Universität für Bodenkultur Wien
Department für Wirtschafts- und
Sozialwissenschaften

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Sebastian Wehrle
Johannes Schmidt

Diskussionspapier
DP-64-2016
Institut für nachhaltige Wirtschaftsentwicklung

Juni 2016

University of Natural Resources and Life Sciences, Vienna
Department of Economic and Social Sciences

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Sebastian Wehrle*#, Johannes Schmidt*

** Institute for Sustainable Economic Development, University of Natural Resources and Life Sciences, Vienna*
 # Wien Energie GmbH

sebastian.wehrle@wienenergie.at

June 2016

Abstract

Low emission prices have stirred up discussion about political measures that aim to increase emission prices. District heating system operators, often municipal utilities, use a variety of heat generation technologies that are affected by the emission trading system. We examine whether district heating system owners have an incentive to support measures that increase emission prices in the short term. Therefore, we (i) develop a simplified analytical framework to analyse optimal decisions of a district heating operator, and (ii) investigate the market-wide effects of increasing emission prices, in particular the pass-through of emission prices to power prices. Using the clustered unit commitment model MEDEA of the common Austrian and German power system, we estimate a pass-through from emission prices to power prices between 1.1 and 0.75, depending on the absolute emission price level. Under reasonable assumptions regarding heat generation technologies, the pass-through from higher emission prices to power prices is about twice as high as required to make low-emission district heating system owners better off.

1 Introduction

With the signature of the Paris Agreement, the European Union (EU) committed itself to pursue climate policies to limit global warming to "well below 2°C" (United Nations Framework Convention on Climate Change, 2015), which implies the need for a drastic reduction in greenhouse gas (GHG) emissions. The EU's flagship instrument to reduce GHG emissions is the Emissions Trading System (ETS). Under the EU ETS, a cap is set on the maximum amount of GHG that can be emitted. A corresponding amount of emission allowances (EUA) is allocated and can be traded on exchanges ("cap-and-trade"). Currently approximately 43% of total greenhouse gas emissions in 30 countries are covered by the EU ETS (Brown, Hanafi, & Petsonk, 2012). In particular, the EU ETS covers carbon dioxide (CO_2) emissions from commercial airlines, a range of energy-intense industries and power generators.

Over the recent years, EUA prices declined from an average of 23.19 Euro per metric ton of CO_2 equivalent (€/t) in 2008 to an average of 7.71 €/t in 2015 (eex, 2016). In response to low emission prices, the EU decided to rein in emission allowance supply through "backloading" and the "market stability reserve". While both measures are directed at increasing prices, they are expected to be effective only after 2019.

Figure 1: EU Emission Allowance Price (Front Year)

Several EU member states aim at reducing GHG emissions significantly. Germany, for example, seeks to cut GHG emissions by 80% to 95% below 1990 levels by 2050 (Bundesministerium für Wirtschaft und Technologie, 2010). However, the incentives for emission reduction provided by current emission prices are considered insufficient to reach ambitious long-term GHG reduction goals by the German government (Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit, 2014). In consequence, further measures to support further GHG emission reductions are considered. Which measures ultimately become implemented also depends on stakeholders' backing.

In the following, we examine whether district heating system owners, mostly municipal utilities, have an incentive to support measures that increase emission prices in the short term. Jouvet & Solier (2013) show that power generators with low or no carbon dioxide emissions can benefit from rents that are created by the pass-through of emission prices to power prices. Therefore, we (i) develop a simplified analytical framework to analyse decisions of a district heating operator, and (ii) investigate the market-wide effects of increasing EUA prices, in particular the pass-through of EUA prices to power prices.

Methodologically, we rely on a technically explicit power system model to analyse price effects in various scenarios for emission prices and the power plant stock. This allows us to quantify the pass-through at varying levels of emission prices.

In contrast, the literature on the pass-through from emission prices to power prices is dominated by econometric analysis (Sijm, Neuhoff, & Chen, 2006; Zachmann & von Hirschhausen, 2008; Hintermann, 2014; Fabra & Reguant, 2014) of pass-through at actual historical emission prices.

For example, Fabra & Reguant (2014) conduct an econometric analysis of the pass-through from emission prices to power prices. A rich data set available for the Spanish power market allows estimating the impact of changes in hourly marginal cost on emission prices. The authors find an average pass-through rate between 0.77 and 0.86 in the Spanish market over the course of January 2004 to February 2006. The measured pass-through is explained by (i) weak incentives for markup adjustment, which is in turn explained by the high correlation of cost shocks among firms and by the limited demand elasticity, and (ii) the absence of relevant price rigidities.

However, Hintermann (2014) argues that econometric analyses based on price or price spread regressions produce biased pass-through estimates, amongst others due to the merit order being correlated with input prices. To improve on price regressions, Hintermann constructs estimates of hourly marginal cost from detailed power sector data. Using this dataset he finds pass-through rates between 0.98 and 1.06 for the German market from January 2010 through November 2013.

Our approach therefore complements econometric analysis and goes beyond the approach of Hintermann, as we take into account full (inter-temporal) optimization of the power system, instead of relying on hourly models of the merit order only.

2 Effect of emission prices on suppliers of district heating – a stylized model

District heating is typically supplied by a broad portfolio of heat generation technologies. Some of these technologies, for example heat boilers, are generating heat only, while others, such as CHP-plants, generate heat and power jointly. A profit-maximizing operator will dispatch heat generation units according to their marginal cost, with the lowest cost unit being dispatched first. For co-generation units, marginal cost is affect by the prevailing electricity price and the emission price.

To analyse the effect of emission allowance prices on the profitability of district heating suppliers, a simplified portfolio consisting of co-generation units C, that generate power and heat at the same time, and natural gas boilers B, that generate heat only, is considered.

