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Annual report 2016

Oligopolistic capacity expansion with subsequent market-bidding under transmission constraints

Bi-level electricity market modeling (BEM) of Switzerland and surrounding countries

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Project goals

The goal is to investigate the investment and market behavior of producers on European electricity markets. We assume that markets will be further liberalized in the future, and large producers (players) can in principle exert market power in a competitive market. Hence, players do not cooperate to maximize the social welfare by central planning. The used model BEM (bi-level electricity market) is a market model for Switzerland and its surrounding countries, it is a game-theoretic model that can for example analyze market power.

Summary

The major accomplished work in the first project year was to build the prototype of the bi-level market model (BEM). We achieved this task and could incorporate already different load periods and even stochasticity in the model. Currently, the stochasticity consists of different scenarios on demand elasticity, and we implemented two load periods (peak and base). For the stochasticity, the players are assumed to optimize in expectation (i.e. in average) over the stochastic scenarios.
The major step this year was to implement real data into the model. The numerical model tests were reported in the BFE workshop on market modelling at the ETH in October 2016. The obtained results include that the current (over-) capacity in the surrounding countries of Switzerland is large enough that even with a complete shutdown of all nuclear plants in Germany and Switzerland, the players would not build new capacity but would rather use increased transmission.
In a statistical analysis, the wind-solar power generation was decomposed to allow for low dimensional scenario generations, which is a required approach to capture the intermittency of renewables in a game-theoretic modelling, which in turn is already numerically demanding per se. The decomposition was surprisingly straightforward by using (standard) principal component analysis, which may be an important result outside of market modelling, too.
In an empirical analysis, the elasticities of the demand curves at the EPEX market were investigated, and correlations between marketed volumes, market prices and loads were analysed (within market regions, and across regions). Moreover, a very detailed merit order for Germany was constructed and compared with averaged bid-curves on the market, which shows that the bids seem to follow closely the cost-effective merit order curve.

Work undertaken and findings obtained

Real data in the BEM model

The major work in year 2015 was to build the prototype of the bi-level market model (BEM). The major step this year was to implement real data into the model. Table 1 shows the used categories of data and the literature references. The numerical model tests are not yet fully finalized and will be reported in the BFE workshop on market modelling at the ETH end of October 2016.

Table 1: Data sets used in the modelling of BEM

Type	Description	Year	Data source
Capacity per plant type	Nominal capacity of power plants in AT, DE, FR, IT and CH	2015	ENTSO-E transparency platform

Capacity per plant subtype	Detailed capacity of gas and oil technologies (breakdown: combined cycle, gas turbine, steam turbine)	2011	Elmod (European electricity model) maintained by TU Berlin
Production / Availability factors of renewables	Production vs. capacity of intermittent renewables → Availability factors	2013	OECD – Eurostat
Technical availability	Availability factors of non-renewable plants	2011	DIW – Technical report
Potential	Technical potential of renewable technologies under social constraints	2013	JRC
CAPEX	Capital costs, lifetime of generation technologies (discount rate = 5%, parametrizable)	In the current state of modelling, the year 2010 (i.e. today's) values are used	DIW – Technical report
VAROM	Variable Operation & Maintenance costs	In the current state of modelling, the year 2010 (i.e. today's) values are used	DIW – Technical report
FIXOM	Fixed Operation & Maintenance costs	In the current state of modelling, the year 2010 (i.e. today's) are used	DIW – Technical report
Efficiency	Energy efficiency of technology	In the current state of modelling, the year 2010 (i.e. today's) values are used	DIW – Technical report
Fuel price	Gas, Oil, Coal (without CO2 price)		DIW
CO2-price	20EUR/tCO2 (tentative)	to be finally agreed in harmonization with University of Basel	DIW – Technical report
Demand amounts	Demand amounts for different load periods	2015	ENTSO-E
Demand elasticities	Demand elasticities for different load periods	2015	EPEX, and info in master thesis of Christoph Groh
Solar and Wind profiles	Hourly wind and solar generation profiles for the countries	2015	ENTSO-E transparency platform
Transmission capacities, reactance	Aggregated line capacities between countries	2013	JRC

