Impacts of the Introduction of CO_2 Price Floors in a Two-Country Electricity Market Model

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Abstract

The recent low of CO_2 prices in the European Union Emission Trading Scheme have triggered a renewed discussion, whether the introduction of a CO_2 price floor would lower investor uncertainty and thus trigger more investment in low-carbon electricity generation. We compare the effects of a CO_2 price floor on the dynamic investment pathway of an interlinked two country electricity system with a common CO_2 emission trading scheme using a long-term focused agent-based model. Four cases are distinguished: No CO_2 price floor, a CO_2 price floor unilaterally levied as a complimentary variable tax on production in only one country and a common CO_2 price floor in two countries. Preliminary results indicate that while a national price floor reduces price variance in the introducing country, the overall CO_2 price variance increases. A common CO_2 price floor was found to decrease overall price variance.

Keywords:
CO_2 Policy, EU-ETS, CO_2 price floor, ABM

1. Introduction

The recent low of CO_2 prices in the European Union Emission Trading Scheme have triggered a renewed discussion, whether it provides enough incentives to push forward the energy transition.The introduction of a CO_2 price floor has been proposed as a policy measure to lower investor uncertainty and thus induce more stable investment in low-carbon electricity generation [18]. A national implementation of a price floor is for example discussed in the U.K. [15] as a national policy measure to promote low carbon investments. The effects of such policies have however, not been extensively researched yet.

We compare the effects of a CO_2 price floor on the dynamic investment pathway of an interlinked two country electricity system with a common CO_2 emission trading scheme using a long-term focused agent-based model and a Monte-Carlo simulation. Four cases are distinguished: No CO_2 price floor, a CO_2 price floor unilaterally levied as a complimentary variable tax (as proposed in [18]) on production in only one country (one case per country) and a common CO_2 price floor in two countries. Preliminary results indicate that while a national price floor reduces price variance in the introducing country, the overall CO_2 price variance increases. A common CO_2 price floor was found to decrease overall price variance.

2. Related Work

While CO_2 price caps have been more often discussed in policy and literature [7], the discussion on CO_2 price floors is, according to Wood, more recent and not as well developed [18]. He states that in principle three models for CO_2 price floors exist:

- Buy back of licenses by the administrator (as proposed in [10])
- A reserve price when emissions are auctioned [9, 11]
- A complimentary tax by the emitter, so that the sum of the emission allowance and the ex-

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tra fee is equal to the desired minimum CO_2 price floor.

Wood concludes that the first and the second option are not applicable for national solutions within interlinked CO_2 trading schemes (or the EU ETS), since the first creates potentially unlimited liabilities and the latter might lead to emitters buying permits elsewhere, thus reducing his own source of income.

We propose to analyse this policy measure with the help of an agent-based model. While agent-based modelling is more common for spot-market simulations of electricity markets and attached CO_2 markets (see for example [17] for an overview, or [8]), agent-based modelling is only being applied more recently to long-term policy issues, such as CO_2 cap and trade schemes and CO_2 taxes [2, 1] or for comparing different CO_2 emission allocation schemes [14].

3. Model Description and Assumptions

We use the long-term focused agent-based model *D13N*[1], based on the AgentSpring modelling framework [3] and prior work in [2, 16]. In order to enable Monte-Carlo simulations of the entire model, leading to an exploratory analysis, several simplifying assumptions needed to be made, to keep the model computationally efficient.

The yearly electricity demand is represented as a band of 20 segments with fixed decreasing loads and varying length per segment (from peak to base-load), representing a load duration curve in a stepwise approximation. The CO_2 price is found by iterations between clearing the electricity market segments and adjusting the CO_2 market price, so that the emissions cap is reached, thus arriving at an efficient market equilibrium in an iterative approach. Fuel prices, as well as the electricity demand are modelled as stochastic trends, which are price-inelastic.

The evolution of the power plant mix is an endogenous result of individual agents' investment decisions in each annual time step, taking into consideration expected electricity prices, which the agents arrive at by individual bottom-up estimation of the merit order, as well as expected demand, expected fuel and CO_2 prices, which are estimated by each agent from past observed data. In case of multi-fuel power plants, agents determine the optimal fuel mix for each bidding round using a linear program.