Under the assumptions of perfect competition, the profit function of each technology is given by

$$\Pi^B = p_{th}q_{th} - p_f q_f - p_e q_e$$

$$\Pi^C = p_{el}q_{el} + p_{th}q_{th} - p_f q_f - p_e q_e$$

where p denotes prices and q quantities of electricity el, heat th, fuel f (coal or natural gas), and emissions e. The profit functions can be re-written such that all quantities are expressed in terms of fuel usage.

$$\Pi^B = p_{th}\eta_{th}q_f - p_f q_f - p_e em_f q_f \tag{1}$$

$$\Pi^C = p_{el}\eta_{el}q_f + p_{th}\eta_{th}q_f - p_f q_f - p_e em_f q_f \qquad (2)$$

where η is the efficiency (measured as MWh of output per MWh of input) and em is the fuel emission factor in tons of CO_2 emitted per MWh of fuel used.

The first-order conditions of profit maximization for a heat boiler (1) and a CHP-plant (2) can be rearranged to express heat prices p_{th}

$$p_{th}^B = \frac{1}{\eta_{th}^B} p_f + \frac{em_f}{\eta_{th}^B} p_e \qquad (3)$$

$$p_{th}^C = \frac{1}{\eta_{th}^C} p_f + \frac{em_f}{\eta_{th}^C} p_e - \frac{\eta_{el}^C}{\eta_{th}^C} p_{el} \qquad (4)$$

From the perspective of the district heating system owner, these heat prices reflect the cost of heat generation. The effect of emission prices on the cost of heat generated by CHP units can be determined by taking the derivative of equation (4) with respect to p_e, keeping in mind that the electricity price depends, amongst others, on the emission price $p_{el}(p_e,\cdot)$.

$$\frac{\partial p_{th}^C}{\partial p_e} = \frac{em_f}{\eta_{th}^C} - \frac{\eta_{el}^C}{\eta_{th}^C} \frac{\partial p_{el}}{\partial p_e}$$

The co-generation heat cost will decline, if the emissions per-unit of heat are smaller than the efficiency-weighted pass-through rate $\partial p_{el}/\partial p_e$. Obviously, co-generation units with a lower emission factor em_f are the first to benefit from rising emission prices. In particular, the heat cost of coal-fired CHP-units ($em_{f1} = 0.333$) with electrical efficiency below 30% will decline in emission prices only if the pass-through rate is above a high 1.11. In contrast, heat cost from natural gas-fired CHP-plants ($em_f = 0.2$) with the same efficiencies will decline at pass-through rates above 0.67. Highly efficient natural gas-fired CHP-plants with an electrical efficiency of 50% can benefit from rising emission prices already at pass-through rates above 0.4.

As boilers do not generate revenues from electricity generation, their heat cost is strictly increasing in emission prices. Taking the derivate of equation (3) with respect to p_e gives $\partial p_{th}^B/\partial p_e = em_f/\eta_{th}^B$. Given the thermal efficiency of a natural gas-fired heat boiler is around 90%, this results in a cost increase of 0.222 €/MWh for each 1 €/t increase in the emission price.

Changes in heat cost can affect dispatch of heat generation plants. Under the assumptions that a) some heat demand has to be met either by CHP units or by heat boilers, and b) neither heat boilers nor CHP units are capacity constrained, a cost minimizing operator will prefer to dispatch co-generation units if their heat cost p_{th}^C is below the boilers' heat cost p_{th}^B. Assuming that the co-generation unit uses fuel f_1 and heat boilers use fuel f_2, the arising inequality $p_{th}^C \leq p_{th}^B$ can be simplified to

$$p_{el} \geq \left(\frac{1}{\eta_{el}^C}\right)\left(p_{f_1} + em_{f_1}p_e - \frac{\eta_{th}^C}{\eta_{th}^B}(p_{f_2} + em_{f_2}p_e)\right) \qquad (5)$$

The impact of a change in the emission allowance price on plant dispatch can be determined by taking the derivative of equation (5) with respect to the emission allowance price p_e.

$$\frac{\partial p_{el}}{\partial p_e} \geq \frac{1}{\eta_{el}^C}\left(em_{f_1} - \frac{\eta_{th}^C}{\eta_{th}^B} em_{f_2}\right) \qquad (6)$$

Equation (6) implies that the system operator has an incentive to dispatch co-generation units preferentially if the pass-through from emission prices to power prices is larger than the change in the cost of emissions from fuel combustion. While the pass-through depends on the wider power system, emissions from fuel combustion depend only on the specific technical characteristics (efficiencies, type of fuel used) of the district heating system.

If the share of boilers in total emission intense heat generation is large, the district heating system operator might find itself in a situation where total cost of heat generation increase in response to rising emission prices in spite of (marginal) reductions in the heat generation cost of CHP-units. The total profit from heat generation will increase, if the additional (net) revenues of CHP-units exceed the additional cost of heat boilers, i.e. if

$$-\frac{\partial p_{th}^{C}}{\partial p_e} q^C > \frac{\partial p_{th}^{B}}{\partial p_e} q^B \tag{7}$$

Using the identity $q^B = q^T - q^C$ with q^T being total heat production from emission intense generators, and assuming both units are fired by natural gas (i.e. $em_{f_1} = em_{f_2}$) equation (7) can be rearranged to yield

$$q^C > \frac{\eta_{th}^{C}\, em_f}{\eta_{el}^{C}\, \eta_{th}^{B}\, {}^{\partial p_{el}}/_{\partial p_e} + \eta_{th}^{C}\, em_f - \eta_{th}^{B}\, em_f} q^T$$

For illustration, assume that the electrical and thermal efficiencies of a natural gas-fired combined-cycle CHP-plant stand at 45% and 40%, respectively. Then, total profits from heating generation increase if more than 39.3% of the emission intense heat is produced in CHP-plants even if the pass-through rate is as low as 0.75. If CHP-generation is sufficiently high, the district heating system operator can increase profits if the pass-through rate remains above 0.444. Below this pass-through level, profits decline as emission prices rise.

