportunity_cost* = 0);
5. Hydro plants deploy a heuristic for their optimal bidding behavior. The objective function is to maximize future profits based on given estimates on future prices[13], with the constraints that (1) a given water level target at year-end is met; (2) storage capacity is never negative given perfect foresight on future rain inflow; and (3) the capacity limit is never exceeded. If the hydro plant features a pumping system, then the same algorithm decides when to purchase electricity and to pump water into the reservoir. The heuristic first estimates monthly reservoir level targets based on expected demand (low levels in summer, high levels in winter). In a second step, these are broken down by the same logic into weekly blocks. Within each week, the algorithm sells electricity in the most expensive *n* hours and buys, if a pump is available, during the least expensive *m* hours, as illustrated in Figure 2. Factors *n* and *m* are now varied to achieve the maximum expected revenue, while considering rain inflow and the other constraints. When market prices are realized and the plan changes, e.g., because the plant did not dispatch due to overestimated prices, the model updates the weekly plan on an hourly basis.

[13] The optimization heuristic utilizes the five-year forecast of market prices, as discussed in section 2.2.

Figure 2: Schematic overview of the weekly hydro optimization heuristic



- *density_increase*$_{r,t}$: This component simulates opportunistic behavior of power plants. Based on market power exertion research[14] and the corresponding observation that market prices are beyond marginal costs and any opportunity costs in tense market situations, we introduce a price uplift based on the (expected) ratio of available capacity to demand. This can also be seen as an hourly reserve margin, which can be calculated by matching demand/load data with available supply data (available, e.g., from EEX) on an hourly basis. In tense hours, i.e., when there is only a reserve margin of about 10%, we observe a high price increase, whereas in relaxed hours at a reserve margin above 20-30%, no correction is needed. Without the *density_increase* factor, peak load power plants at the end of the supply curve could never achieve a price beyond their variable costs and, therefore, have no opportunity to recover their depreciation and other fixed cost components given the inelastic demand curve of the model. The factor also leads to a more accurate representation of peak load prices and price duration curves and can be seen, in conjunction with the hourly resolution, as a highlight of the model.
- *maximum_load*$_{p,r}$ and *least_sustainable_load*$_{p,r}$. These constants are provided to the model as input data in dependency of the power plant. Any capacity dedicated to combined-heat-and-power (CHP) and self-consumption is deducted from the output level. We assume no

[14] See HIRSCHHAUSEN et al. (2007), MUSGENS (2006), SCHWARZ/LANG (2006), and MÖST/GENOESE (2009).

subsidies between heat and electricity production, and use the thermal efficiency of a comparable plant without CHP. Deduction through CHP capacity is assumed to be constant throughout the model horizon.

2.4. Decentralized production

Capacity from non-flexible or decentralized production (wind, biomass, geothermal, solar, tidal, fuel cells) is simulated differently from the thermal capacity described in the previous section. These plants do not take part in the bidding and market clearance process. Instead, they decrease energy demand to calculate the "residual demand" used for the market clearance. In detail, the model employs the following elements:

- *Wind turbines:* Historic hourly wind production based on historic wind speeds is used as input to the model, individually for each region and split into onshore and offshore locations. Together with the installed capacity of the simulated year relative to historic capacity, the hourly production level is then calculated and deducted from demand.
- *All others:* The overall annual production as well as the hourly load patterns of these sources is treated as an external input and directly deducted from demand.

2.5. Residual demand

The model uses historic regional demand profiles that are relative to annual peak demand and applied throughout the simulation period. Next, by multiplying with the peak demand per region for the simulated year, the model calculates the actual demand per hour and per region. The total decentralized production, explained in section 2.4, is then subtracted from this regional demand. Within one region, all power generators address the demand without transmission constraints, leading to a single region-wide market price.

2.6. Market clearance

The market clearance module of the model matches supply with demand given regional constraints and import/export costs by solving for the lowest total system cost in each simulated hour. The objective function solves for each plant p in region r in hour t if it is included in the minimum cost solution; i.e., it produces ($x_{p,r,t}$=1) or not ($x_{p,r,t}$=0) and exports a certain amount ($exports_{r1,r2,t}$) per region[15]. The matrices $costs_{r1,r2}$ and $capacity_{r1,r2}$ define cross-border

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[15] Imports are modeled through exports from the exporting region, i.e., imports to region 1 from region 2 through $exports_{2,1,t}$.

electricity transport costs and capacity from region r_1 to r_2, and have a positive infinite value (for costs) or zero value (for capacity) if there is no connection between the regions. The linear objective function for each hour t is as follows:

$$\min_{x,exports}\left[\sum_p\sum_r price\_bid_{p,r,t}\cdot vol\_bid_{p,r,t}\cdot x_{p,r,t}+\sum_{r_1}\sum_{r_2} exports_{r_1,r_2,t}\cdot costs_{r_1,r_2,t}\right] \quad (3)$$

subject to constraints

I $$\sum_p vol\_bid_{p,r,t}\cdot x_{p,r,t}-\sum_{r_1=0}^{R} exports_{r,r_1,t}+\sum_{r_2=0}^{R} exports_{r_2,r,t}=res\_demand_{r,t}\ \forall r=1...R \quad (4)$$

II $$0\le exports_{r_1,r_2,t}\le capacity_{r_1,r_2,t}\quad \forall r_1,r_2=1...R \quad (5)$$

III $$0\le x_{p,r,t}\le 1\quad \forall r=1...R,p=1...P \quad (6)$$

Constraint I (eq. (4)) ensures that (residual) demand is satisfied in every region, constraint II limits cross-border exports to its capacity, while dispatch of plants is limited by constraint III.