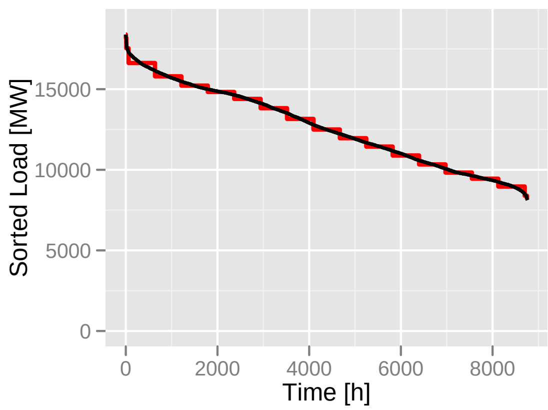

Figure 1: Load duration curve of the Netherlands in 2010 and its segment-based approximation

In the following the most relevant parts of the model are described and defined in more detail. A complete technical description of the model can be found in [16].

3.1. Interlinked Electricity Markets and CO_2 Market

The electricity spot market is abstracted from an hourly power system model by representing demand in each country as a stepwise approximation of the load duration curve. Yearly demand is thus represented as a band of 20 segments from base to peak load, which each segment having a fixed demand, thus grouping hours in the year with a similar demand (see Figure 1). The segment length can be varied, so that a good approximation of the load duration curve is achieved. While this abstraction has its disadvantages, it allows for shorter model run times, and thus enables us to do several hundred Monte-Carlo runs of the entire model in an acceptable amount of time. In the following the iterative market clearing process is described in more detail:

1) The generators bid into each of the segments, using one price-volume pair per segment and power plant. The electricity market they bid into is determined by the location (country c) of the power plant p.

$$b_{c,s,p,t} = (p_{c,s,p,t}, V_{c,s,p,t}) \qquad (1)$$

[1] Short for Decarbonisation, since there are 13 letters between the D and the last n.

Variable	Unit/Content	Description
t	a	Time step, in years
c	{A,B}	Country index
$S_{s,c}$	(D_s, l_s)	Segment is a tuple of demand and length
$D_{s,c}$	MW	Demand in Segment S
l_s	h	Length of Segment S (identical for both countries)
s	$\{1,\dots,20\}$	Segment index
$LDC_{c,t}$	$\{S_{c,1},\dots,S_{c,20}\}$	Load Duration Curve with 20 segments
$b_{c,s,p,t}$	$(p_{c,s,p,t}, V_{c,s,p,t})$	Bid into country c, segment s, year t for power plant p, excluding CO2 cost
$p_{c,s,p,t}$	$€/MWh_{el}$	Bidded price
$V_{c,s,p,t}$	MW	Bidded capacity
$\rho_{c,s,t}$	$€/MWh_{el}$	Segment clearing price
p	$\{1,\dots,P\}$	Power plant index
e_p	t_{CO_2}/MW	Emission intensity of power plant p
p_{CO_2}	$€/ton$	CO_2 Market Price
$F_{CO_2,c,t}$	$€/ton$	CO_2 Price Floor in country C
$T_{CO_2,c,t}$	$€/ton$	Complimentary CO_2 tax in country C
$c_{p,fuel}$	$€/MWh_{el}$	Variable fuel costs of power plant p
p_f	$€/MWh_{th}$	Price of fuel f
$s_{p,f}$	MWh_{th}	Amount of fuel in fuel mix
$\eta_{p,e}$		Efficiency of power plant p
$a_{s,p}$		Segment dependent availability of power plant p
m_g		Price mark-up of generator g
$\hat{r}_{p,s,t}$	h	Expected running hours of power plan p, in segment s, in year t
I_p	€	Investment cost of power plant p

Table 1: Notation

2) The bids of the power generators are universally adjusted for a given, identical CO_2 price p_{CO_2} and the complimentary CO_2 tax $T_{CO_2,C}$, as well as the the emission intensity e_p of the power plant, so that the costs of CO_2 emission are accounted for in the bid.

$$b^{CO_2}_{c,s,p,t} = (p_{t,c,s,p} + (p_{CO_2} + T_{CO_2,c,t}) \cdot e_p, V_{c,s,p,t}) \tag{2}$$

The complimentary tax is set such that the minimum CO_2 price floor $F_{CO_2,c}$ in Country c is guaranteed:

$$T_{CO_2,c} = \max(0, F_{CO_2,c,t} - p_{CO_2}) \tag{3}$$

3) The two electricity markets, which are physically coupled by an interconnector with capacity I_C are then cleared (via implicit market splitting) and the highest accepted bid (that is needed to satisfy demand) $b^{CO_2,*}_{c,s,p,t} = (p_{c,s,p,t}, V^*_{c,s,p,t})$ sets the market clearing price $\rho_{c,s,t}$ for country c and segment s. In case demand $D_{c,s,t}$ in segment s cannot be satisfied, the clearing price is set to the value of lost load.