After initial tests of the model in the first project year with rather generic data, the following generation technologies are incorporated in the modelling:

- Lignite power plant
- Coal (black) power plant
- Oil-fired steam turbine
- Oil combustion turbine
- Oil combined-cycle turbine
- Gas-fired steam turbine
- Gas combustion turbine
- Gas combined-cycle turbine
- Nuclear plants (new generation)
- Biomass (generic, because lacking data, includes waste and biogas)
- Hydro Run-of-River
- Hydro Dam (includes pumped-storage)
- Wind (only onshore, because offshore technical potential is relatively low, even in the German region)
- Solar (without solar thermal power, which is negligible today and is likely not cost-effective in the future)

Some technologies are currently excluded, because today's deployment is very low and their potential is foreseen to stay low or is very uncertain: Tidal power generation, and geothermal power. Coal gasification is also excluded because the authors believe that the technology characteristics in terms of cost competitiveness (higher efficiency versus higher capex) render this technology comparable to conventional coal technologies, which is represented in BEM.

Analysis of wind-solar power generation

In a statistical analysis, the wind-solar power generation was decomposed to allow for low dimensional scenario generations, which is a required approach to capture the intermittency of renewables in a game-theoretic modelling, which is already numerically demanding per se. Details are presented below.

Analysis of price- and demand-curves at the EPEX day-ahead market

In an empirical analysis, the elasticities of the demand curves at the EPEX market were investigated, and correlations between marketed volumes, market prices and loads were analysed (within market regions, and across regions). Moreover, a very detailed merit order for Germany was constructed and compared with averaged bid-curves on the market. Details are presented below.

Achieved results

1. Model runs with real data with the BEM model

- Realistic data of AT, DE, IT, FR and CH was implemented in the model (see above)
- The BEM model was run with realistic data of the market areas, and in most of the runs, the algorithm did converge to a numerical optimal solution, that is, an optimal configuration of capacity expansion and of market trading in two load periods and for each of the regions.

The numerical results with real data will be presented end of October 2016.

2. Empirical analysis of EPEX spot prices and demand-bids for different market areas

In an empirical analysis, the demand and price curves of the EPEX day-ahead spot market were investigated for a recent years (most of the analysis is for 2015) and for the market areas Switzerland (CH), France (FR), and Germany + Austria (DE+AT). The analysis of the demand curves and the associated price elasticities will enter in the modelling of BEM. In particular, the following dependencies were investigated.

- **Price and (market-)volumes over a day:** In all of the investigated market areas**,** the price for each day-hour is averaged over 2015. High prices are observed in all areas approximately at 8 and 19 o'clock. On the other hand, the variation in traded volumes over the day is different in different regions: In FR and CH, high volumes are traded in the morning and in the evening, whereas in DE+AT high volumes follow the PV generation profile.
- **Price–Volume correlation inside a region:** Daily (averaged) volumes and prices over year 2015 were considered. For these daily data, no correlation between price and volume could be detected. This contradicts traditional economic analysis, which is not uncommon for power markets. In an extension, each hour of the day may be investigated separately.
- **Price-Price correlation across regions:** Daily (averaged) prices over year 2015 were considered. The highest correlation of (daily averaged) prices was observed between CH and FR, where in a regression model the R^2-coefficient yielded 72%, whereas 33% were observed between CH and DE+AT and 50% between FR and DE+AT. Clearly, this analysis should be further enhanced in an extension by sub-setting the data points to winter/summer, peak/off-peak time.
- **Volume-Volume correlation across regions:** The daily (averaged) volumes in year 2014 were only very weakly correlated across regions. A conjecture is that if a region produces more, the other regions produce less, that is, they import (all other factors being constant), for example between CH and FR. Note that the hourly profiles of CH and FR of traded volumes are nevertheless heavily correlated (see above). Hence, further investigations may be of interest.
- **Volume-Demand correlation inside a region:** In a first analysis, volume-demand correlation was investigated on hourly chronological data for 2015. Surprisingly, there is no high correlation in market area CH and in FR between demand and traded volume (for a specific hour). In DE+AT, a regression exhibited a R^2-coefficient of 26%, which shows some correlation, which may be explained by the higher share of demand traded in DE+AT (i.e., 46% in 2015, whereas only 23% in FR, and 37% in CH).
In a second regression, the correlation was tested for each hour of the day in 2015 separately, and no correlation was found at all. Hence, it seems that currently the market is used for additional short-term trading, whereas the forecasted domestic demand of a supplier is covered beforehand off-market, such that the (bulk) height of demand has no influence on the additional trading.