2.7. Technical implementation

For the technical implementation of the model's core components we use the software Vensim from Ventana Systems, which was originally designed for system dynamics simulations. The model itself is a series of equations in a Vensim-specific language that are executed sequentially in each time step and displayed visually for easier comprehension. The objective function itself, however, is written in C++, in order to speed up run-time and also because Vensim does not natively support linear or quadratic optimization. Figure 3 shows the sheet managing NPV and ROI calculations for new plants based on fixed and variable costs, start-up times, capital costs, taxes etc. The “capacity investment” module described in section 2.2 is made up with this and six other sheets. These are: (1) actual construction based on the ROI as input; (2) mothballing/economic shut-down decisions; (3) restarts after mothballing; (4) retirements due to age; (5) hardwired capacity starts and shutdowns; and (6) an output formatting sheet, disaggregating the individual plants from the plant group. In total, across all five modules depicted in Figure 1, the model has about 30 sheets similar to the one shown in Figure 3.

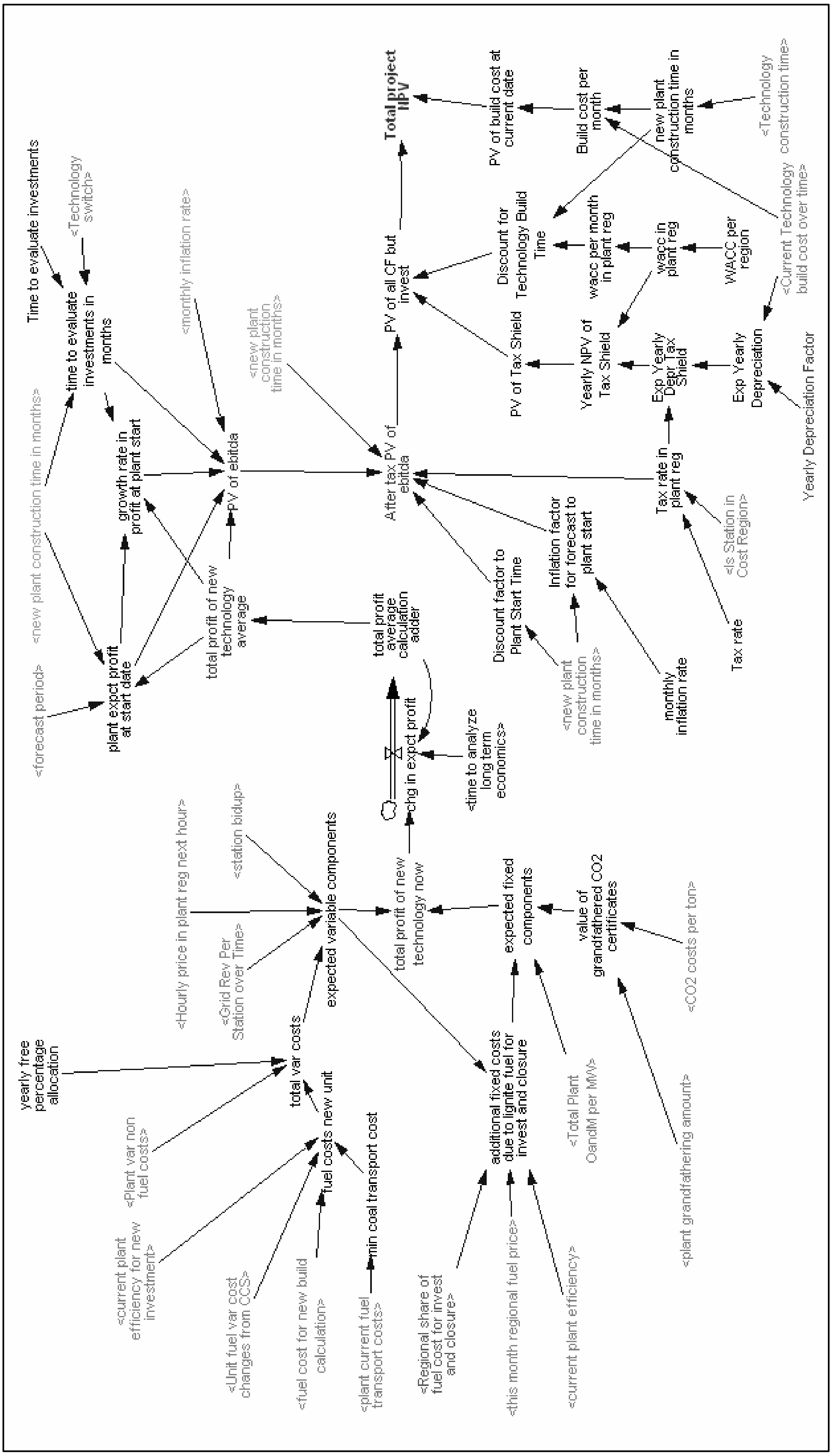
2.8. Model acknowledgements

The model presented is a further development of a model using a weekly time-step introduced in GROBBEL (1999). The model infrastructure along the key components of supply/demand matching, decentralized production, investments, cross-border flows of electricity, and aggregation/representation of results was used as a starting point for the development. From this basis, some points were re-used and adjusted to accommodate the switch from weekly to hourly time-steps. For example, the daily load curve was grouped into three levels (high, medium, and low load) applied to the whole week. In contrast, we now have 7*24 different load levels per week and region. Also, we have partly reused the module on decentralized production and the hydro-logic in the bidding module.

The other parts were redesigned: The overall objective function of section 2.6 was introduced, optimizing allocation across regions as well as the associated cross-border flows in the market clearance module. Although still based on economic NPV decisions, the investment module was largely rewritten to include components such as tax shields, grandfathered CO_2 certificates, and imperfect information. All elements related to CO_2 were added, including grandfathering of CO_2 certificates, as this was not an issue when the model was originally introduced by GROBBEL in the late 1990s. Moreover, all CCS components were included in the model. This includes input for saline aquifer, hydrocarbon field and coal-bed CO_2 storage capacity on a national level, and appropriate tracking for sufficient storage capacity. Furthermore, CO_2 emission reduction and transport and storage costs are reflected for variable cost bidding and investment decisions. In addition to the structural model changes, we extended the regional scope from Germany and its directly neighboring countries to Europe, and replaced the input data, both in terms of sources and level of detail[16]. Finally, the original horizon of the model was extended from 2014 to 2040.