4) After clearing the market the resulting CO_2 emissions are determined, based on all accepted bids.

$$E_t = \sum V_{c,s,p,t} \cdot e_{p,t} \tag{4}$$

In case the emissions are approximately equal to the CO_2 cap (within a tolerance band of $\pm 5\%$, which can be interpreted as consumption/saving of CO_2 allowances from previous/for future years), or in case a price minimum (0 or global price floor) is reached, the market is considered cleared, and the simulation continues. Otherwise a new CO_2 price p_{CO_2} is defined via an iteration algorithm, and steps 2) through 4) are repeated until a stable equilibrium price is found, or the maximum iteration number is reached.

3.2. Generation technologies

Twelve power generation technologies have been implemented in the model (cf. Table 2), which are available to the generator agents. Investment costs, maintenance costs, operational costs, power plant efficiencies as well as technological learning projections (affecting efficiencies and investment costs) have been modelled after the IEA World Energy Outlook 2011 New Policies Scenario [12]. Additional assumption were made regarding the power plant capacity, technical life time, CO2 capture efficiency [4], depreciation time and for co-firing. Due to the load duration curve approximation, model-specific assumptions needed to be made for some technologies. Minimum running hours serve as an investment decision approximation for plants with longer ramping times, and the intermittency of some renewable power plants is reflected the base and peak dependent availability, i.e, a wind turbine only produces 5% of its nameplate capacity during peaks. In between the base and peak segment, the segment-dependent availability $a_{p,s}$ is varied linearly. These assumptions are summarized in Table 2. The initial generation portfolios are broadly modelled after Germany and the Netherlands, but any other generation mix could be easily modelled as well.

3.3. Power plant operation and spot market bidding

The fuel mix of multi-fuel power plants is determined at the beginning of each year, implicitly assuming that this is the time that fuel supply contracts are concluded. As a consequence of this assumption the CO_2 price is not known, and the agents take the previous year's CO_2 price as a best estimate to calculate their optimal fuel mix. This is done via a linear program taking into consideration current fuel prices (which are known), last year's CO_2 price, the power plant efficiency and the fuel mix constraints given in Table 2. The resulting variable fuel costs per MWh_{el} for power plant p are then determined as the weighted average of the fuel prices:

$$c_{p,fuel} = \sum_f \frac{p_f \cdot s_{p,f}}{\eta_{p,e}} \tag{5}$$

Assuming that variable power plant costs are solely determined by their fuel costs, and that all generators can exercise market power, the bidding strategy (cf. (1)) for all agents is defined as:

$$p_{c,s,p,t} = c_{p,fuel} * m_g \tag{6}$$

We assume the price mark-up to be 10% for all generators, following the example of [5].

3.4. Generation Capacity Investment

Investment decisions by generators are made sequentially in several rounds, and the decisions of each agent consequently influence the decisions of the following agents. The investment process is stopped as soon as no agent is willing to invest any more. To prevent a continuous bias towards single investors, the order in which agents invest is determined randomly in each year. Agents are assumed to finance 30% of the investment cost of a power plant from their cash flow (expecting a 12% return on equity), and pay this amount as down payments in equal instalments during the construction period of the plant. The remaining 70% are assumed to be debt-financed at an interest rate of 9%. The loan is assumed to be payed back in equal annuities during the depreciation period of the power plant (cf. Table 2). In the following the steps taken by the agents in each round are described:

1) Assume future fuel prices to correspond to the most recent price, and CO2 prices to correspond to the average of the last three years. In the current iteration of the model, agents have perfect foresight regarding demand growth.

2) Based on the above assumptions, as well as assuming typical lifetimes of the existing power plants, a bottom up estimation of future electricity prices $\hat{\rho}_{c,s,t}$ in each segment is made, using the merit order order of existing, and announced new power plants.

3) For each power generation technology, necessary investment conditions, such as sufficient cash reserves are asserted.