In the following, we use the power system model MEDEA to investigate the effect of emission prices on power prices. Power plant dispatch and resulting power prices are derived for emission prices in the range of 7.71 €/t (which is equal to the average EUA price in 2015) to 72.71 €/t given the current inventory of power plants.[1] The results are used to approximate $\partial p_{el}/\partial p_e \cong \Delta p_{el}/\Delta p_e$, the pass-through from emission prices to power prices.

3 Data and Methods

3.1 General description of the power system model MEDEA

MEDEA is a clustered unit commitment model similar to Palmintier (2013) of the power system in the common bidding zone in Austria and Germany. Total system costs of meeting price inelastic (residual) electricity and heat demand are minimized through the hourly dispatch of installed thermal and hydro storage power plants, taking power generation from intermittent sources of renewable energy (wind and solar radiation) as given. The model uses a mixed-integer linear (MIP) approach to account for inflexibilities in thermal power generation[2].

Within the common bidding area of Austria and Germany, 893 conventional power plants are included. Each conventional plants belongs to one of 29 power plant clusters, which are differentiated by fuel (uranium, lignite, hard coal, natural gas, mineral oil, biomass, water) and generation technologies (steam turbine, combustion turbine, combined cycle, etc.). Technical parameters of power plant operation are represented in detail. Start-up of a plant requires

[1] Extending the analysis to future generation portfolios is left for further research.
[2] We acknowledge that the marginals on the balancing equation in a MIP may not be considered to be market prices, as those prices are not necessarily market clearing (Huppmann & Siddiqui, 2016). In further research we will investigate whether marginals from our particular analysis are market clearing.

additional fuel. Once a plant has started up, its generation can be adjusted flexibly between the plant's rated capacity and its minimal generation. Shutting down a power plant again requires additional fuel use (Morales-España, Latorre, & Ramos, 2013). Power plant efficiencies are estimated based on the plant's age and technology (Egerer, et al., 2014). Co-generation of heat and power is possible in CHP-plants, which can adjust power and heat generation flexibly within a given, three-dimensional feasible operating region. To provide additional operational flexibility for CHP-plants, heat demand can alternatively be met by heat-only natural gas boilers. In addition to thermal plants, electricity can also be generated by the 45 pumped hydro storage plants and seasonal hydro storage plants with a total capacity of 10.4 GW included in the model.

To reduce computation times, the model is solved iteratively for blocks of 1167 hours. To avoid last-round effects, the last 72 hours of each iteration are discarded. The solution for the 1095th hour is then used as starting values for the subsequent iteration. We also solve a linear (LP) version of the model (see appendix A for details). The model is written in GAMS and solved by CPLEX (12.6.1.0). A detailed formal description of the model is provided in appendix A.

3.2 Data

3.2.1 Power and heat demand

The residual electricity demand that is faced by conventional power plants is typically approximated by subtracting electricity generation from renewable sources and net imports of electricity from total load. As this leads to several problems regarding data quality (Schuhmacher & Hirth, 2015), we are instead using actual data regarding the "actual generation of power plants" with a rated capacity above 10 MW (eex, 2016). While this is a good representation of the actual residual demand faced by conventional generators, it also implies that exports and imports of electricity remain constant across emission price scenarios.

Hourly district heating demand was estimated based on synthetic load profiles for natural gas (Almbauer & Eichsleder, 2009). Heat demand depends on average daily temperatures (EUMETSAT CM SAF, 2016) and is scaled to total final consumption of district heat in Germany and Austria (AG Energiebilanzen e.V., 2015; Statistik Austria, 2016).

Descriptive statistics for power and heat demand in the year 2015 are provided in Table 1.

Table 1: Descriptive Statistics of Power and Heat Demand

	Unit	Min	Max	Mean	Std Dev	Source
Residual power demand	GWh/h	20.091	68.284	43.603	9.661	eex transparency
District heating demand	GWh/h	4.707	46.259	16.443	9.422	Own calculations

3.2.2 Conventional power plants

Information regarding power plant capacities (electrical, thermal), efficiencies and locations of German power plants are taken from the open power system data project (Open Power System Data, 2016). Data for power plants in Austria is based on Platts' Power Vision, a commercial power plant database (Platts, 2014) that we extended through own research. In total, our database contains 1326 thermal and hydro power plants with an electrical capacity of 112.7 GW. Further technical characteristics such as minimum up and down times follow Schröder et. al. (2013).