The elasticities of the (inverse) demand curves on the market were also investigated. For this, the derivative of the demand with respect to the price must be calculated approximatively. This is difficult for the observed hourly (downward sloping) inverse demand curves, which are extremely steep at high prices for low demands, then somehow linearly going down at moderate prices for many demand bids and then going steep down again to negative prices for excess demand bids. In the master thesis, this problem was tackled by taking logarithms (to tackle negative prices and because the elasticity is measured in relative units), and with a line-search to find the (approximatively) linear part of the inverse demand curve. The line searched started from the left of the inverse demand curve at a relatively high price of 70 EUR and searched for the successive pair of bids where the difference on the horizontal axes is larger than 10 kWh, that is, where the downward slope starts to decrease. This bid defines (heuristically) the start of the "linear" part until the realized price/volume pair, which is used as the right end-point of the linear part. The 10 kWh and the 70 EUR where determined by heuristic trials. It was found that this linear part is approximately 1 GWh for Switzerland and France markets, and 2 GW for Germany + Austria.

- **Elasticity-Elasticity correlation over time (auto-correlation) inside a region:** The correlation of the elasticity across chronological hours was evaluated in 2015. It could be shown that the correlation of elasticity is very high in all market areas (FR, DE+AT, CH). Hence, it seems that the market situation changes slowly on the demand side over subsequent hours. In a possible extension, it would be nice to evaluate the correlation between peak- and base-load hours (instead of chronological hours).

- **Elasticity correlation across regions:** The hourly 2015 data showed no significant correlation between countries. Hence, it seems that the steepness of the demand bids on the markets are independent and idiosyncratic for each market area.

- **Elasticity-Price correlation inside a region:** For each of the 24 hours, the elasticities and prices were averaged over all days of year 2015. Highest elasticity was observed in the early morning in all market regions. Another important observed result is that prices and elasticities are negatively correlated; see Figure 1.