[16] Germany was originally modeled as multiple separate regions, defined by the major transmission system operators and their corresponding high voltage grids.

Figure 3: Technical implementation of the NPV calculation in the model

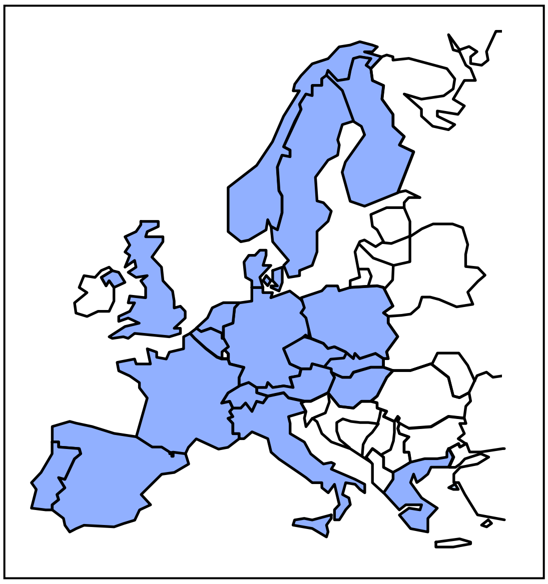


3. Input database case

3.1. Simulated countries

The model simulates 19 countries simultaneously, which are grouped into 14 regions. Specifically, it contains the EU-15 member countries without Luxembourg and Ireland, as well as Norway, Switzerland, the Czech Republic, Hungary, Poland and the Slovak Republic. Figure 4 shows the countries covered by the model.

Figure 4: Countries simulated by the HECTOR model



SOURCE: Own illustration

To optimize runtime, highly interconnected markets with few limitations on electricity imports and exports are grouped together. For example, average monthly prices in Austria's EXAA and Germany's EEX power exchanges are very similar (R^2 of 99% in 2005 and 2006). Together with Switzerland, they form the "Central European Region". Spain and Portugal are combined into the "Iberian Region" and Norway, Finland, and Sweden to the "Scandinavian Region". All other countries are considered as individual regions.

3.2. Key scenario assumptions

The assumptions for the future scenario shown in section 4 are based on the decisions of the EU 2007 European Spring Council on GHG reduction and renewables production (EU COMMISSION, 2008). It sets a target of a 20% GHG reduction by 2020 compared to 1990 levels and, in the latter directive on renewables, national targets to achieve a total final energy production of 20% from renewable energy sources by 2020. In the scenario we also allow for trading of renewable energy production across EU member states.

As the model handles renewables production capacity as external input, we use the figures from a report of the EU Directorate-General for Transport and Energy (DG-TREN, 2008) as a pathway to achieve these levels (Scenario IV, NSAT). We also use the assumptions on fuel price and CO_2 allowance price development from this report to maintain a consistent view on future development. Figure 5 shows these fuel price assumptions in €/boe[17], and Figure 6 the EU-ETS CO_2 allowance costs, which are in line with expectations from other sources, e.g., DEUTSCHE BANK (2008). All displayed costs are in this paper in real terms and based on the year 2005. For the years 2031-2040, we assume a (in real terms) constant prolongation of the 2030 value.

Figure 5: Energy price development for fuels

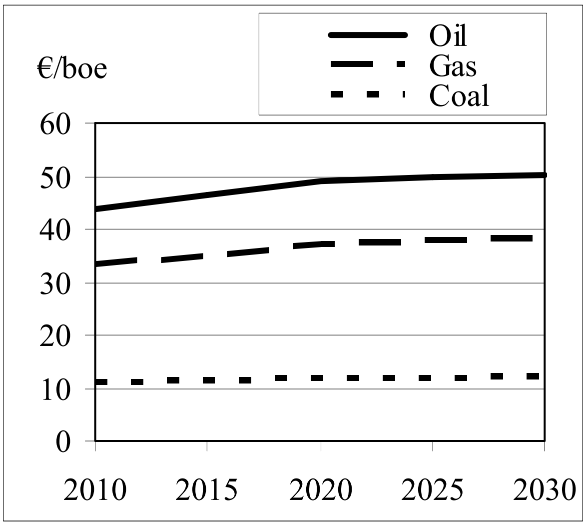
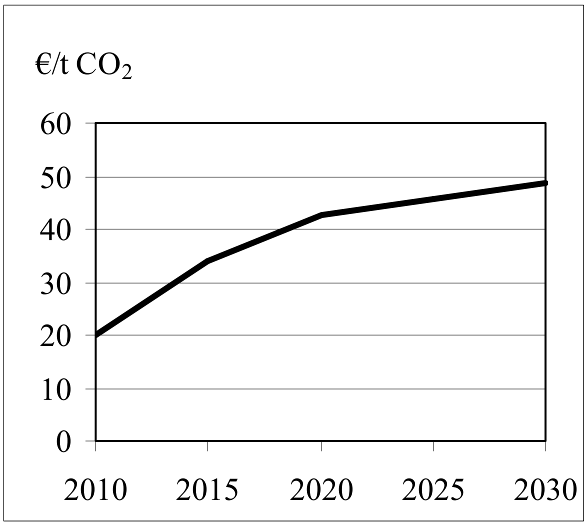


Figure 6: CO_2 price development (EU-ETS)



3.3. Historic input data

The model uses the actual historic power plant capacities, transfer capacities between countries, demand levels, CO_2 and fuel prices. Table 1 provides an overview of the key input

[17] boe = Barrel of Oil Equivalent, which expresses the approximate amount of energy released by burning one barrel of crude oil (1 boe = 6.12 GJ).

variables, their levels of detail and their sources. Plant dispatch, resulting prices, and energy flows between regions are then simulated within the model, starting from 2005.