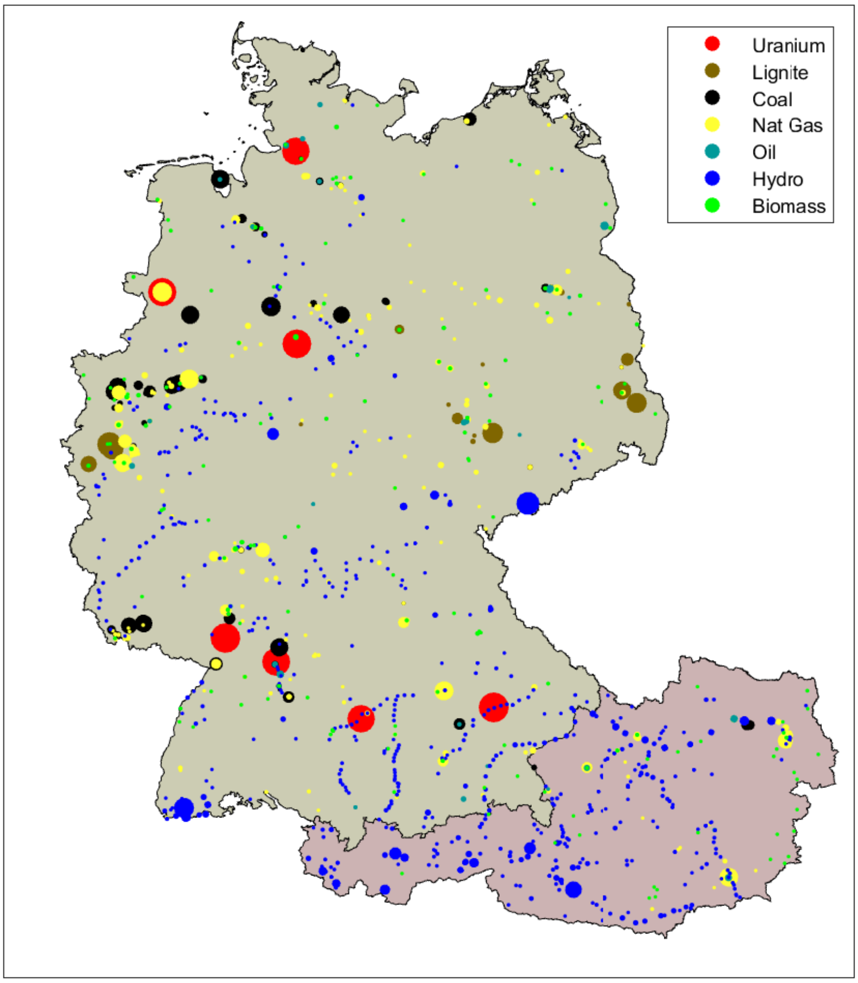

Figure 2: Thermal and hydro power plants in Germany and Austria
(Dot size proportional to power plant capacity)

3.2.3 Water reservoirs and pumped storage plants

For Austria, inflows of water to reservoirs are approximated by combining data on daily water runoff (Bundesministerium für Land- und Forstwirtschaft, 2016) with monthly data on water reservoir levels provided by the regulatory body (E-Control, 2015). For Germany, inflows are approximated based on the "aggregate filling rate of water reservoirs and hydro storage plants" and the "actual generation of hydro pumped storage and hydro water reservoir plants" published by ENTSO-E (2016).

3.2.4 Prices

Realized prices of hard coal, natural gas and EU emission allowances for the year 2015 are taken from the European Energy Exchange (eex, 2016). Prices for mineral oil are approximated on the basis of prices for Brent crude (EIA). Descriptive Statistics of all price time series are displayed in Table 2.

As there are no market prices for nuclear fuel and lignite, we estimate lignite cost at 3.80 €/MWh_{th} (excluding emission cost) and 6.50 €/MWh_{th} for nuclear fuel (including Germany's nuclear fuel tax). Prices for solid biomass are estimated at 24.00 €/MWh. Power generated from biomass-fired plants is assumed to receive a feed-in remuneration of 84 €/MWh. In consequence, biomass-fired plants are running at full capacity.

Table 2: Descriptive Statistics of Energy and Emission Prices

Fuel	Unit	Year	Min	Max	Mean	Std Dev
Coal (API2)	€/MWh_{th}	2015	5.99	8.23	7.21	0.566
Natural Gas (NCG)	€/MWh_{th}	2015	14.72	24.39	19.90	1.788
Mineral Oil	€/MWh_{th}	2015	18.94	34.77	27.75	4.211
EU Emission Allowance	€/t CO_2	2015	6.44	8.68	7.71	0.563

4 Results: System-wide effects of increasing emission prices

To approximate pass-through rates from emission prices to power prices, we determine power plant dispatch in 14 emission price scenarios s. Starting with the actual annual average price of EUAs in 2015 (7.71 €/t), we increase emission prices in steps of 5 €/t up to an annual average emission price of 72.71 €/t. The electricity base price (i.e. the annual average of the hourly spot price) is then used to approximate the pass-through by

$$\frac{\Delta\, p_{el}}{\Delta p_e} = \frac{p_{el}^{s} - p_{el}^{s-1}}{p_e^{s} - p_e^{s-1}} \qquad (8)$$

The resulting pass-through estimates are presented in Figure 3 for the MIP formulation of MEDEA, which represents plant flexibility in detail and for the LP formulation of MEDEA. Details on the model formulations are provided in Appendix A.

Irrespective of the chosen modelling approach, we see pass-through decline from around 1.1 at emission prices around 10 €/t to approximately 0.78 at emission prices near 55 €/t (c.f. Figure 3). This can be explained by (i) a "fuel switch" triggered by rising emissions prices, (ii) a changing pattern of co-generation outputs and (iii) an increase in the overall efficiency. Moreover, a change in operational patterns brought upon by rising emission prices explains the variation of MIP-based pass-through estimates around the LP-estimates of pass-through.

The "fuel switch" in response to increasing emission prices is illustrated in Figure 4 (Total Fuel Combustion). At low emission prices, lignite and coal fired power plants dominate the generation mix. Approximately 415 TWh of lignite and 360 TWh of hard coal are burned per year, accounting for 70.8% of total fuel use. Not surprisingly, carbon dioxide emissions from power generation are high, particularly due to the high emission intensity of lignite (around 0.45 t of CO_2 are emitted per MWh_{th} of lignite burned) and the low overall efficiency of the lignite-fired power plant fleet.

