District heating systems under high carbon prices: the role of the pass-through from emission to power prices

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Abstract

Low emission prices have prompted discussion about political measures aimed at increasing the cost of carbon emissions. These costs affect district heating system operators (DHSO), often municipal utilities, that use a variety of (emission intense) heat generation technologies. We examine whether DHSOs 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 from 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 significantly higher than required to make low-emission DHSO 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 CO_2e) in 2008 to an average of 7.71 €/t CO_2e 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.

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 operators (DHSO), 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. To the best of our knowledge, so far there is no literature explicitly considering the effects of emission prices on district heating systems. 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 levels 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.

Apart from potential endogeneity issues, regression analysis is necessarily based on historical observations. Extrapolation from historical data, which does not include (very) high emission prices, may lead to considerable bias, in particular in non-linear systems such as power systems.

Our modelling effort 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 A stylized model of district heating operations

2.1 Cost minimization in district heating systems

District heat 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 cost-minimizing 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 affected by the prevailing prices for electricity and emissions.

To analyse the effect of emission allowance prices on the decisions of district heating suppliers, a simplified portfolio consisting of co-generation units C and natural gas boilers B is considered. The cost function of the CHP operator is given by

$$\mathrm{C} = p_f q_f^B + p_e em_f q_f^B + p_f q_f^C + p_e em_f q_f^C - p_{el}\eta_{el} q_f^C \qquad (1)$$

where p denotes prices of fuel f (e.g. coal or natural gas), emissions e and electricity el, and q denotes quantities of fuel used in boiler B or CHP C. 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. At each point in time, heat generation from the portfolio has to match heat demand from the system, such that $q_f^B \eta_{th}^B + q_f^C \eta_{th}^C = d_{th}$.

The corresponding cost-minimization problem can be represented by the Langrangian

$$\begin{aligned}\mathcal{L}(q_f^B, q_f^C, \lambda) = {} & p_f q_f^B + p_e em_f q_f^B + p_f q_f^C + p_e em_f q_f^C - p_{el}\eta_{el} q_f^C \\ & - \lambda\left(q_f^B \eta_{th}^B + q_f^C \eta_{th}^C - d_{th}\right)\end{aligned} \qquad (2)$$

The first-order conditions of the problem in (2) allow to express shadow prices (cost) of heat generated by a heat boiler and a CHP-plant, respectively.

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

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

As long as sufficient capacities are available (e.g. in summer, when space heating demand is low), a cost minimizing operator will dispatch the lowest cost unit first. CHP units will have an absolute cost advantage over boilers ($c_{th}^{C} \leq c_{th}^{B}$), if the 'mark-up' of the electricity price over fuel and emission cost is sufficiently high.

$$\frac{p_{el}}{(p_f + p_e em_f)} \geq \frac{\eta_{th}^{B} - \eta_{th}^{C}}{\eta_{th}^{B}\eta_{el}^{C}} \tag{5}$$

Boilers will be dispatched when electricity prices are low (below the threshold in (5)) or when CHP units are capacity constrained (which is typically the case in winter when space heating demand peaks).

2.2 Effect of rising emission prices on district heating systems

Upon the introduction of measures to increase the emission price p_e the emission cost of CHP units and boilers will increase. Moreover, under the EU ETS a rising emission price will also affect generation costs of emission-intense power generators, who will pass some of the cost increase on to electricity prices p_{el}. Thus, the electricity price depends, amongst others, on the emission price, i.e. $p_{el}(\cdot, p_e)$.

Rising electricity prices generate additional revenues for CHP units from electricity sales. If these additional revenues outweigh the additional generation cost, district heating companies benefit from rising emission prices. In other words, the total cost of district heat generation $c^{tot} = c_{th}^{C} q_{th}^{C} + c_{th}^{B} q_{th}^{B}$ need to decline in emission prices. This will be the case if

$$\frac{\partial c^{tot}}{\partial p_e} = \frac{\partial c_{th}^{C}}{\partial p_e} q_{th}^{C} + c_{th}^{C} \frac{\partial q_{th}^{C}}{\partial p_e} + \frac{\partial c_{th}^{B}}{\partial p_e} q_{th}^{B} + c_{th}^{B} \frac{\partial q_{th}^{B}}{\partial p_e} < 0 \tag{6}$$