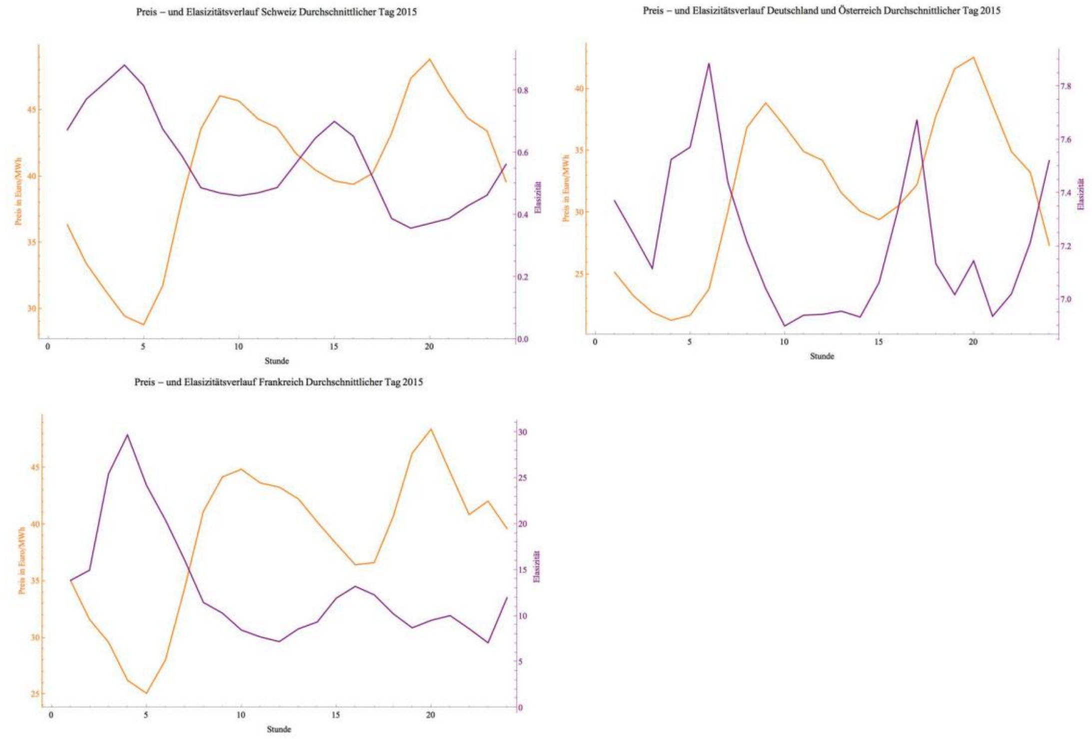

Figure 1: Prices and demand-elasticities, for each hour, averaged over the days of year 2015, for each region. Up/left: Switzerland, Up/right: Germany + Austria, Down: France.

A possible explanation for the inverse relationship is as follows: When prices are high, then volumes are usually also high on the electricity markets. Hence, high volumes are demanded despite prices are high in these hours, which is an anomaly in traditional economy. In these hours, demand bids are only placed if really absolutely necessary, and must be placed independently on benevolent price-signals, or in other words, the demand elasticity is low. Hence, there seems to be opportunities for market power in those hours. This shall be investigated further.

3. Empirical analysis of merit order curve of Germany in 2015

In an empirical analysis, a synthetized merit order curve of Germany was compared with the supply curve on the market. Because the share of traded electricity in DE+AT market area is relatively large (and trading in AT is small), it is expected that a merit order curve may somehow "match" the supply curve in absence of significant amounts of market power. First, this was investigated over a yearly average by constructing

1. a merit order curve for Germany (Figure 2), taking into account:
   - 1563 power plants
   - Estimated variable costs, CO_2-costs, Fuel costs
   - Efficiency, based on the age of the plant in each category
   - Actual availability (historical production / net capacity), which is usually lower than technical availability.