4) The expected running hours $\hat{r}_{s,p,t}$ are calculated from the estimated future energy prices in the segments, and compared to the minimum running hours of the technology (Table 2). Based on the expected running hours and prices, the expected operating cash flow CF_{Op} is calculated for a reference year t (uniformly 7 years ahead for all agents and technologies):

$$CF_{Op,p,t} = \sum_s \left((\hat{\rho}_{c,s,t} - \hat{c}_{v,p,t}) \cdot \hat{r}_{s,p,t} \cdot a_{p,s} \right) - c_{f,p,t} \tag{7}$$

In order compare power plants of different capacities κ_p with each other, the specific project net present value (NPV) of the considered power plant is calculated using the weighted average cost of capital (WACC) as the interest rate:

$$\mathrm{NPV}_p = \Big(\sum_{t=0 \ldots t_b} \frac{-I_p}{(1+\mathrm{WACC})^t} + \sum_{t=t_b+1 \ldots t_b+t_D} \frac{CF_{Op}}{(1+\mathrm{WACC})^t} \Big) / \kappa_p \tag{8}$$

Generation technology	Capacity κ_p [MW]	Construction time t_b [a]	Permit time t_{Pe} [a]	Technical lifetime [a]	Depreciation time t_D [a]	CO_2 capture eff. [%]	Min. Running hours r_h [h]	Base Availability $a_{20,p}$	Peak Availability $a_{1,p}$	Fuels (max. %)
Nuclear	1000	7	2	40	25	n.a.	5000	1	1	Uranium
Coal Pulverized SC	758	4	1	40	20	0	5000	1	1	Coal, Biomass (10%)
CPSC with CCS	600	4	1	40	20	85	5000	1	1	Coal, Biomass (10%)
IGCC	758	7	1	40	20	0	0	1	1	Coal, Biomass (10%)
IGCC with CSS	600	7	1	40	20	85	0	1	1	Coal, Biomass (10%)
Biomass Combustion	500	3	1	30	15	0	5000	1	1	Biomass
CCGT	776	2	1	30	15	0	0	1	1	Gas
CCGT with CCS	600	2	1	30	15	85	0	1	1	Gas
OCGT	150	2	1	30	15	0	0	1	1	Gas
Wind	150	2	1	25	15	n.a.	0	0.40	0.05	n.a.
Wind Offshore	150	2	1	25	15	n.a.	0	0.65	0.08	n.a.
Photovoltaic	100	2	1	25	15	n.a.	0	0.08	0.16	n.a.

Table 2: Power generation technology assumptions

5) If positive NPVs exist,the power plant p with the highest specific NPV_p per megawatt is chosen for investment.

3.5. Fuel Price and Demand Trends

Fuel prices and demand trends are modelled as stochastic trends, using a triangular distribution to determine the year-on-year growth rate. The assumptions for the average growth rate, as well as upper and lower bounds of the triangular function are summarised in Table 3. The fossil fuel average trends have been taken from [13], and include shipping costs for northern-central Europe. The costs for biomass are in the range estimated by [6] for northern European biomass.

Type	Unit	Demand	Coal	Gas	Biomass	Uranium
Start	€/GJ	s.b.	3.60	9.02	4.5	1.29
Average	[%]	2.00	1.07	1.47	1.00	1.00
Upper	[%]	5.00	5.07	8.47	5.00	2.00
Lower	[%]	-1.00	-2.93	5.53	-3.00	0.00

Table 3: Fuel price and demand growth rate assumptions

The load duration curves are taken from Germany (Country B) and the Netherlands (Country A), taking the starting year of 2010. It is assumed, that demand growth is equal in all segments of the load duration curve.

3.6. Initial Generation Mix

The two zones have distinctive initial generation mixes (cf. Table 4 only generation technologies with percentages greater than zero are given).

Technology	Country A [%]	Country B [%]
Coal Pulverized SC	33	45
CCGT	40	15
OCGT	16	5
Biomass	1	5
Nuclear	3	20
Wind	7	10

Table 4: Initial generation mix

4. Findings

The findings presented in this section are of preliminary nature and only a short overview of some of the first model results and analysis results are given. Since they only consider a single CO_2 price floor path, and do not include a sensitivity analyses of this decisive parameter, they are only indicative of a more thorough analysis. Four scenarios have been investigated, with each scenario containing 75 individual runs.