Table 1: Historic input data to the model and data sources

Input variable(s)	Description	Source
Supply side		
Power plant data	Existing power plants with technical and economic characteristics	Platts Powervision
Transmission constraints	Available net transmission capacity (NTC) between regions in MW	National/regional TSOs, ETSOVista
Transmission costs	Transmission costs between regions per MWh	Authors' estimate at 0.5 €/MWh
Wind power turbine capacity	Installed wind capacity per country in MW	DG-TREN (2008)
Wind power production pattern	Hourly load relative to capacity	National/regional TSOs
Solar, biomass, geothermal, fuel cell and tidal power prod.	Hourly production in MWh	DG-TREN (2008), UCTE, Nordel
Hydro run-of-river power production	Hourly production in MWh	DG-TREN (2008), UCTE, Nordel
Hydro water reservoir capacity	Water storage capacity for reservoir and pump storage hydro plants	Grobbel (1999)
Hydro water reservoir inflow	Hourly rainfall patterns	Grobbel (1999)
Demand side		
Annual electricity demand	Annual net electricity consumption, excl. grid losses in TWh	UCTE, Nordel, UK National Grid/EirGrid
Demand shape	Hourly load relative to maximum load	UCTE
Macroeconomic data		
Inflation rate	Expected long-term inflation rate	Global Insight: WMM
Tax rate	Tax rate for NPVs of power plants	Authors' estimate at 35%
Capital cost	Weighted average cost of capital (WACC) for NPVs of power plants	Authors' estimate at 8%
Wage level	Wage levels for employees in power plants per country, in €/FTE	Global Insight: WMM
Exchange rate	Long-term monthly US$/€ exchange rate	Oanda (History), Global Insight: WMM (Futures)
Fuel data		
Coal price	Monthly hard coal price, ARA Hub, NWE, CIF 6000 kcal/t, Spot price	The McCloskey Group
Gas price	Monthly natural gas price, TTF Hub, Day-ahead spot price	Endex
Oil price	Monthly crude oil price, Brent, Spot price	Bloomberg
CO_2 price	Monthly CO_2 EUA allowance, end-year futures	ECX, European Energy Exchange

3.4. Exogenous future data

Whereas the model calculates the capacity of fossil fuel plants, market prices, and energy flows between models endogenously, it uses exogenous input figures for some future developments, as described in section 2. Table 2 provides an overview of these figures and the sources used.

Table 2: Future input data to the model and data sources

Input variable(s)	Assumption	Source
Supply side		
Net Transfer Capacity (NTC) development between regions		Authors' estimate
Wind turbine capacity and utilization development		DG-TREN (2008)
Future production of solar, biomass, geothermal, fuel cell and tidal plants		DG-TREN (2008)
Demand side		
Annual electricity demand		DG-TREN (2008)
Fuel data		
Coal price		DG-TREN (2008)
Gas price		DG-TREN (2008)
Oil price		DG-TREN (2008)
CO_2 price		DG-TREN (2008)
CCS data		
CO_2 storage capacities in hydrocarbon fields, aquifers and coal beds		Geocapacity (2008)
CO_2 storage cost	3.15 €/t	Average from ODENBERGER et al. (2008), MARTINSEN et al. (2007), WISE/DOOLEY (2009), DAMEN et al. (2009), JOHNSON/KEITH (2004) and MCKINSEY (2008)
CO_2 transport cost	3.29 €/t	
Characteristics of CCS hard coal power plants		
Thermal efficiency	40.4%, Net, LHV	
Investment cost	1864 €/kW	
Fixed cost	56.3 €/kW annualy	
Variable cost	1.8 €/MWh	
Commercial availability	Starting in 2020	
Capture ratio of CO_2	90%	

4. Simulation results

4.1. Comparison with historic 2005-2008 figures

To address the accuracy of the model, we analyze its ability to simulate historic plant dispatch and, as a consequence, market prices. Market prices are the key variable influencing the plant's NPV and, therefore, investment decisions. The comparison relies on average annual prices, daily price profiles, and base/peak load prices for the regions in the model. As a proxy for real-world electricity prices, we use the price notations at the major local electricity exchanges in Europe. This is easy for Germany's EEX, as it is a very liquid market[18], whereas all other exchanges have significantly lower volumes traded relative to national demand. Yet, we still rely on these sources, as we believe they are nevertheless a fair representation of electricity prices, and viable alternatives are unavailable.

Note that the only portion that needs calibration is the opportunistic bidding behavior described in section 2.3. It causes plants to bid beyond their marginal and opportunistic costs if the expected reserve capacity in a specific hour is very low, i.e., if we have a "tight" market situation. This behavior is calibrated based on 2005 data for Germany's EEX that are applied to all other model regions and years. The model therefore simulates the historic years 2006-2008 without any further calibration, and only with actual historic fuel and CO_2 prices as well as new or decommissioned plants and annual electricity demand.

Table 3: Average annual base load prices; comparison of historic values with model results in €/MWh

	EEX	Model, Germany	IPEX	Model, Italy	Power Next	Model, France	Nord Pool	Model, Scand.	OMEL	Model, Iberia
2005	46	45	59	68	47	44	29	36	54	63
2006	51	50	75	72	49	48	49	50	51	61
2007	38	33	71	48	41	32	28	33	39	36
2008	66	69	87	77	69	68	45	71	64	70
Avg.	**50**	**49**	**73**	**66**	**51**	**48**	**38**	**47**	**52**	**58**

A comparison of average annual base load prices is provided in Table 3. It can be seen that HECTOR, in terms of overall averages, is able to reconstruct historic prices quite well. The

[18] Liquidity defined as the ratio between trade volume and national electricity demand. The EEX trade volume was 1,319 TWh in 2008, more than twice that of Germany's national power consumption.

overall average price for 2005-2008 across the regions was 52.8 €/MWh in reality and 53.7 €/MWh in the model, a deviation of only 1.7%. If we exclude 2005, the opportunistic bidding was calibrated with those data for Germany, and the difference is lowered to 0.6% (54.5 vs. 54.8 €/MWh in reality).