To simplify this expression, we make use of the fact that (exogenous) heat demand d_{th} must be supplied entirely from the district heating portfolio, such that $q_{th}^{C} + q_{th}^{B} = d_{th} \Rightarrow \frac{\partial q^B}{\partial p_e} = -\frac{\partial q^C}{\partial p_e}$. Using this result, we can rewrite the 'declining total cost-condition' as

$$\frac{\partial c_{th}^{C}}{\partial p_e} q^C + \frac{\partial c_{th}^{B}}{\partial p_e} q^B < (c_{th}^{B} - c_{th}^{C}) \frac{\partial q^C}{\partial p_e} \tag{7}$$

The inequality in (7)relates produced quantities from boilers and CHPs to these units' heat cost. Using the identity $q^B = q^T - q^C$, with q^T being total heat production from emission intense generators, equation (7) can be rearranged to yield the lower threshold on the pass-through from emission prices to power prices for which a district heating system with a given share of CHP heat generation and given electrical efficiency reduces its total cost.

In general, total costs of heat generation are declining in emission prices, if

$$\frac{\partial p_{el}}{\partial p_e} > \underbrace{\left(\frac{q^T - q^C}{q^C} \frac{\eta_{th}^{C}}{\eta_{th}^{B}\eta_{el}^{C}} + \frac{\eta_{th}^{B}}{\eta_{th}^{B}\eta_{el}^{C}}\right) em_f}_{A} \underbrace{- \frac{(c_{th}^{B} - c_{th}^{C})}{p_{el}} \varepsilon_{s^C}^{p_{el}} \frac{\eta_{th}^{C}}{\eta_{el}^{C}} \frac{\partial p_{el}}{\partial p_e}}_{B} \tag{8}$$

where $\varepsilon_{s^C}^{p_{el}} = \frac{\partial q^C}{\partial p_{el}} \frac{p_{el}}{q^C} \geq 0$ is the electricity price elasticity of heat supply from CHP units.

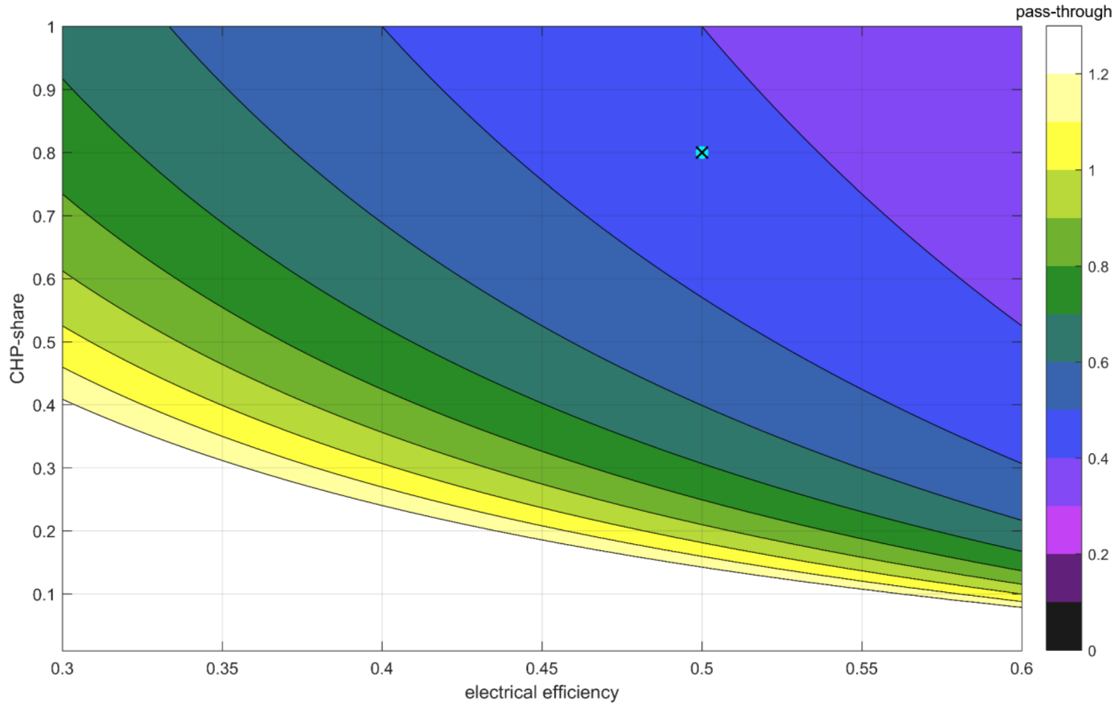

Figure 1: Minimally required pass-through for total cost reduction. Dot indicates the lowest pass-through level compatible with cost reduction for a district heating system with an electrical efficiency of 0.5 and a share of CHP heat generation of 0.8