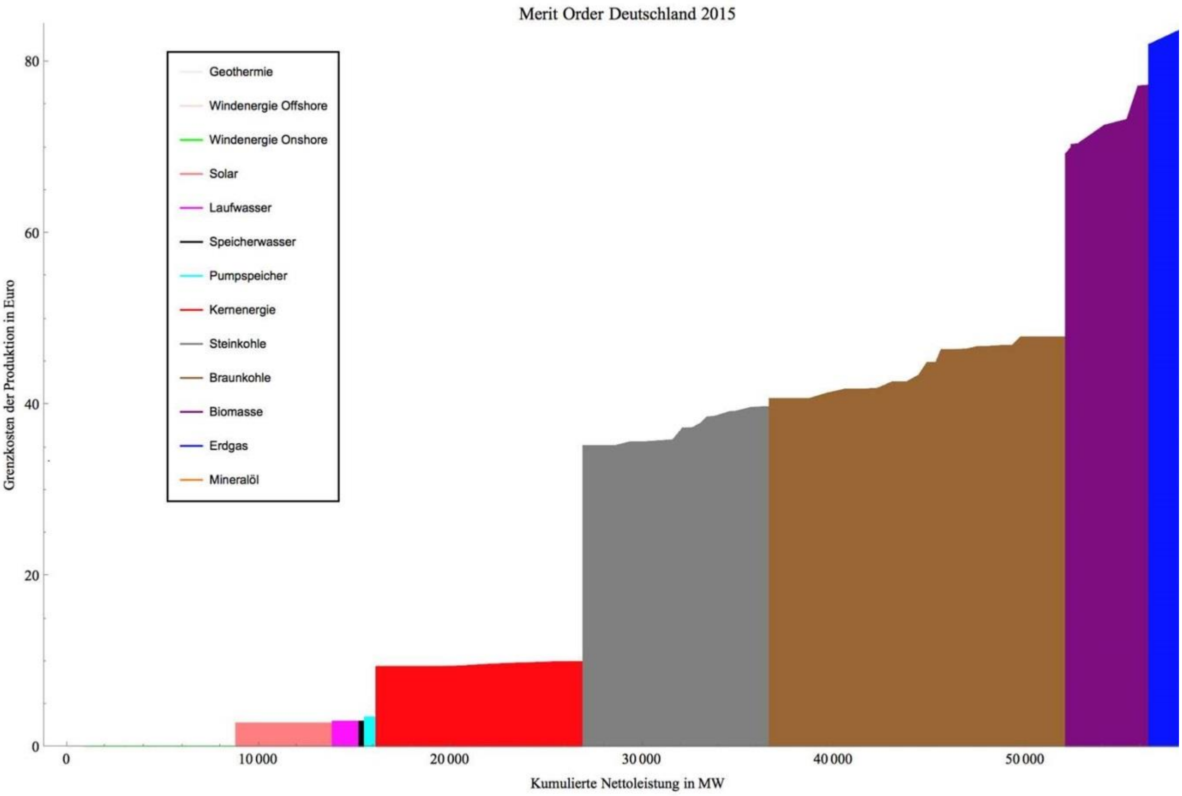

Figure 2: Average merit-order curve of Germany in year 2015 (with renewables, and actual availability)

2. Averaging all the supply curves on the day-head EPEX market over all hours of 2015 for area DE+AT.

The result is shown in Figure 3. In the considered average, the supply-bid curve has a similar shape than the merit-order curve, which is consistent with the view that the submarket (EPEX) is in agreement with the price-building process on the whole electricity market (including OTC) because all traders are usually present on both markets. Neglecting the variability of renewables, it seems that the baseload plants are on-average bidding above their costs in 2015, whereas peak-load plants are bidding (as average) below costs.

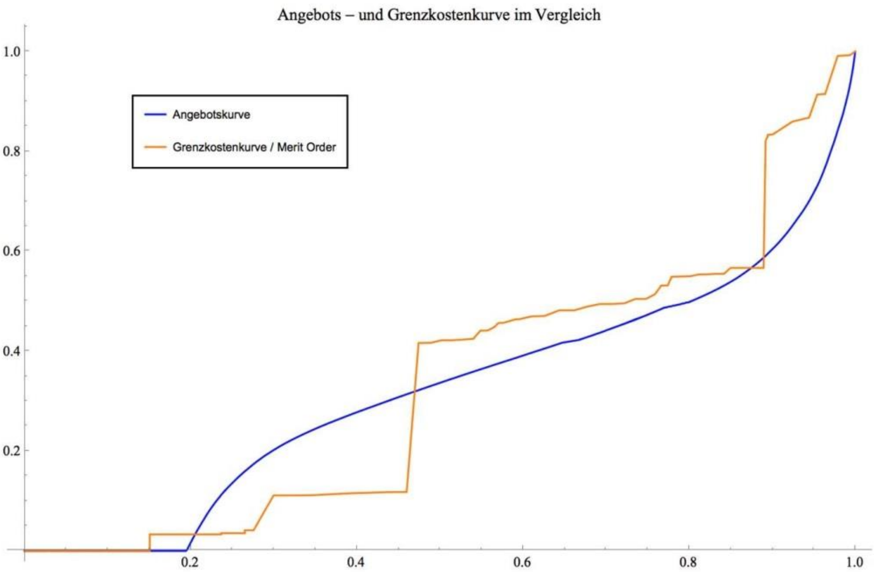

Figure 3: Averaged supply curve and averaged merit order curve for Germany in year 2015. y-axis shows range [–80 ,100] EUR/MWh, with negative values set to 0 EUR/MWh. Axes are scaled to 100%

These findings were also tested for each hour separately for the year 2015. As a strong simplification, the merit order curve was modified only by removing solar during night (clearly this can be improved, but more details are considerably more data-intensive). While for the yearly averaged curves (Figure 3) the mean-square-error between the merit order curve and the supply curve is approximately 12%, the error is 16% on average on the hourly curves, with only a fraction of 14% of hours above 20%.
The above analysis could be extended in many ways, for example, export/import of the trading area is not taken into account.