The model's accuracy, however, highly depends on the region: For the liquid EEX market, the model achieves very accurate results compared to the other markets, with an average deviation of 0.9 €/MWh. Also for France with 3.6 €/MWh or for Spain with 5.6 €/MWh, the model is comparably accurate. For Scandinavia, on the other hand, we get an average deviation of 9.7 €/MWh, mainly due to a strong overestimation of the 2008 electricity price. However, these deviations are roughly evenly distributed in both directions, so that their impact on the European level is limited. This is especially true when considering a longer time frame, which is the case for NPV-based investment decisions covering the prices of multiple years. As this is the focus of our analysis, which provides an outlook until 2040, we expect the model to be sufficiently accurate.

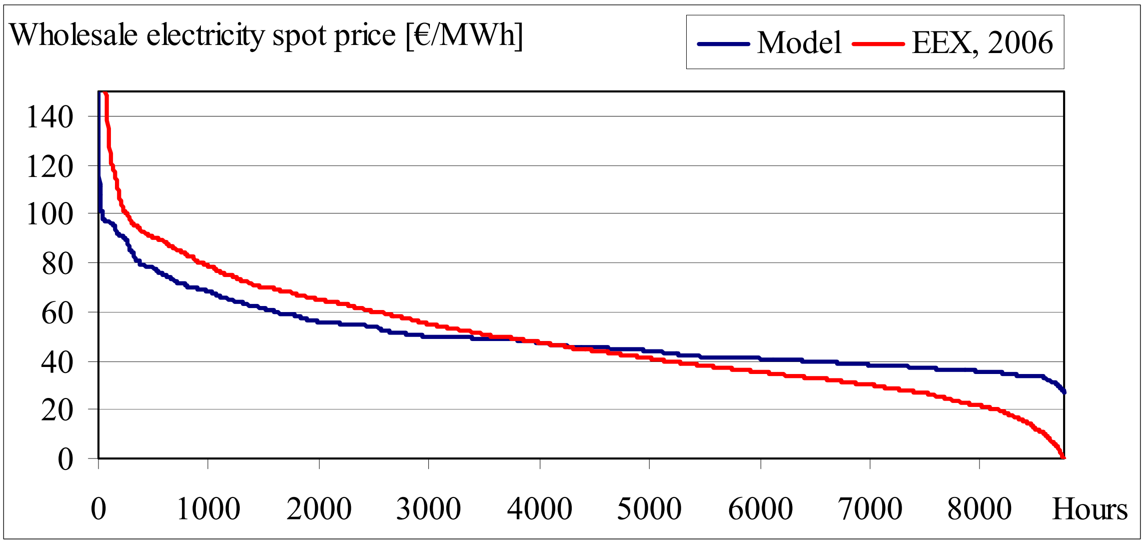
Average annual prices are sufficient for accurate revenue (and thus also NPV) calculations for base load plants, but this is not the case for peak load or mid-merit plants. Dispatch of these plants depends on peak load prices and hourly price development. We therefore compare, for each price, the number of hours in which it was achieved with a price-duration curve[19]. We find that the shape of the model's bottom-up generated curve matches the shape of the EEX curve. However, it can also be seen that the model produces a flatter curve. This effectively means that we have less variation in bidding prices. One of the reasons for a lower variation in output prices is limited variation in input prices, i.e., fuel and CO_2 permits. We use a monthly resolution, but CO_2 and fuel prices change daily, leading to different production costs on an hourly basis and to a spectrum of different price bids in reality. The model, however, uses one average price for the month, and therefore no variation in variable production costs, causing a flat price duration curve. A similar effect is the resolution of power plants. The model groups power plants if they have similar technical and economic characteristics, for the case of hard coal leading to five different groups, with efficiencies between 33% (Group "Old HC less than 300 MW") and 46% (Group "New HC"). The average value for efficiency and techni-

[19] A price duration curve is a list of hourly prices in a specific year sorted by price in ascending order. It allows an easy view on how many hours were above or below certain price levels.

cal/economic characteristics within a group is correct, but it again leads to low variance in price bids. Splitting the group into its individual components with the slightly different efficiencies would cause slightly different variable costs and hence more variation, leading to a steeper price duration curve. Besides these modeling limitations, imperfect market conditions are also a reason for the differences in shape.

Figure 7 shows the German price duration curve for 2006, which can be considered a representative year, i.e., without CO_2 price drops as in 2007, or highly fluctuating oil (and partly also coal) prices as in 2008.