Part A of the right-hand side of (8) is strictly positive for district heating portfolios, while the sign of B depends on the difference in heat cost between boilers and CHP units. B will be zero either if CHP units are capacity constrained (i.e. $\varepsilon_{s^C}^{p_{el}} = 0$) or if the heat cost of boilers and CHP units is equal. If i) CHP units have a cost advantage (cf. equation (5)) the whole of B will be negative, lowering the threshold for the minimally required pass-through from emission cost to electricity prices. On the other hand, if ii) electricity prices are so low that boilers have a heat cost advantage, heat will be preferentially generated in boilers, up to the available boiler capacity. Heat generation from CHP units is at the minimal level. In consequence, heat generation does not change with the electricity price, i.e. $\varepsilon_{s^C}^{p_{el}} = 0$. This holds true until the electricity price reaches a level at which $c_{th}^B = c_{th}^C$ and we are back in case i). Hence, we can restrict further analysis to the most adverse case (highest level of pass-through required for total cost reduction) in which B equals zero and (7) simplifies to

$$\frac{\partial p_{el}}{\partial p_e} > \left(\frac{q^T - q^C}{q^C}\frac{\eta_{th}^C}{\eta_{th}^B \eta_{el}^C} + \frac{\eta_{th}^B}{\eta_{th}^B \eta_{el}^C}\right) em_f \qquad (9)$$

Figure 1 depicts the minimal total cost reducing pass-through for given shares of CHP heat generation in total emission intense heat generation and for given electrical efficiency of CHP units. As is to be expected, a high CHP share and high electrical efficiency both lead to lower required pass-through levels. At CHP shares below 0.4 the pass-through level required by units of low electrical for total cost reduction exceeds 1.2, a level markedly above the estimates reported in the literature.

Table 1 summarizes the above results for specific district heating system configurations and provides an exemplary overview over the minimum requirements for cost reduction when CHP units do not face a cost-advantage and the corresponding mark-up of electricity prices over fuel and emission cost. For district heating systems with the least efficient power generators, the minimal pass-through compatible with reduction of total cost is more than twice as high (0.759) as for district heating systems with the most efficient power generators (0.352). More typical district heating systems (electrical efficiency 0.4) are able to reduce their cost with rising emission prices, provided that at least 55.6% of the increase in emission prices is passed on to electricity prices.

Table 1: Effects of technical parameters of heat generation units

(total efficiency = 0.8; boiler efficiency = 0.9)	Minimal electricity price mark-up over fuel and emission cost for cost advantage of CHP units (see (5))	Minimal pass-through from emission cost to electricity prices to guarantee total cost reduction ($q^C/q^T = 0.8$) (see (11))
Electrical efficiency 0.3	0.481	0.759
Electrical efficiency 0.4	0.389	0.556
Electrical efficiency 0.5	0.333	0.433
Electrical efficiency 0.6	0.296	0.352

In the following, we use the power system model MEDEA to investigate the effect of emission prices on power prices, i.e. to estimate the pass-through $\partial p_{el}/\partial p_e$. Power plant dispatch and resulting power prices are derived for emission prices in the range of 7.71 €/t CO_2e (which is equal to the average EUA price in 2015) to 72.71 €/t CO_2e, given the current inventory of power plants. 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 of the power system in the common bidding zone in Austria and Germany. Its mathematical formulation is similar to Palmintier (2013). 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 approach to account for inflexibilities in thermal power generation[1].

Within the common bidding area of Austria and Germany, 893 conventional power plants are included. Each conventional plant 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.).