- No minimum CO_2 price.
- Price floor in country A, the smaller country.
- Price floor in country B, the larger country.
- Common price floor in both countries.

In the cases where a price floor applies, the starting price is 20 EUR/ton CO_2 and increases by 1 EUR/ton each year. The CO_2 cap has been set slightly above emissions, in order to reflect current low CO_2 prices. The cap is reduced linearly, so that after 50 years about 87% emission reductions would be achieved.

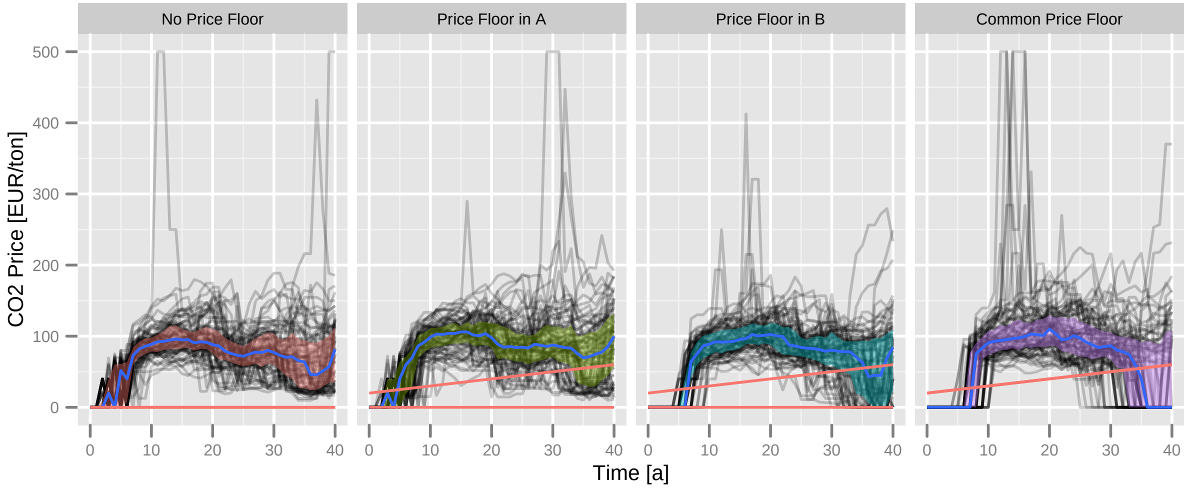

Figure 2: CO2 market prices of Monte-Carlo Simulation with median as well as upper and lower Quartiles. The red lines indicate the price floors.

4.1. *Effect on CO_2 prices*

Introducing (national) CO_2 price floors has a noticeable impact on CO_2 prices, as can be seen in Figure 2. First, a higher probability of very low CO_2 prices can be observed in the initial years if the described CO_2 price floors are applied. Since no capacity differences exist at this point, this effect is due to fuel switching measures. Therefore this period is longer in case of the larger electricity market B, and largest if a common CO_2 price floor exists. In the case of the introduction of the price floor in country B, and even more so if there is a common price floor, the minimum price comes into application frequently in the later years of the simulation period. In the case of the national price floor this leads to a higher probability of very low prices for the none-introducing country.

In a next step we calculate the standard deviations of the CO_2 prices as seen in the respective country as a first measure for price spread and volatility. The boxplot of the individual runs' standard deviations are shown in Figure 3. The introduction of a national CO_2 price floor leads to a decrease of CO_2 price variance in the introducing country; however, the none-introducing country sees an increase in CO_2 price variance. If both countries introduce a common price floor the overall price variance is reduced.