As emission prices rise, generation costs of the least efficient lignite-fuelled power plants increase strongly. At low emission price increases, the most inefficient lignite-fired power plants become replaced by generation from not fully or not yet utilized coal-fired power plants. With moderate increases in emission prices, more and more lignite-fired power plants become replaced by coal-fired and also highly efficient natural gas-fired power plants. Up to an emission price level of about 32 €/t, power and heat generation from natural gas-fuelled CHP plants is strictly increasing. Except for the CHP plants with the highest electrical efficiency, heat generation outweighs electricity generation. Overall, carbon dioxide emissions decline strongly, as can be seen in Figure 4. Along with emissions, the pass-through rate declines strongly, while overall system efficiency increases (i.e. the amount of fuel required to meet final energy demand declines).

At emission price levels above 32 €/t, substitution of emission intense generation with low-emission generation continues. Combined-cycle CHP plants are increasingly generating power instead of heat to substitute power generation from high-emission sources. Heat generation is shifted from combined-cycle power plants to less efficient power plants and heat boilers. Potential gains from increased dispatch of efficient low-emission plants with previously low utilization are largely realized. Higher emission prices lead to the dispatch of units that are either less efficient or use emission intense fuels. In consequence, emission reductions and the decline in the pass-through are not as pronounced as before. Overall efficiency improves, though not as much as before.

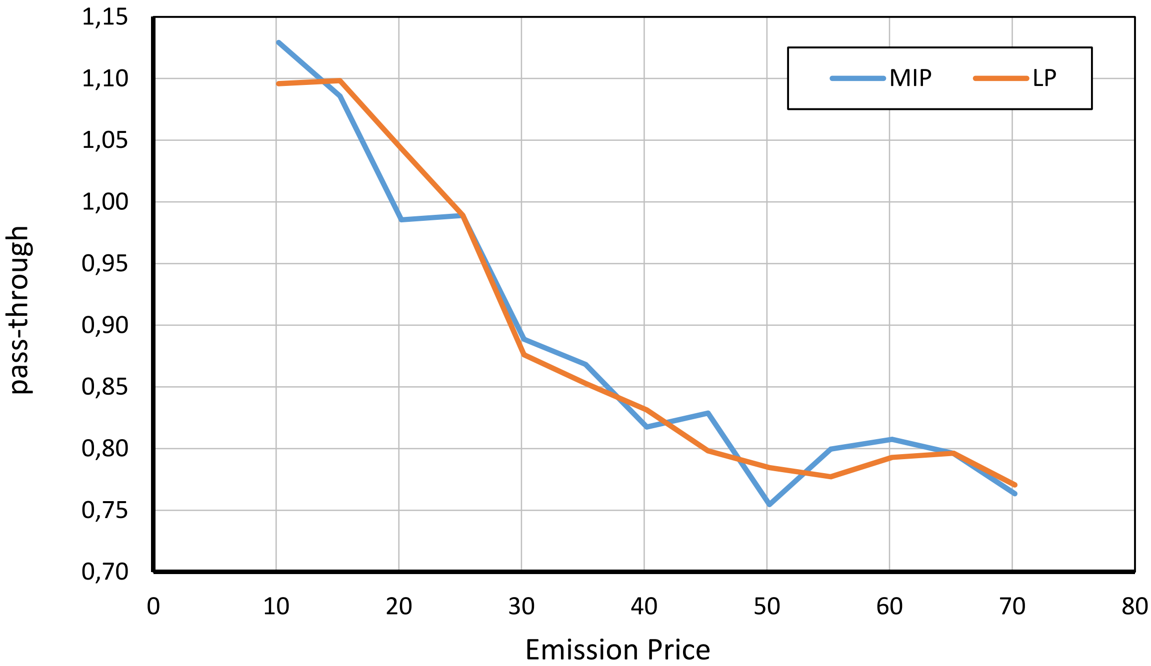

Figure 3: Pass-through from emission to power prices

As emission prices reach 55 €/t, power generation from lignite-fired units is close to its minimum, while heat generation by natural gas-fired steam and gas turbines is close to its maximum. The increasing heat production from less efficient natural gas-fired units substitutes for declining heat output from combined-cycle generators, where power generation begins to exceed heat generation. Any further increase in emission prices above 55 €/t leads to comparatively small changes in power plant dispatch, resulting in a relatively stable evolution of the pass-through rate.

Deviations of the pass-through rate estimated with the MIP formulation of MEDEA from the pass-through estimates of the LP formulation of the power system model are caused by changes in power plant operation. At low emission prices, power is generated predominantly in large lignite or coal-fired units. Due to their size, these units offer considerable ramping potential (i.e. to adjust generation up or down in response to fluctuations in residual demand). As lignite-fired units leave the market, the remaining units need to provide more flexibility through an increased number of starts and stops. As emission prices rise further, more lignite-fired power plants exit the market and are replaced by smaller natural-gas fuelled units. These smaller units can be started-up at lower cost than coal-fired units. Consequently, they provide the bulk of flexibility that is required to meet fluctuations in residual demand. As a result, the average number of start-ups of natural gas-fired power plants increases strongly at emission prices between 20 €/t and 30 €/t. Similarly, at emission prices around 50 €/t, small and flexible but comparatively inefficient natural gas turbines enter the market and provide additional flexibility through a large number of starts and stops.