[1] We acknowledge that the marginals on the balancing equation in a Mixed-Integer Linear program (MIP) may not be considered to be market prices, as those prices are not necessarily market clearing (Huppmann and Siddiqui, 2016). Thus, we complement our estimates with results from a simplified LP version of the power system model MEDEA (see Appendix A).

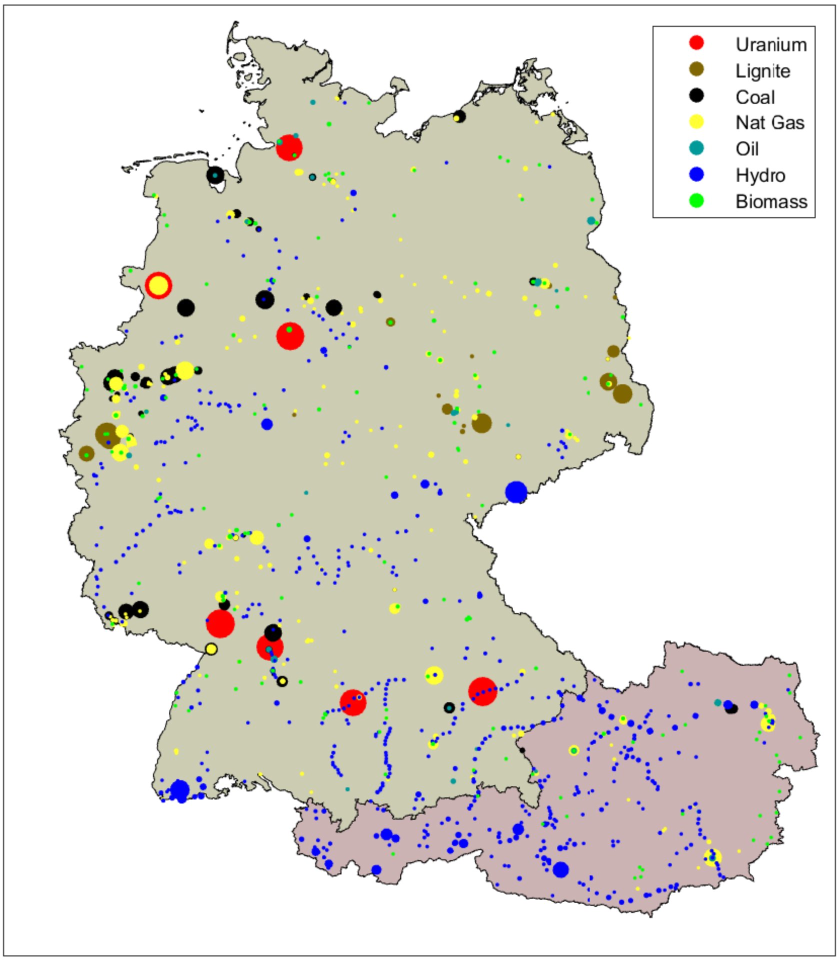

Figure 2: Thermal and hydro power plants in Germany and Austria (Dot size proportional to power plant capacity)

Technical parameters of power plant operation are represented in detail. Start-up of a plant requires 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 version of the model, relaxing the integer variables, for the whole year. 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 demand (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 2.

Table 2: Descriptive Statistics of Power and Heat Demand

	Unit	Min	Max	Mean	Std Dev	Source
Residual power demand	GWh/h	20.09	68.28	43.60	9.66	eex transparency
District heating demand	GWh/h	4.71	46.26	16.44	9.42	Own calculations

3.2.2 Conventional plants for the production of power and heat

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 our own research. In total, our database contains 1326 thermal and hydro power plants with an electrical capacity of 112.7 GW (see Figure 2). Further technical characteristics such as minimum up and down times follow Schröder et. al. (2013).

District heat can be supplied by co-generation plants included in our database. Alternatively, heat can be supplied from natural gas-fired boilers with a maximal capacity of 20 GW_{th}. Boiler efficiency is assumed at 0.9. Boilers as well as co-generation plants are not assigned to specific district heat grids. Thus, substitutability of heat generation units is overestimated.

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 3.

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 an electricity feed-in remuneration of 84 €/MWh. In consequence, biomass-fired plants are strictly running at available capacity.