Figure 7: Price duration curve for Germany, 2006, EEX versus model results



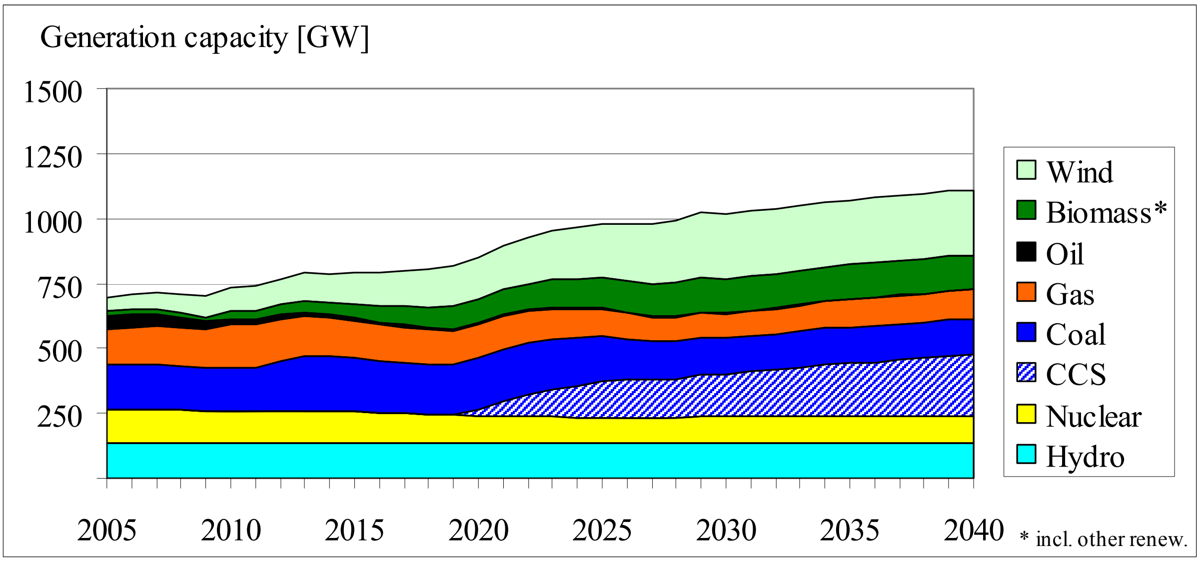
The limitations on resolution have little effect as far as long-term averages are concerned, but they do lead to a difference when compared on an hourly basis, as shown in Figure 7. This effect is similar in the other regions and years, in that the model curve is always flatter than the values observed in reality. The consequence is an underestimated difference between base and peak load prices, slightly decreasing the relative economic attractiveness of peaker plants compared to base load plants.

All things considered, we can conclude that the modeling approach and the assumptions made are suitable to resemble market behavior observed in reality. The model is able to simulate power prices very well on the annual and reasonably well on the hourly level. This is the most critical part of the model, as prices are the basis for future investment decisions. In the following section, we can now build on this to provide an outlook into the future.

4.2. Future outlook for Europe

Europe's electricity and power generation future will be primarily driven by a shift towards clean and renewable technologies. The European Commission has already decided on a GHG reduction target of 20% by 2020, compared to 1990, and the promotion of renewables to achieve a share of 20% in total production (EU COMMISSION, 2008). This greatly impacts fossil power generation, as sufficient electricity supply has to be ensured while dealing with increasing amounts of fluctuating wind power, the largest source of new renewable power generation. The capacity development of all 19 model regions depicted in Figure 8 shows the effect of the policy. We see a large increase of renewables capacity needed to achieve the 20% share in generation.

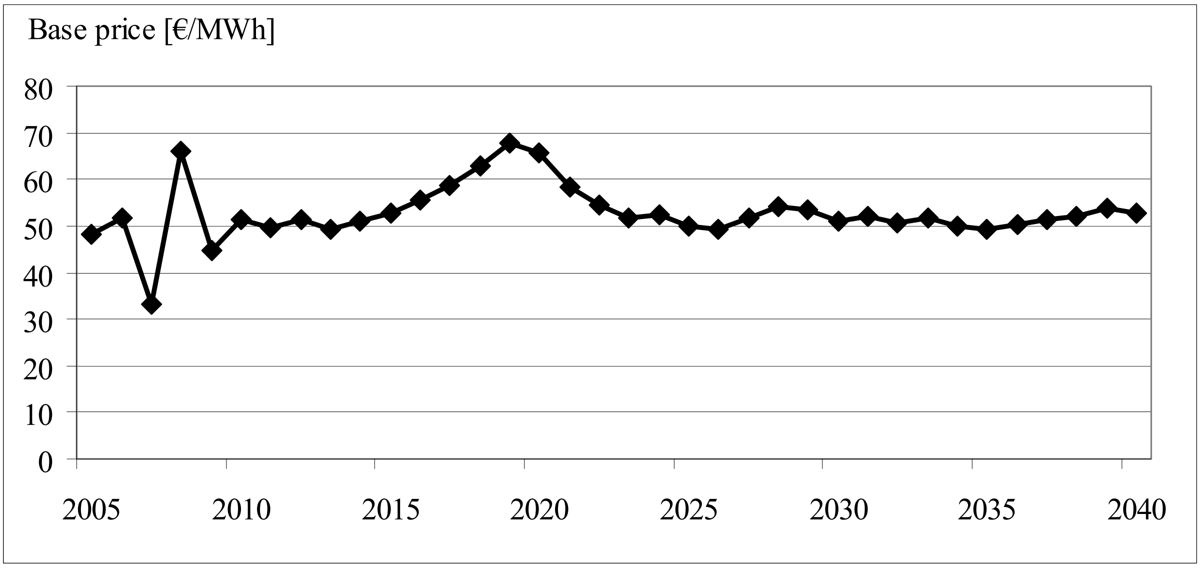
Figure 8: Installed generation capacity development across all model regions, 2005-2040



The model also builds significant amounts of CCS capacity when CCS becomes commercially available in 2020, but lowers coal- and natural gas-based production.

In Figure 9 we show the average base load wholesale electricity price development across all model regions, inflation-adjusted to the year 2005. It will hardly increase, despite relatively high CO_2 costs of about 40 €/t and an increase in natural gas prices (see scenario assumptions in section 3.2). This is only partly due to improved thermal efficiency, but mainly due to the low variable costs of renewable generation and CCS and the resulting shift of the merit order curve to the right. After CCS becomes available in 2020, we therefore see a noticeable decrease in power prices. An analysis on the country level is needed for providing further insights, which is the topic of the next section.