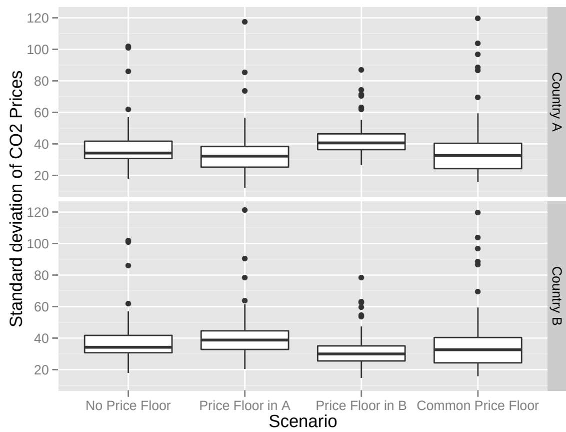

Figure 3: Standard deviation of individual runs' CO2 prices

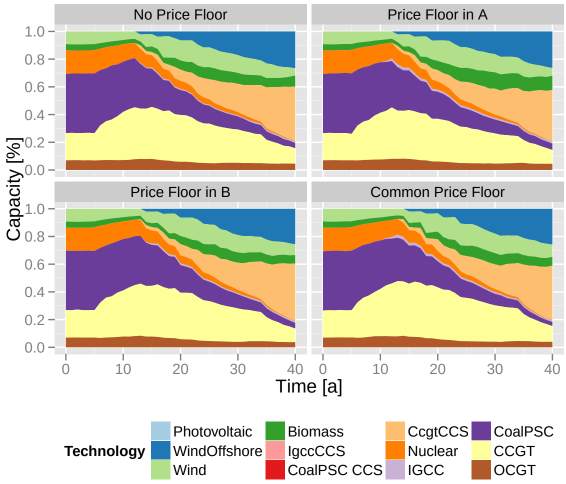

Figure 4: Capacity mix (Median capacities per technology, year and scenario)

4.2. Effect on Capacity Development

As the CO_2 price in the model is both a result of the current generation capacities, as well as an input for capacity investment decisions, the observable differences in CO_2 price should be reflected in and explained by the generation capacity pathway.

Figure 4 gives a broad overview of the median capacity development over time of the model, while Figure 5 shows better how much variance is contained in the Monte-Carlo simulation. All scenarios show first a shift from coal to gas and than an expansion of renewable energy sources (with earlier wind investments, which are later supplemented and finally substituted by offshore wind. Biomass and CCGT with CCS show the largest uncertainty about their total amount installed (cf. Figure 5), due to their substitutable role as dispatchable, low-carbon energy sources and their fuel price dependency. Coal and nuclear power are continuously being reduced, with only a low share of capacity being replaced over time.

To investigate what causes the different dynamics of the scenarios, the case of the price floor introduction in Country B is analysed in more detail. Figure 6 shows the difference between the median generation capacity development in the cases "Price Floor in B" and "No Price Floor"; however it should be noted that the overall differences are relatively low. A positive number in one year describes the additional capacity in the price floor B case, as compared to the case with no price floor. In order to