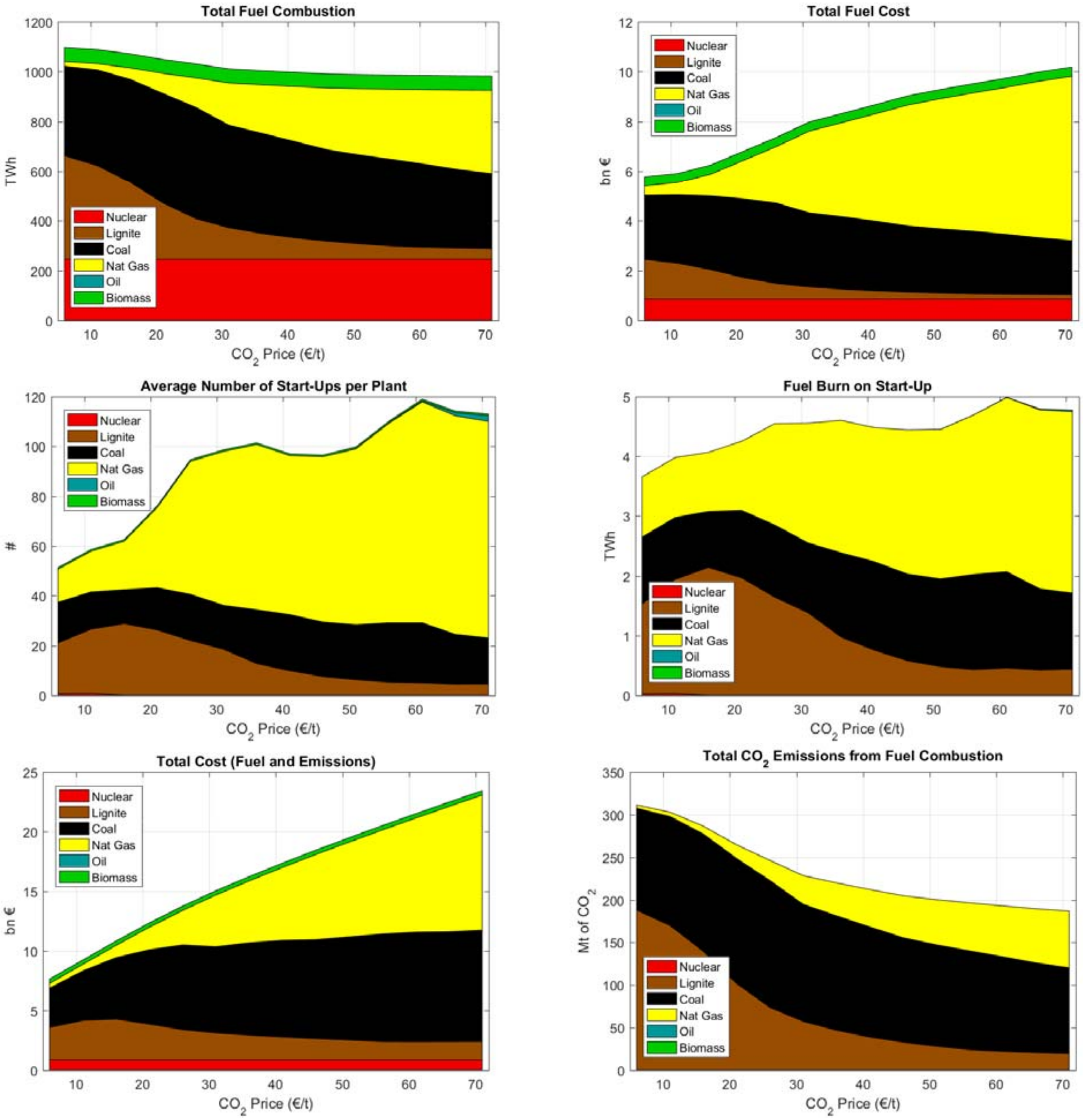

Figure 4: Results from Emission Price Scenarios

5 Discussion

Our results hinge on several simplifying assumptions. Pass-through rates were approximated with the power system model MEDEA, which assumes perfectly competitive markets and a completely price-inelastic demand. Moreover, MEDEA only represents the market in the Austro-German bidding zone and does not take potential changes in imports and exports, which can be brought upon by changing emission prices, into account. Finally, heat demand can be met by any heat generating unit in the common market area.

All of these factors can lead to an overestimation of pass-through rates. However, the German "Monopolkommission"[3] (2015) finds no significant evidence of excessive market power on the Austro-German power market. Also, the short-run price elasticity of electricity demand is found to be very low (Lijesen, 2007). Hence, we believe both factors are unlikely to lead to estimation bias that exceeds the difference between our lowest estimated pass-through rate (0.75) and the pass-through rate at which typical district heating system operators will certainly not benefit from increasing emission prices (0.444).

However, our electricity system model does currently not allow quantifying the effects of changes in emission prices on electricity imports and exports. Potentially, under high emission prices, a higher volume of imports from low-carbon sources (e.g. French nuclear power plants) could crowd out some of the emission intense production with high marginal cost. This would reduce pass-through rates. Moreover, we focused on the effect of immediate measures to raise emission prices. In the long run, higher emission prices will lead to adjustments in power plant investments. Together with the ongoing expansion of renewable energy generation capacities, this leads to less emission intense power generation and consequently lower pass-through rates.

Individual district heating areas could be modelled, but would require defining specific power plant clusters that can serve the corresponding heat demand. As a result, the number of clusters would increase considerable, leading to a significant increase in runtimes.

In future research we aim to analyse the long-run effects of emission price increases in the context of the European power generation system.

6 Conclusion

We have shown that the emission price has a large effect on the power price through the almost complete pass-through of marginal cost to power prices. Moreover, the rate of pass-through depends not only on the weak incentives for mark-up adjustment and the absence of relevant price rigidities (Fabra & Reguant, 2014), but also on the absolute level of the emission price.

Our estimated pass-through rates are almost twice as high as the pass-through rates required to make owners of district heating systems with low emission intensity better off. Thus, we conclude that district heating system owners that operate gas-fired assets should favour higher emission prices. Increased emission prices will induce higher utilization of gas-fired CHP-plants and raise profits provided that a sufficient share of total fossil heat generation is sourced from co-generation units.