4. Statistical decomposition of wind and solar availability

The underlying data for the statistical decomposition for the analysis was the solar and wind generation profiles for Germany in 2012–2014. The original data source for the analysis was the open-source data-provider EEXWATCH (eventually, the data will be taken from ENTSO-E by the end of this year). The correlation between hourly solar and wind in 2012–2014 is shown in Table 2, which exhibits the well-known pattern: Wind and solar are slightly negatively correlated, hence they are slightly complementary power sources, and solar is correlated with demand, which alleviates the disability to produce during nights. Figure 4 and Figure 5 show the availability over time: Whereas solar has the usual bell-shape pattern across all seasons, wind is more prominent in the evening or during nights (in winter), which contributes to the negative correlation with solar.

Table 2: Correlation between hourly data of solar power, wind power, and electricity demand in Germany during 2012–2014

	Solar	Wind	Demand
Solar	1	-0.13	0.45
Wind		1	0.088
Demand			1

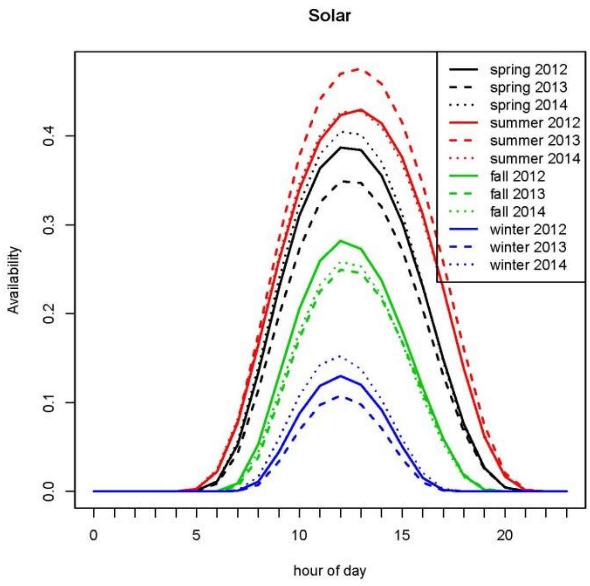

Figure 4: Solar availability in 2012–2014 across seasons

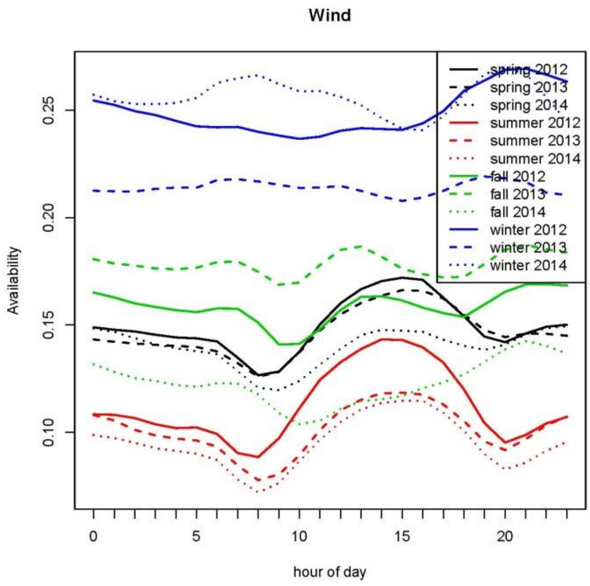

Figure 5: Wind availability in 2012–2014 across seasons

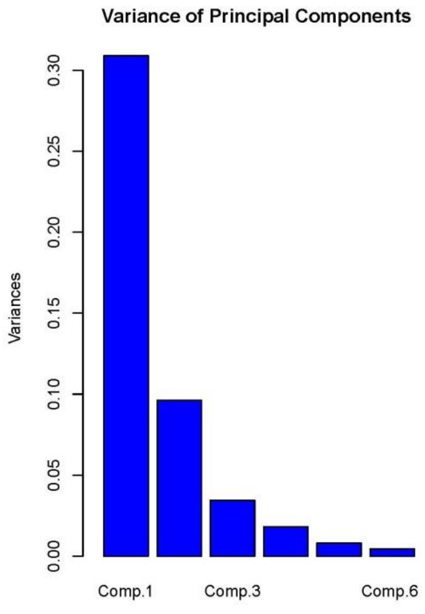

Figure 6: Screeplot of principal components of the (24+24)-variate series of hourly wind and solar power generation during a year