Table 3: Descriptive Statistics of Energy and Emission Prices (eex, 2016)

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_2e	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 price of EUAs in 2015 (annual average of 7.71 €/t CO_2e), we increase realized daily emission prices in steps of 5 €/t CO_2e (up to an annual average emission price of 72.71 €/t CO_2e). The electricity base price (i.e. the annual average of the hourly spot price) is then used to approximate the pass-through by

$$\frac{\Delta p_{el}}{\Delta p_e} = \frac{p_{el}^s - p_{el}^{s-1}}{p_e^s - p_e^{s-1}} \qquad (10)$$

The resulting pass-through estimates are presented in **Fehler! Verweisquelle konnte nicht gefunden werden.** for the mixed-integer linear programming (MILP) formulation of MEDEA, which represents plant flexibility in detail and for the linear programming (LP) formulation of MEDEA. Our bottom-up analysis of the pass-through of emission prices to electricity prices shows that the pass-through level (between 0.75 and 1.17) is sufficiently high to make district heating operators of typical, moderately efficient natural gas power plants better off at higher emission prices (see **Fehler! Verweisquelle konnte nicht gefunden werden.** for details).

Irrespective of the chosen modelling approach, we see the pass-through decline from around 1.17 at emission prices around 10 €/t CO_2e to approximately 0.75 at emission prices near 60 €/t CO_2e (c.f. **Fehler! Verweisquelle konnte nicht gefunden werden.**). 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 fuel efficiency. Moreover, a change in operational patterns brought upon by rising emission prices explains the variation of MILP-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

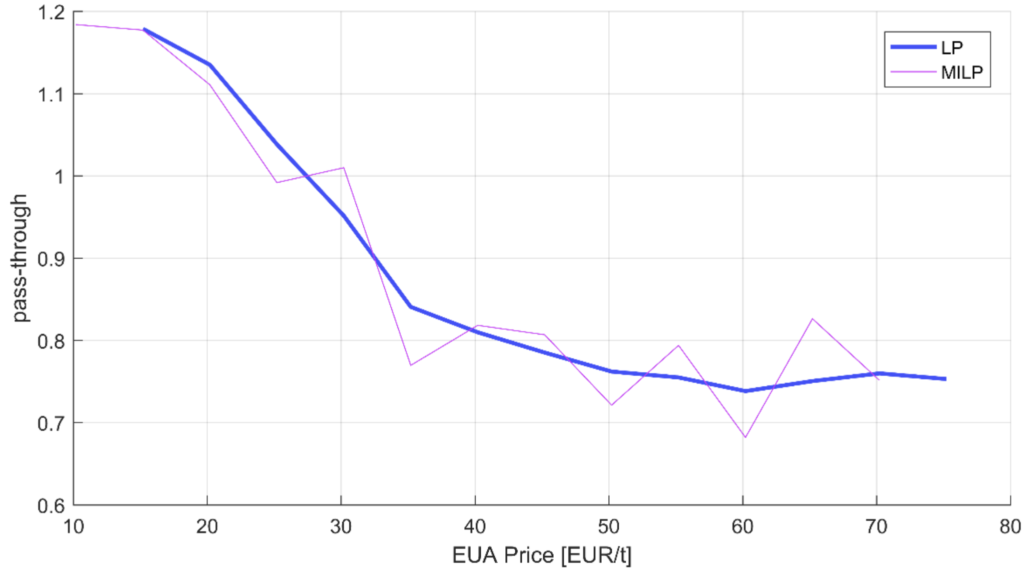

Figure 3: Estimated pass-through from emission cost to electricity prices

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 prices up to 15 €/t CO_2e, (marginal) increases in emission prices trigger the replacement of the most inefficient lignite-fired power plants by generation from not fully or not yet utilized coal-fired power plants. At moderate emission price levels, further increases in emission prices will cause a replacement of more lignite-fired power plants by coal-fired and also highly efficient natural gas-fired power plants. Up to an emission price level of about 32 €/t CO_2e, 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 CO_2e, 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.