As higher emission prices increase profits for district heating systems with low emission intensity (e.g. natural gas-fired assets only), owners of these systems have an incentive to support political measures that lead to increasing emission prices. Companies that hold power generation assets with low emission intensity could also benefit from rising emission prices.

However, the ongoing decarbonisation of the energy system is likely to reduce pass-through rates in the future, making it harder for low-emission generators to benefit from higher emission prices. Consequently, emission price increasing measures should be implemented rather sooner than later.

[3] The „Monopolkomission" advises the German government on competition policy and regulation. It regularly monitors the German power market.

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8 Appendix A

8.1 List of Variables and Parameters

8.1.1 Sets

$t \epsilon T$	time periods (hours)
$g \epsilon G$	clusters of generators
$CHP \epsilon G$	subset of clusters of combined heat and power generators
$PSP \epsilon G$	subset of (pumped) hydro storage plants
$f \epsilon F$	fuels
$s \epsilon S$	start-up intervals
$p \epsilon P$	products
$l \epsilon L$	limits to the operation area of CHP plants

8.1.2 Parameters

$P_{t,f}$	Price of fuel f at time t [€/MWh]
$P_{t,eua}$	Emission allowance price at time t [€/t]
em_f	emission factor of fuel f [t of CO_2 / MWh of fuel used]
$CSU_{g,f,s}$	use of fuel f of a generator in cluster g starting up from state s. [MWh]
$CSD_{g,f}$	use of fuel f of generator in cluster g on shut down [MWh]
$D_{t,p}$	Demand for product p at time t [MW]
$Q_{t,pv}$	solar energy generated at time t [MW]
$Q_{t,we}$	wind energy generated at time t [MW]
$Q_{t,ror}$	energy generated by run-of-river plants at time t [MW]
$\underline{C}_{g,p}$	minimum generation of product p by generator in cluster g [MW]
$\overline{C}_{g,p}$	maximum generation of product p by generator in cluster g [MW]
$SU_{g,p}$	maximum generation of product p at start-up of generator in cluster g [MW]
$SD_{g,p}$	maximum generation of product p at shut-down of generator in cluster g [MW]
TU_g	Minimum uptime of generator in cluster g
$TSU_{g,s}$	Times defining the start-up state (cool, warm, hot) of generator in cluster g [h]
$ORP_{g,l,p}$	output of product p at limit l of operating region of CHP plant in cluster g
$ORF_{g,l,f}$	use of fuel f at limit l of operating region of CHP plant in cluster g
$\eta_{g,f,p}$	efficiency of generator g using fuel f to generate product p
N_g	number of generators in cluster g

R_g ramping rate of generator in cluster g [MW]

$\overline{STOR}_g$ capacity of storage reservoirs of storage plant g

8.1.3 Variables

$qf_{t,g,f}$ quantity of fuel f used by generator g at time t

$sup_{t,g}$ integer variable equal to 1 if generator g starts up at time t, 0 otherwise

$sdn_{t,g}$ integer variable equal to 1 if generator g shuts down at time t, 0 otherwise

$qon_{t,g}$ integer variable equal to 1 if generator g is operational at time t, 0 otherwise

$qp_{t,g,p}$ energy generated by generator g at time t in excess of minimum generation level

$qpsp_{t,g}$ power generated by pumped storage plant g at time t

$ppsp_{t,g}$ power stored in pumped storage plant g at time t

$qconv_{t,g,l}$ convexity variable g

$\delta_{t,g,s}$ integer variable equal to 1 in the hour where the unit starts up and has been previously offline within $TSU_{p,s}$ $TSU_{p,s+1}$hours

$qstor_{t,g}$ quantity of energy stored in storage plant g at time t

A1 Mathematical description of the power system model MEDEA

MEDEA uses a MIP formulation of the unit commitment problem for thermal units within the Austro-German bidding zone. Operation of pumped storage plants is modelled linearly.

The model's objective is to minimize total system cost, the sum of production cost, start-up cost and shut-down cost

$$\min \left[\sum_{t,f} \left(P_{t,f} + em_f P_{t,eua} \right) \sum_g \left(qf_{t,g,f} + \sum_s CSU_{g,f,s}\, sup_{t,g} + CSD_{g,f} sdn_{t,g} \right) \right] \tag{9}$$

In each hour the market has to clear, such that electricity supply from thermal and (pumped) storage plants equals electricity demand less power generation from non-dispatchable sources (wind energy, photovoltaics, and run-of-river hydro plants).

$$\begin{aligned} &D_{t,pwr} - Q_{t,we} - Q_{t,pv} - Q_{t,ror} \\ &\quad = \sum_g \left(qon_{t,g}\, \underline{C}_{g,pwr} + qp_{t,g,pwr} \right) + \sum_{g \epsilon PSP} qpsp_{t,g} - \sum_{g \epsilon PSP} ppsp_{t,g} \ , \forall t \end{aligned} \tag{10}$$

Generation is modelled in two blocks. If operational, each unit generates at least its minimal output $\underline{C}_{g,p}$. In addition it can produce energy $qp_{t,g,p}$ up to its maximum generation.

In linear (economic dispatch) models, the marginals ("shadow prices") on equation (10) can be interpreted as power prices in an energy-only market.