Figure 9: Annual base-price development, average across all model regions, 2005-2040



4.3. Future outlook on country level

The overall European development is a result of its heterogeneous countries, each with its own different plant portfolio, and their interaction with each other through transmission capacities. The energy development in every country is still individual and driven by national specifics, such as large base load lignite capacities in Germany and the Czech Republic, or vast always-on capacities in France (nuclear power) or Norway (run-of-river hydro power).

The outlook in Table 4 provides an overview on the individual development per country. For the largest region, the combined Germany/Austria/Switzerland ('D-A-CH') region, we conduct a closer look into the regional development.

In this region, nuclear and lignite would historically always operate, hard coal plants still most of the time, and natural gas/oil would operate at mid-merit and peak level. This, however, is likely to change due to two key factors: (1) new capacity through renewables and CCS that have low variable costs and (2) increasing CO_2 prices and therefore higher marginal production costs (i.e., variable costs) for traditional coal and natural gas power plants. Both effects are not favorable for these plants, as they are shifted more and more to the right of the merit order curve. Figure 10 shows this development for the years 2008, 2020, and 2030.

Table 4: Capacity development for key technologies in all model regions considered

Installed capacity [GW]	2010				2020				2040			
	RES*	Coal	Gas	CCS	RES	Coal	Gas	CCS	RES	Coal	Gas	CCS
Belgium	4	4	5	0	7	5	4	1	8	5	4	4
Germany/Austria/Switzerland	60	50	28	0	80	51	13	6	93	21	9	60
Czech Republic	3	8	0	0	5	9	0	0	8	6	0	8
Denmark	4	5	3	0	6	3	1	0	8	3	1	0
France	28	11	4	0	40	18	3	6	62	14	3	43
Greece	4	6	4	0	7	4	4	0	9	3	4	6
Hungary	1	2	3	0	2	2	3	0	4	1	2	2
Italy	22	6	40	0	34	13	40	4	45	11	40	12
Iberia	44	13	21	0	72	17	13	4	97	16	10	17
Netherlands	5	4	14	0	8	7	14	1	11	7	11	10
Poland	5	22	0	0	17	22	0	1	30	16	4	11
Finland/Norway/Sweden	51	5	13	0	58	7	9	0	75	6	16	4
Slovakia	1	1	2	0	3	1	2	0	5	0	1	4
UK	20	28	29	0	45	38	24	4	60	30	5	57

* Renewable Energy Sources (RES): Wind, biomass, hydro, solar, geothermal and other renewables

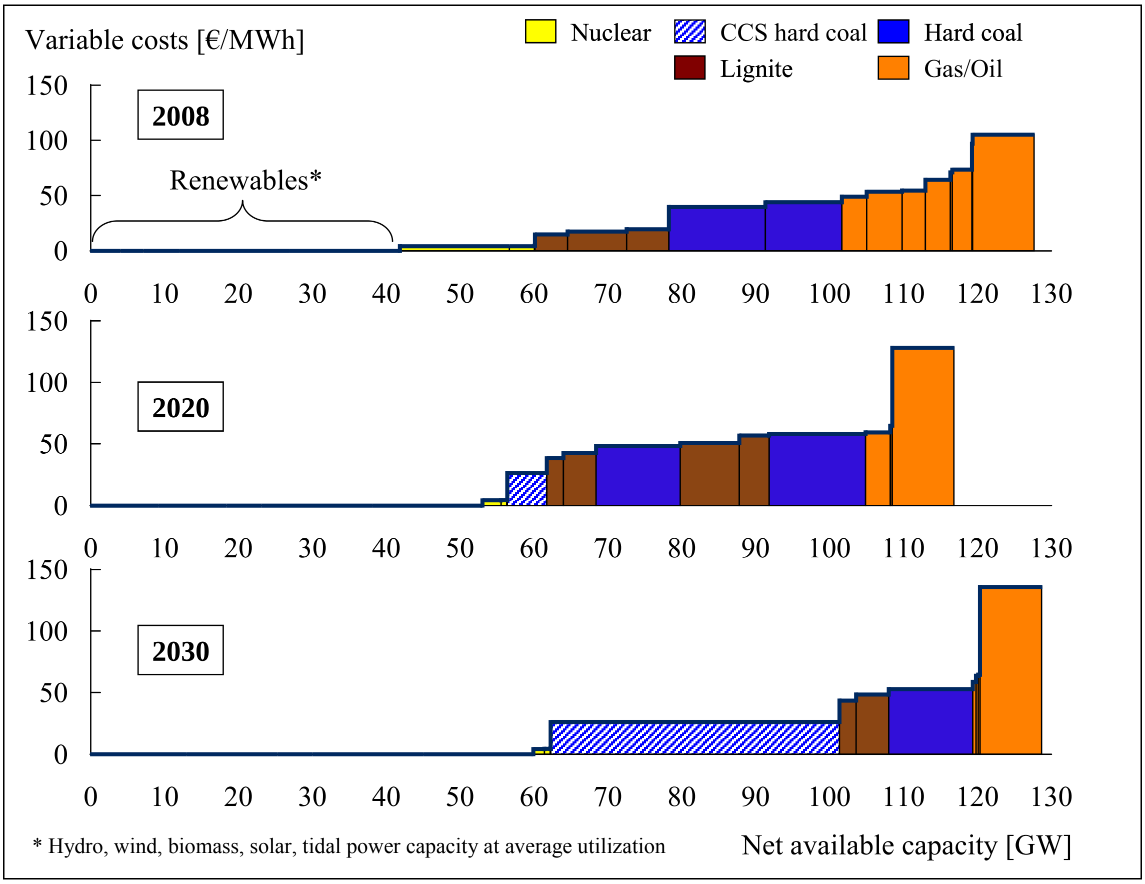
The first CCS capacity also comes on-line in 2020, the first year it is assumed to be commercially available and displaces, together with new renewables, 12 GW of old coal and 14 GW of old oil and natural gas capacity from the market. Natural gas capacity is reduced more significantly than coal capacity, this is due to steady natural gas prices and lower coal prices than the European Commission's DG-TREN expects in the upcoming years. In 2008, we have seen coal prices of 150 US$/t and natural gas prices of 25 €/MWh[20], leading to a long-run marginal cost (LRMC), i.e., full costs of a plant, including depreciation, of about 68 €/MWh for a CCGT natural gas plant and 70 €/MWh for a hard-coal power plant (PC, USC 630°C temp.)[21]. By 2020, DG-TREN (2008) expects coal prices to fall to 73 US$/t and natural gas prices to stay stable at 26 €/MWh. Even with the expected CO_2 price increase from 22 to 43