As emission prices reach 55 €/t CO_2e, 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

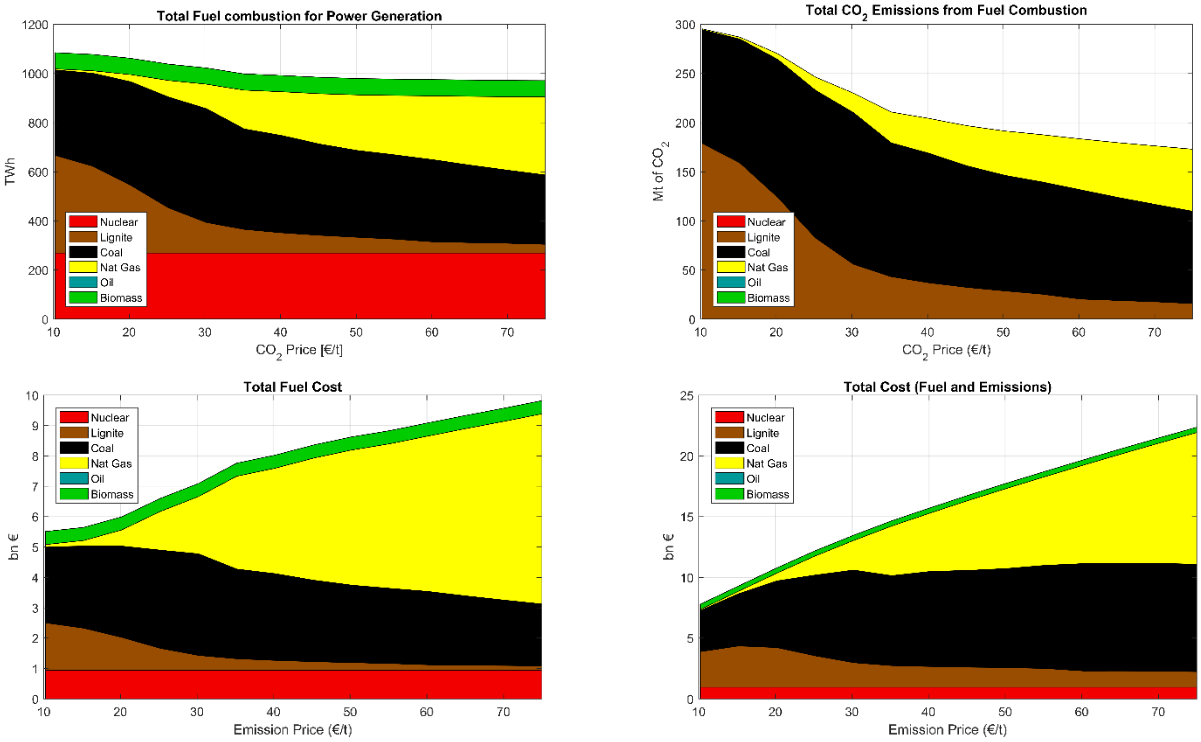

Figure 4: Results from Emission Price Scenarios

exceed heat generation. Any further increase in emission prices above 55 €/t CO_2e 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 mixed-integer linear formulation of MEDEA from the pass-through estimates of the linear programming 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 CO_2e and 30 €/t CO_2e. Similarly, at emission prices around 50 €/t CO_2e, small and flexible but comparatively inefficient natural gas turbines enter the market and provide additional flexibility through a large number of starts and stops.

5 Discussion

Fabra & Reguant (2014) provide central estimates of pass-through rates in the Spanish electricity market between 0.77 and 0.86 with standard deviations of 0.165 and 0.181, respectively. These estimates are based on observed emission price levels in the range of 20 €/t CO_2e. For the German electricity market, Hintermann (2014) estimates a pass-through rate of 1.024 with standard deviation of 0.069 for the hourly base price of electricity over the years from 2010 to 2014. During this period prices for emission allowances averaged 9.30 €/t CO_2e, with annual averages between 4.50 €/t CO_2e and 14.30 €/t CO_2e. Finally, Sijm et.al. (2006) cautiously provide empirical estimates for the German electricity market in 2005, warning of methodological difficulties related to their estimation strategy. Pointing out potential underestimation, pass-through is evaluated within the range of 0.6 to 1.17. At this time, prices for EU emission allowances averaged 18.25 €/t CO_2e.