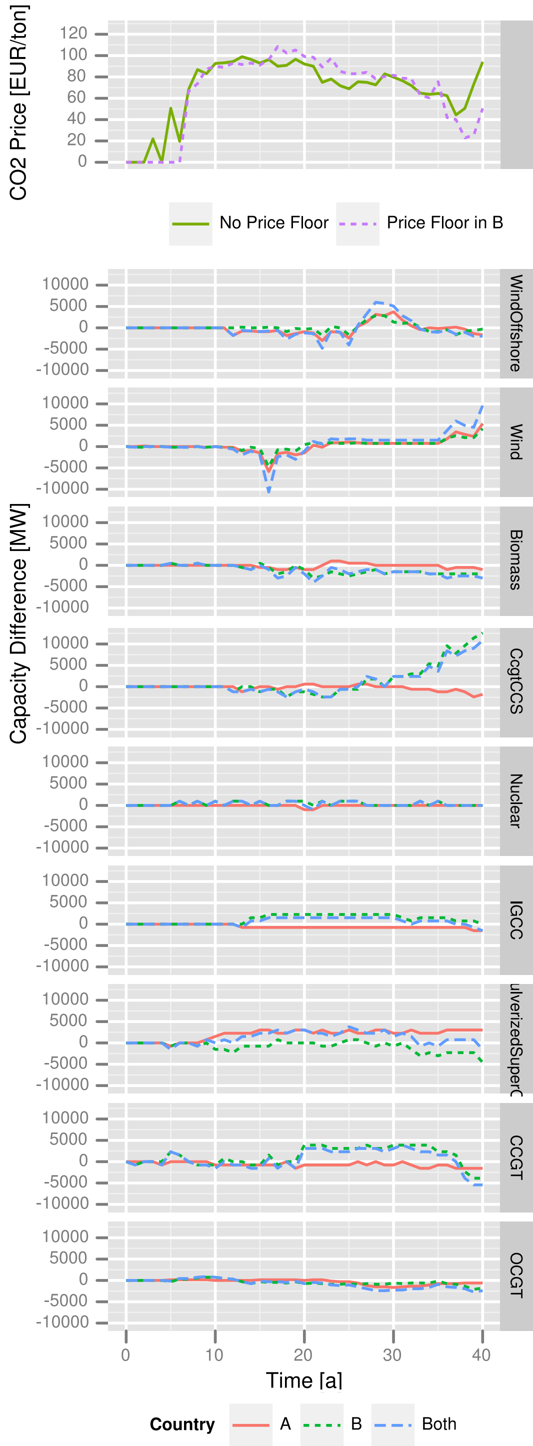

Figure 6: Difference between the technology capacity median of the "No Price Floor" and the "Price floor in B" cases, differentiated by country

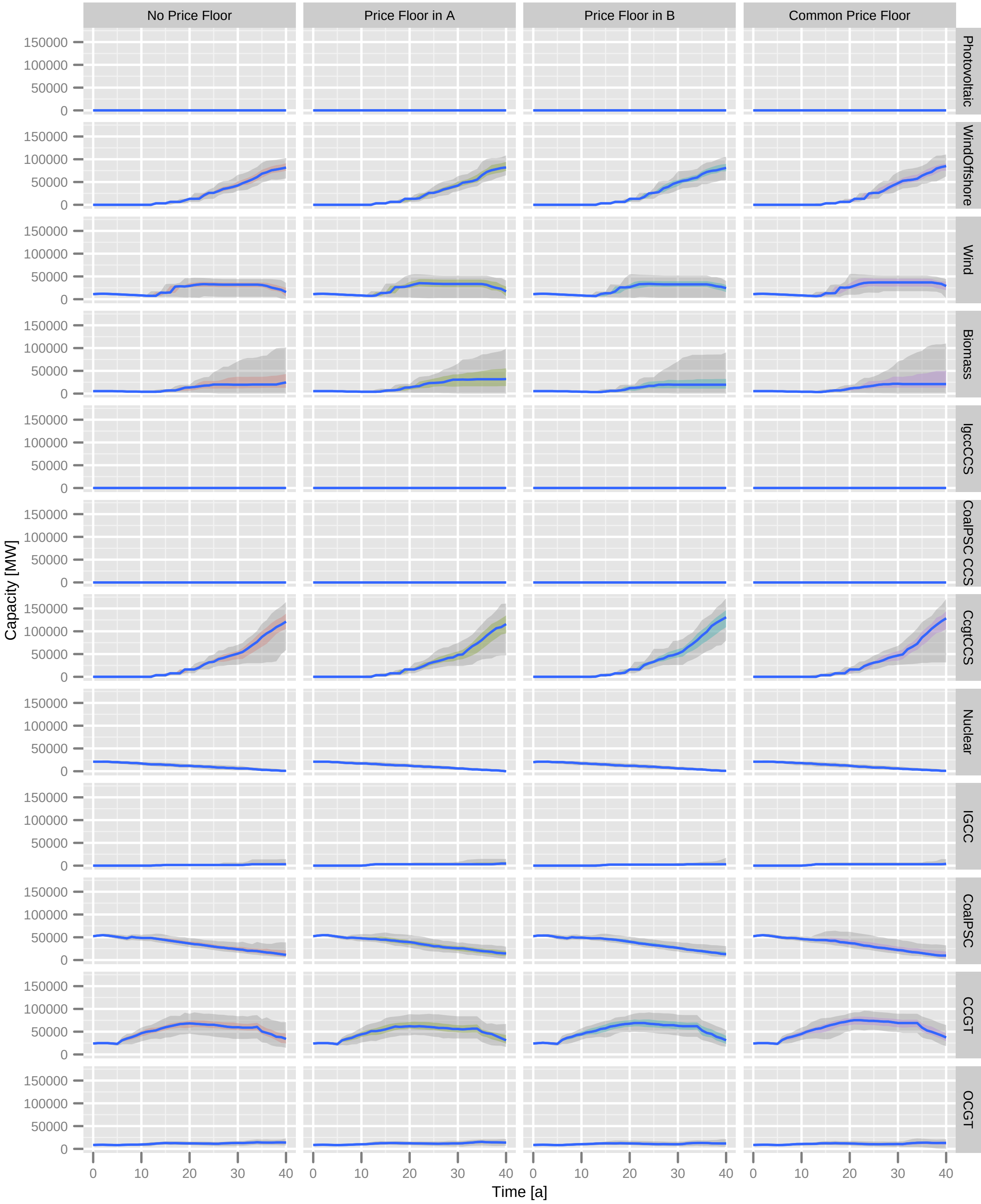

Figure 5: Median generation capacities with quartiles (coloured), and quantiles (covering 95%)