Heat supply from CHP units and heat boilers must be adequate to meet district heating demand $D_{t,ht}$.

$$D_{t,ht} \leq \sum_{g \epsilon CHP} \left(qon_{t,g} \underline{C}_{g,ht} + qp_{t,g,ht} \right) \ , \forall t \tag{11}$$

Capacity constraints are enforced by the generation limits similar to (Morales-España, Latorre, & Ramos, 2013).

$$qp_{t,g,p} \leq (\overline{C}_{g,p} - \underline{C}_{g,p})qon_{t,g} - (\overline{C}_{g,p} - SU_{g,p})sup_{t,g}, \forall t, TU_g = 1 \quad (12)$$

$$qp_{t,g,p} \leq (\overline{C}_{g,p} - \underline{C}_{g,p})qon_{t,g} - (\overline{C}_{g,p} - SD_{g,p})sdn_{t+1,g}, \forall t, TU_g = 1 \quad (13)$$

For cases in which $TU_g > 1$, constraints (12) and (13) can be replaced by

$$\begin{aligned} qp_{t,g,p} \leq (\overline{C}_{g,p} - \underline{C}_{g,p})qon_{t,g} - (\overline{C}_{g,p} - SU_{g,p})sup_{t,g} \\ - (\overline{C}_{g,p} - SD_{g,p})sdn_{t+1,g}, \forall t, TU_g > 1 \end{aligned} \quad (14)$$

which is a tighter and more compact formulation of the capacity constraint.

Coproduction of heat and power in CHP-plants is governed by

$$\sum_l qconv_{t,g,l} = qon_{t,g} - sup_{t,g} - sdn_{t+1,g}, \forall g \in CHP \quad (15)$$

$$\begin{aligned} &\sum_l qconv_{t,g,l}\, ORP_{g,l,p} \\ &\quad = (\underline{C}_{g,p} qon_{t,g} + qp_{t,g,p}) - sup_{t,g} SU_{g,p} - sdn_{t+1,g} SD_{g,p}, \forall g \\ &\quad \in CHP \end{aligned} \quad (16)$$

$$\sum_l qconv_{t,g,l}\; ORF_{g,l,f} \;\leq\; qfuel_{t,g,f} \quad (17)$$

Power production by power-only generators is modelled as a linear function of plant efficiency

$$qon_{t,g}\, \underline{C}_{g,pwr} + qp_{t,g,pwr} \;\leq\; \sum_f \eta_{g,f,pwr}\, qf_{t,g,f}\,, \forall\, t, g \notin CHP \quad (18)$$

The formulation of start-up cost uses the tight formulation from (Morales-España, Latorre, & Ramos, 2013).

$$\delta_{t,g,s} \leq \sum_{i=TSU_{g,s}}^{TSU_{g,s+1}-1} sdn_{t-i,g}\,, \forall\, t \in [TSU_{g,s+1}, T], g, s \quad (19)$$

$$\sum_s \delta_{t,g,s} = sup_{t,g}, \forall\, t, g \quad (20)$$

Equation (19) controls the time since the last shutdown and (20) ensures that only one start-up cost value is selected at start up.

Minimum up and down times are enforced by equations (21) and (22). Equation (21) guarantees that unit g starts up only once over the last TU_g periods. Equation (22) ensures that only units that had been started up before can be shut down.

$$\sum_{i=t-TU_g+1}^{t} sup_{i,g} \;\leq\; qon_{t,g}, \forall\, t \in [TU_g, T], g \quad (21)$$

$$\sum_{i=t-TD_g+1}^{t} sdn_{i,g} \le N(g) - qon_{t,g}, \forall\, t \in [TD_g, T], g \tag{22}$$

Ramping limits are implemented by

$$\begin{aligned} qp_{t,g,p} - qp_{t-1,g,p} & \\ &\le \left(qon_{t,g} - sup_{t,g}\right)R_g - \underline{C}_{g,p} sdn_{t,g} \\ &+ \min\left(\overline{C}_{g,p}, \max\left(R_g, \underline{C}_{g,p}\right)\right) sup_{t,g}, \forall\, t, g, p \end{aligned} \tag{23}$$

$$\begin{aligned} qp_{t-1,g,p} - qp_{t,g,p} & \\ &\le \left(qon_{t,g} - sup_{t,g}\right)R_g - \underline{C}_{g,p} sup_{t,g} \\ &+ \min\left(\overline{C}_{g,p}, \max\left(R_g, \underline{C}_{g,p}\right)\right) sdn_{t,g}, \forall\, t, g, p \end{aligned} \tag{24}$$

$$sup_{t,g} - sdn_{t,g} = qon_{t,g} - qon_{t-1,g}, \forall\, t, g \tag{25}$$

Operation of pumped storage plants is subject to the equations

$$qpsp_{h,g}\, \eta_g \le \overline{C}_g, \forall\, t, g \in PSP \tag{26}$$

$$ppsp_{t,g} \le \overline{C}_g, \forall\, t, g \in PSP \tag{27}$$

$$qstor_{t,g} - qstor_{t-1,g} = ppsp_{h,g}\, \eta_g - qpsp_{h,g} \tag{28}$$

$$qstor_{t,g} \le \overline{STOR}_g, \forall\, t, g \in PSP \tag{29}$$

Finally, the clustered integer variables are limited to the total number of plants installed of power plant type g, such that $qon_{t,g} \le N_g$, $sup_{t,g} \le N_g$, $sdn_{t,g} \le N_g$.

The MIP formulation of the power market model MEDEA comprises of equations (9) to (29). In its LP version, MEDEA makes use of equations (9), (15) to (18) and (26) to (29). The market clearing conditions (10) and (11) are modified such that no integer variables are included. The capacity constraints in equations (12) to (14) are replaced by an upper limit on power plant generation.

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Universität für Bodenkultur Wien
Department für Wirtschafts- und Sozialwissenschaften
Institut für nachhaltige Wirtschaftsentwicklung
Feistmantelstrasse 4, 1180 Wien
Tel: +43/1/47 654 – 73600
Fax: +43/1/47 654 – 73109
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