Our estimates for the emission cost pass-through are consistently higher than the empirical estimates provided by Fabra & Reguant (2014) and Hintermann (2014). Although results from Fabra & Reguant (2014) are obtained for the Spanish electricity market and thus not fully comparable, we do identify several common causes that might lead to a consistent overestimation of pass-through rates by our techno-economic model. We did not estimate pass-through rates from observed data, but instead used 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"[2] (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 less efficient power generators in district heating systems will certainly not benefit from increasing emission prices (0.55).

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 immediate effect of 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.

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

6 Conclusion

We have shown that the emission price has a large effect on the power price through an almost complete pass-through of marginal cost to power prices at current emission price levels. 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 substantially higher than 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. In future research, we therefore aim to analyse the long-run effects of emission price increases in the context of the European power generation system.

7 Literature

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Appendix A

A.1 List of Variables and Parameters

A.1.1 Sets

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

A.1.2 Parameters

$\overline{C}_{g,p}$	maximum generation of product p by generator in cluster g [MW]
$\underline{C}_{g,p}$	minimum generation of product p by generator in cluster g [MW]
$\overline{STOR}_g$	capacity of storage reservoirs of storage plant g
$CSD_{g,f}$	use of fuel f of generator in cluster g on shut down [MWh]
$CSU_{g,f,s}$	use of fuel f of a generator in cluster g starting up from state s. [MWh]
$D_{t,p}$	Demand for product p at time t [MW]
N_g	number of generators in cluster g
$ORF_{g,l,f}$	use of fuel f at limit l of operating region of CHP plant in cluster g
$ORP_{g,l,p}$	output of product p at limit l of operating region of CHP plant in cluster g
$P_{t,eua}$	Emission allowance price at time t [€/t CO_2e]
$P_{t,f}$	Price of fuel f at time t [€/MWh]
$Q_{t,pv}$	solar energy generated at time t [MW]
$Q_{t,ror}$	energy generated by run-of-river plants at time t [MW]
$Q_{t,we}$	wind energy generated at time t [MW]
R_g	ramping rate of generator in cluster g [MW]
$SD_{g,p}$	maximum generation of product p at shut-down of generator in cluster g [MW]
$SU_{g,p}$	maximum generation of product p at start-up of generator in cluster g [MW]
em_f	emission factor of fuel f [t of CO_2 / MWh of fuel used]
$\eta_{g,f,p}$	efficiency of generator g using fuel f to generate product p
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]

A.1.3 Variables

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

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

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

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

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

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

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

$\delta_{t,g,s}$ 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

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

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

A.2 Mathematical description of the power system model MEDEA

MEDEA uses a mixed-integer linear programming formulation of the unit commitment problem for thermal units within the Austro-German bidding zone. Operation of pumped storage plants is formulated as a linear problem.

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

$$\min\left[\sum_{t,f}\left(P_{t,f}+em_f P_{t,eua}\right)\sum_{g}\left(qf_{t,g,f}+\sum_{s} CSU_{g,f,s}\; sup_{t,g}+CSD_{g,f} sdn_{t,g}\right)\right] \qquad (11)$$

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).

$$D_{t,pwr}-Q_{t,we}-Q_{t,pv}-Q_{t,ror} = \sum_{g}\left(qon_{t,g}\,\underline{C}_{g,pwr}+qp_{t,g,pwr}\right)+\sum_{g\epsilon PSP} qpsp_{t,g}-\sum_{g\epsilon PSP} ppsp_{t,g}\;,\forall t \qquad (12)$$

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 (12) 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 $D_{t,ht}$.

$$D_{t,ht} \le \sum_{g\epsilon CHP}\left(qon_{t,g}\underline{C}_{g,ht}+qp_{t,g,ht}\right)\;,\forall t \qquad (13)$$

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

$$qp_{t,g,p} \le \left(\overline{C}_{g,p}-\underline{C}_{g,p}\right)qon_{t,g}-\left(\overline{C}_{g,p}-SU_{g,p}\right)sup_{t,g}, \forall t, TU_g=1 \qquad (14)$$

$$qp_{t,g,p} \le \left(\overline{C}_{g,p}-\underline{C}_{g,p}\right)qon_{t,g}-\left(\overline{C}_{g,p}-SD_{g,p}\right)sdn_{t+1,g}, \forall t, TU_g=1 \qquad (15)$$