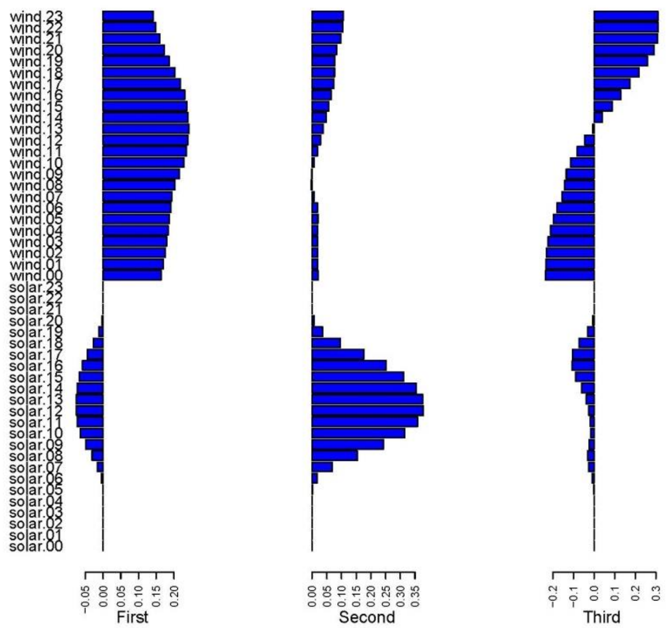

Figure 7: Factor of loadings of the first three principal components of the (24+24)-variate series of hourly wind and solar power generation during a year

We considered the 48--variate time series of hourly wind and solar generation (24h wind + 24h solar = 48h) over yearly seasons or full years and performed a principal component analysis on this multivariate time series. In Figure 6 and Figure 7, results for spring (Mar + Apr + May) in 2012–2014 are shown. The first two (three) principal components describe 85% (92%) of total variance. Hence, these components can be used for low-dimensional scenario generation with a factor model. The principal components in

Figure 7 have the following interpretation. Most of the variance is in the first principal component, where the solar bell-shape is on one side and (negatively correlated) the wind on the other side, with a wind-maximum in the afternoon. The second component says that if there is more solar, there is also more wind in the late evening (which could correspond more to a typical situation in winter). **Figure 8** shows 64 (64 = 8 * 8) generated scenarios by varying and combining the first two factor loadings. The variation of the factors is assumed to be normally distributed, which is discretized by a binomial distribution with 8 realizations. In experiments, the principal components with raw data gave the best results (i.e. without de-meaning or taking logarithm) having the drawback that negative values have to be discarded (normal distributions have negative values).
The aforementioned analysis allows incorporating the variability of intermittent renewables with a numerically tractable number of scenarios into Nash-Cournot game-theoretic optimization problems.