be able to relate it to the relevant CO_2 prices, the CO_2 price plot is included in the same figure. While the effect of the generation mix on the CO_2 price is direct, and due to the model structure only dependent on the current time step, the reverse effect is delayed. Thus when we analyse the effect the CO_2 price has on generation investment decision, we must first take the moving 3-year average that the agents use as a historic CO_2 price forecast into account, and finally include the different building and permit times of the power plant types.

Since initially no differences in generation capacity exist in the different scenarios, the prolonged initial period of low prices is caused solely by operational decisions. That means that the minimum price floor in country B leads to a different merit order and fuel switching to biomass, thus keeping CO_2 emissions below the cap. In the other case is fuel switching is only applied later, once a high enough CO_2 price exists.

By the years 13-15 the first differences in the generation capacity mix and the resulting CO_2 price become clearly visible, which are caused by the CO_2 price differences up to year 6: for both countries a small delay of wind investments compared to the no price floor case can be observed . In Country A which sees a prolonged period of no CO_2 prices in the first years, a relative surplus of pulverised coal power plants is build up, which due to the long power plant life times persist until the end of the simulation, while less IGCC is installed in the beginning period. In Country B on the other hand relatively more IGCC plants are build. These are also coal power plants, but have, due to their higher thermal efficiency, relatively lower CO_2 emissions.

These initial investment differences remain as structural differences throughout the rest of the simulation period and create a path dependency, which cannot not be reliably analysed down to technology level with a simple median capacity examination. They lead however, to a relative medium term CO_2 price increase and a later relatively stronger investment in carbon-low generation technologies such as CCGT with CCS.

5. Conclusion and Reflection

We presented a new long-term focused agent-based model to investigate the introduction of CO_2 price floors, in the form of a complimentary tax, in a two-country electricity market model. Four cases were investigated: No CO_2 price floor as a reference case, a single national CO_2 price floor in each of the two countries, and a common CO_2 price floor for both countries.

For the unilaterally introduced national price floors we found the size of the effects on the carbon market to depend on the introducing country; we found the larger country to stronger influence the common CO_2 market. Both countries were able to reduce CO_2 price variance by introducing a national CO_2 price floor; however, this lead to an increase of price variance for the non-introducing country. If both countries introduced a common CO_2 price floor overall price variance was decreased. In later years the price floor in the larger country, as well as in the common case, lead to an increased probability of an abatement overshoot (as compared to the CO_2 cap).

Looking at the development of the generation capacity over time in the scenario of the national CO_2 price floor being introduced by the larger country, we encountered path dependency effects and feedback loops between the CO_2 price and capacity development. In the early years lower CO_2 prices led to a delay in carbon-low investments and a structural persistent pulverised coal investment in the non-introducing country. These later led to slightly higher CO_2 prices in the medium run, and finally an abatement overshoot in the long-term.

However both the model and the evaluation and analyses need to be improved: The investment algorithm is a simple NPV calculation for a single reference year and does not consider price or other risks. CO_2 price and fuel price forecasting by the agents is based on historic averages and includes no extrapolation to the future (it should be noted however that current power investments do seem to be based on current CO_2 prices, instead of prices expected in the medium term). Many simulations parameters are not subject to uncertainty or a sensitivity analyses, such as the technical parameters of the generation technologies. The renewable representation is very simplified, and the CO_2 market contains no expectations about future prices, since it allows no multi-period banking of certificates. It may thus exaggerate CO_2 price movements.

The analyses presented in this paper was only a first step towards understanding possible dynamic investment effects in a two-country power system. Better analyses tools need to be applied and better indicators developed to investigate issues such as path dependency. Furthermore a sensitivity analysis of important model parameters (e.g. of price floor height and slope) is necessary to substantiate the results over a wider array of assumptions.

Our paper indicate possible dynamic long-term effects of CO_2 price floors, which static models do not consider. We also found that a national CO_2 price floor might lower CO_2 price variance in the introducing country, while increasing it in the overall market. However, both the model as well as the evaluation still need improvement to better substantiate this first hypotheses.

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