For cases in which $TU_g > 1$, constraints (14) and (15) can be replaced by

$$qp_{t,g,p} \leq (\overline{C}_{g,p} - \underline{C}_{g,p})qon_{t,g} - (\overline{C}_{g,p} - SU_{g,p})sup_{t,g} - (\overline{C}_{g,p} - SD_{g,p})sdn_{t+1,g}, \forall t, TU_g > 1 \quad (16)$$

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

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

$$\sum_l qconv_{t,g,l} = qon_{t,g} - sup_{t,g} - sdn_{t+1,g}, \forall g \in CHP \quad (17)$$

$$\sum_l qconv_{t,g,l}\, ORP_{g,l,p} = (\underline{C}_{g,p}qon_{t,g} + qp_{t,g,p}) - sup_{t,g}SU_{g,p} - sdn_{t+1,g}SD_{g,p}, \forall g \in CHP \quad (18)$$

$$\sum_l qconv_{t,g,l}\ ORF_{g,l,f} \leq qfuel_{t,g,f} \quad (19)$$

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

$$qon_{t,g}\ \underline{C}_{g,pwr} + qp_{t,g,pwr} \leq \sum_f \eta_{g,f,pwr}\ qf_{t,g,f}, \forall\ t, g \notin CHP \quad (20)$$

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

$$\delta_{t,g,s} \leq \sum_{i=TSU_{g,s}}^{TSU_{g,s+1}-1} sdn_{t-i,g}, \forall\ t \in [TSU_{g,s+1}, T], g, s \quad (21)$$

$$\sum_s \delta_{t,g,s} = sup_{t,g}, \forall\ t, g \quad (22)$$

Equation (21) controls the time since the last shutdown and (22) ensures that only one start-up cost value is selected at start up.

Minimum up and down times are enforced by equations (23) and (24). Equation (23) guarantees that unit g starts up only once over the last TU_g periods. Equation (24) ensures that only units that had been started up before can be shut down.

$$\sum_{i=t-TU_g+1}^{t} sup_{i,g} \leq qon_{t,g}, \forall\ t \in [TU_g, T], g \quad (23)$$

$$\sum_{i=t-TD_g+1}^{t} sdn_{i,g} \leq N(g) - qon_{t,g}, \forall\ t \in [TD_g, T], g \quad (24)$$

Ramping limits are implemented by

$$\begin{aligned} qp_{t,g,p} - qp_{t-1,g,p} \leq\ & (qon_{t,g} - sup_{t,g})R_g - \underline{C}_{g,p}sdn_{t,g} \\ & + \min\left(\overline{C}_{g,p}, \max(R_g, \underline{C}_{g,p})\right) sup_{t,g}, \forall\ t, g, p \end{aligned} \quad (25)$$

$$\begin{aligned} qp_{t-1,g,p} - qp_{t,g,p} \leq\ & (qon_{t,g} - sup_{t,g})R_g - \underline{C}_{g,p}sup_{t,g} \\ & + \min\left(\overline{C}_{g,p}, \max(R_g, \underline{C}_{g,p})\right) sdn_{t,g}, \forall\ t, g, p \end{aligned} \quad (26)$$

$$sup_{t,g} - sdn_{t,g} = qon_{t,g} - qon_{t-1,g}, \forall\ t, g \quad (27)$$

Operation of pumped storage plants is subject to the equations

$$qpsp_{h,g}\,\eta_g \leq \overline{C}_g, \forall\, t, g \in PSP \tag{28}$$

$$ppsp_{t,g} \leq \overline{C}_g, \forall\, t, g \in PSP \tag{29}$$

$$qstor_{t,g} - qstor_{t-1,g} = ppsp_{h,g}\,\eta_g - qpsp_{h,g} \tag{30}$$

$$qstor_{t,g} \leq \overline{STOR}_g, \forall\, t, g \in PSP \tag{31}$$

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

The mixed-integer linear (MILP) formulation of the power market model MEDEA comprises of equations (11) to (31). In its linear (LP) version, MEDEA makes use of equations (11), (17) to (20) and (28) to (31). The market clearing conditions (12) and (13) are modified such that no integer variables are included. The capacity constraints in equations (14) to (16) are replaced by an upper limit on power plant generation.