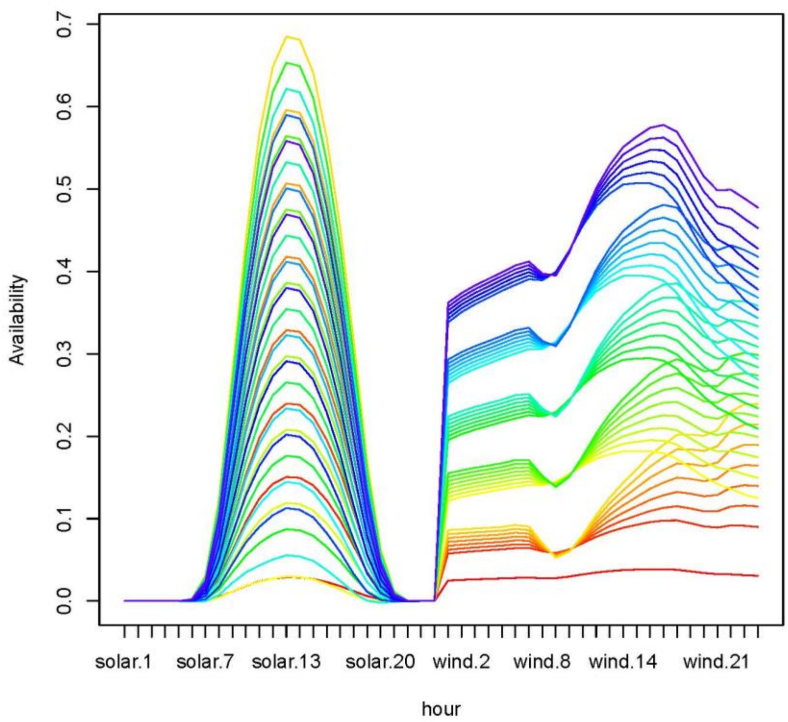

Figure 8: Scenarios of wind-and solar generation profiles generated with the first two principal components from the factor analysis.

5. Theoretical evaluation of solution methods

Several alternative solution methods for EPEC problems proposed in the literature were studied. It still seems that the chosen iterative diagonalization approach is the most robust algorithm to work with real-world numerical data. That is:

a. Solve the (simple) social welfare-maximization problem. Use the obtained solution as a starting solution for (b.).

b. Solve the open-loop model (investment and production is decided in a single decision, i.e. single step modelling). Use the obtained optimal solution as starting solution for (c.).

c. Solve the (two-stage) EPEC with a diagonalization technique across the players. That is, each player solves subsequently an MPEC, given the fixed decisions of the other players (Gauss-Seidel type iterations).

National cooperation

The Paul Scherrer Institute is collaborating with the **Chair of Quantitative Business Administration of the University of Zurich**, and the work was presented in several internal workshops.

2016
A master thesis of the economic faculty of the University of Zurich was executed during Jan 2016 – Jun 2016. The topic was to analyze today's behavior of market players (see references).

With the **University of Basel** two workshops were held in 2016. In the first workshop (where BFE was also present) the modeling harmonization was prepared. In a second workshop, the data that can be harmonized was determined. The data exchange is now agreed and should be finalized Feb 2017.

Evaluation 2016 and outlook for 2017

Fulfillment of project plan/deliverable in 2016

The milestone of 2016 according to the project plan is fulfilled: A working prototype of the numerical model yielded results with real data. So far, scientific feedback on the modeling approach is very encouraging, and it seems that we have stired interest in bi-level modeling, which is a relatively new approach within the scientific community in Switzerland.
We have also intensified the harmonization with University of Basel, were two workshops have been held.
The accomplished master thesis yields the basis for the data input of demand elasticities and provides indications how prices and merit-order curves are correlated. Prof. Schmedders indicated that an in-depth follow-up analysis could be beneficial.

Project outlook for winter 2017

- Incorporation of variable demand elasticity and of variability of intermittent renewable generation across two load periods
- The DC flow model of the transmission constraints will be replaced in a test by net transfer capacities
- The whole numerical model with real data will be tested numerically extensively

Project outlook for 2017

- Policy constraints
- Influence of financial risk constraint of the players

- Extensions: More active role of TSO; fringe region (additional, aggregated players); multiple time steps (phase-out (economical/technical) and refurbishment); storage between load periods.

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Contents

Project goals....3
Summary....3
Work undertaken and findings obtained....3
National cooperation 13
Evaluation 2016 and outlook for 2017.... 13
References 14
Contents 15
List of abbreviations 16

List of abbreviations

AT	Austria
BEM	Bi-level electricity market
CAPEX	Capital expenditure
CH	Switzerland
DE	Germany
DE+AT	Coupled market area of Germany and Austria
EPEC	Equilibrium problem with equilibrium constraints
EPEX	European power exchange
FIXOM	Fixed Operating & Maintenance costs
FR	France
IT	Italy
MPEC	Mathematical program with equilibrium constraints
OCESM	Oligopolistic capacity expansion with sub-sequent market-bidding under transmission constraints
OTC	Over-the-counter market (not EPEX)
TSO	Transmission system operator
VAROM	Variable Operating & Maintenance costs