[20] ARA coal price, CIF, 6000 kcal/t; TTF gas price. See Table 1 for data sources.

[21] Load factor 80% (gas), 85% (coal); Efficiency 51% (gas), 45% (coal); Investment costs 600 €/kW (gas), 1400 €/kW (coal); 30-years' investment amortization at 8% interest rate; Fixed costs 12 €/kW (gas) and 18 €/kW (coal).

€/t and the higher CO_2 emission factor of coal, the LRMC of a natural gas plant is considerably higher (77 vs. 66 €/MWh). Therefore, we see coal being favored over natural gas in this region. Only low investment cost peaker plants remain active in 2020 and also throughout 2030. They have low utilization rates and are, due to low fixed costs, still profitable. These peaker plants are needed to satisfy demand when there is little wind.

Figure 10: Merit order curve for the Germany/Austria/Switzerland region



By 2030, we have again more renewables (7 GW over 2020) and even more CCS capacity (34 GW over 2020). Although CCS has high investment cost, its low variable costs ensure that it has a high load factor of 81% vs. only 39% for traditional hard coal and 61% for lignite plants. This makes it the most profitable technology in terms of ROI in the market, leading to the large capacity additions. The only limitation is storage space: by 2039, no more CCS plants can be built in this region, since all of the 26 Gt of CO_2 storage capacity available are reserved for the lifetime emissions of already existing plants.

The large CCS capacity has adverse effects on traditional fossil-fueled power plants, as CCS displaces them in the merit order curve. We therefore also see no new construction of regular coal or natural gas plants as they are not utilized much. However, their ongoing fixed costs are still not high enough to economically justify a complete shutdown, as was the case for old coal and natural gas capacity in the previous decade. This still ensures sufficient supply to satisfy electricity demand, but it is not at all a sustainable solution, as plants do not recover their depreciation costs in the long term. This, in consequence, leads to a lack of investment. Between 2030 and 2040 we see a continuation of the development between 2020 and 2030, namely more CCS and further shifting of the merit order curve. We also find evidence that not all of the already existing coal plants are able to recover their fixed costs, causing them to be decommissioned or mothballed. It is, however, not economical for new peaker plants to replace them, as the fixed costs cannot be recovered given the little amount of hours they are needed – effectively only when little wind production meets high demand and import capacities are fully utilized. Ultimately, starting after 2038, we therefore see power outages in such hours. Therefore, we can conclude that the purely economic market principle and the inelastic demand function that the model is built on, which explain reality currently quite well, are no longer adequate in an environment with large amounts of volatile renewable energy capacities. We expect this principle to change when markets start to get tight after 2030, and we will see much higher prices in tight hours compared to now. However, the changes and the role of regulatory bodies are impossible to predict, making modeling very difficult.

5. Summary and concluding remarks

In this article, we have introduced HECTOR, a novel electricity market model that simulates market behavior bottom-up through opportunistic, variable cost-based bidding of individual power plants into auction-based national markets for 19 European countries considering interconnection capacities. Unlike traditional approaches for long-term market modeling, we implemented the objective function on an hourly level, enabling a reduction of solution space and, therefore, a higher modeling resolution through ex-post investment decisions for power plants based on NPV and hence prices. This again is feasible through accurate price estimates driven by the high modeling resolution.

The approach chosen is able to reconstruct historic prices very well; the average price for Europe's largest countries for the years 2006-2008 was 54.8 €/MWh in reality and 54.5

€/MWh in the model, i.e., a deviation of just 0.6%, with 2005 as the training period for opportunistic bidding behavior of market players during supply scarcity. Including 2005, the deviation increases to 1.7% (52.8 vs. 53.7 €/MWh). For specific countries, the model is still fairly accurate, with deviations between 0.9 €/MWh (Germany/EEX) and in the worst case 9.7 €/MWh (Scandinavia/NordPool). On an hourly basis, the model resembles base/peak price relationships reasonably well, but creates a flatter price duration curve, primarily due to market imperfections, the lack of variation in input variables, and the clustering of similar power plant types.

As a future outlook, we modeled a scenario reflecting the renewable and GHG targets from the EU COMMISSION (2008) and energy demand and fuel cost projection from DG-TREN (2008). We find a rather stable electricity price development, despite significant CO_2 price and moderate natural gas price increases, driven by efficiency increases and substantial changes to the supply curve caused by renewable energy sources and CCS technology. For the largest model region, covering Germany, Austria and Switzerland, we expect 60 GW of CCS coming online until 2040, which is close to the theoretical limit given current expectations on saline aquifer and hydrocarbon field CO_2 storage capacities (GEOCAPACITY, 2008). CCS's great success is also driven by its ability to provide low carbon energy that is always available, unlike wind or solar energy sources. We further find traditional fossil coal- and natural gas-fired technology retiring from the market, as their capacity factor continuously decreases, and they cannot recover their fixed costs, driven by the large amounts of low marginal production cost capacity coming online through CCS and renewables. Only low fixed cost and low depreciation peaker capacity remains online, serving high demand and low renewable production periods.

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