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The paper at hand examines the power system costs when a coal tax or a fixed bonus for renewables is combined with CO_2 emissions trading. It explicitly accounts for the interaction between the power and the gas market and identifies three cost effects: First, a tax and a subsidy both cause deviations from the cost-efficient power market equilibrium. Second, these policies also impact the power sector's gas demand function as well as the gas market equilibrium and therefore have a feedback effect on power generation quantities indirectly via the gas price. Thirdly, by altering gas prices, a tax or a subsidy also indirectly affects the total costs of gas purchase by the power sector. However, the direction of the change in the gas price, and therefore the overall effect on power system costs, remains ambiguous. In a numerical analysis of the European power and gas market, I find using a simulation model integrating both markets that a coal tax affects gas prices ambiguously whereas a fixed bonus for renewables decreases gas prices. Furthermore, a coal tax increases power system costs, whereas a fixed bonus can decrease these costs because of the negative effect on the gas price. Lastly, the more market power that gas suppliers have, the stronger the outlined effects will be.

Keywords: CO2 abatement, oligopoly, gas market, power market
JEL classification: C60, L13, Q02, Q48

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1. Introduction

The European Union and its member states have established a variety of policies to foster carbon dioxide (CO_2) abatement in the electricity sector. One EU-wide instrument is the European Union Emissions Trading System (EU-ETS), which defines an emissions quota and forces CO_2-intensive industries such as electricity generation, cement, paper or iron and steel production to buy allowances to emit CO_2. Besides the EU-ETS, there are various national CO_2 reduction policies in place such as numerous subsidy regimes for renewable (RES) power generation or a coal tax levied in the Netherlands. Emissions quota systems such as the EU-ETS are considered to be a cost efficient instrument to achieve a defined CO_2 abatement target (see, e.g., Böhringer and Rosendahl (2011)). Given a fixed CO_2 emissions quota, additional policies such as RES subsidies or taxes have no effect on CO_2 reduction but cause deviations from the cost-efficient CO_2 reduction. Hence, given constant fuel costs for different policies, it can be shown analytically that taxes or subsidies increase the costs of the power system.

However, there are good reasons to claim that fuel costs, at least for natural gas, are not constant but rather influenced by climate policy interventions: First, climate policies affect the gas demand of the power sector. The EU-ETS or a coal tax, for example, fosters fuel switching from coal to gas. RES subsidies, on the contrary, have a negative impact on power generation from natural gas. Second, natural gas supply in Europe is highly concentrated. In 2012, the European OECD member countries purchased roughly 70% of their total gas demand from Russia, Norway, Algeria or the Netherlands. In each of these countries, one state-owned gas company manages almost the entirety of gas sales. Given the high market concentration, changing gas demand functions through policy intervention can influence gas prices significantly. In this context, Newbery (2008) has shown analytically that the EU-ETS reduces the price elasticity for gas consumption in the electricity sector, strengthens the market power of gas suppliers and increases gas prices. Increasing gas prices imply higher power system costs.

The overall power system cost effect of combining other carbon reduction policies such as a coal tax or a fixed bonus for RES with the EU-ETS seems unclear: On the one hand, combining the EU-ETS with additional policies causes efficiency losses (e.g., tax distortions). On the other hand, policies and their effects on gas demand may cause a gas price reaction in the oligopolistic gas market. However, the direction of the change in gas price and therefore the overall effects on power system costs are ambiguous.

Thus, the paper at hand aims at answering the question as to how carbon reduction policies in combination with the EU-ETS affect the power system costs and therefore the costs of CO_2 abatement, accounting for gas market effects. This research focuses on two carbon reduction policies which I introduce in addition to the EU-ETS: A location- and technology-independent fixed bonus RES subsidy and a coal tax. The analysis is conducted following four hypotheses:

1. A coal tax increases gas prices, a fixed RES bonus decreases gas prices. (H1)
2. A coal tax increases power system costs compared to an EU-ETS-only regime. (H2)
3. A fixed RES bonus reduces power system costs compared to an EU-ETS-only regime. (H3)
4. Higher market power in the gas market amplifies the outlined effects. (H4)

In order to assess these hypotheses, a stylized theoretical model is used to analyze the interaction of gas and electricity markets given the respective policies and the EU-ETS. From this theoretical analysis, I identify three effects of a policy intervention on power system costs. First, applying the example of a RES subsidy, I find that the direct impact of a subsidy on the power generation depends on the fuel type. Gas generation decreases, whereas coal and RES generation increases. This *direct effect* of a subsidy on power system costs is always positive, i.e., in the first step system costs increase due to the subsidy. However, secondly, if the subsidy affects gas price and demand, the changing gas price leads to a different equilibrium on the power market. This effect is denoted as *indirect quantity effect.* Third, the subsidy changing the gas price affects the costs of each unit of gas purchased by the power sector. This effect is denoted as the *indirect price effect.* Both indirect effects of a subsidy can be positive or negative. If they are negative, the effects may overcompensate the direct cost effect. Thus, a climate policy such as a RES subsidy can, in theory, reduce power system costs.

To quantify these effects and to verify the hypotheses for a real-world example of the European power and gas markets, I develop a calibrated simulation tool which models the long-term interaction of both markets by combining a power market and a gas market simulation model. The approach that is commonly used to simulate electricity markets in partial analyses is large-scale linear dispatch and investment simulation models. In this analysis, the model DIMENSION is applied (see Richter (2011)). Partial analyses concerning market power on the natural gas market are often conducted using mixed complementarity problem (MCP) models, enabling the simulation of Cournot oligopolies. In this study, I apply the long-term global gas market model COLUMBUS (see Hecking and Panke (2012) or Growitsch et al. (2013)). Both models are integrated as follows: The power market model is used to derive a gas demand function, which is then applied in the gas market model. The resulting gas price is then fed back into the power market model.

The integrated simulation model is applied to three scenarios for the years 2015, 2020, 2030 and 2040. The scenarios include an EU-ETS only scenario as a reference, an EU-ETS plus coal tax scenario and third, an EU-ETS plus fixed RES bonus scenario.

Concerning H1, I find from the simulation that a coal tax has ambiguous effects on gas prices whereas for each fixed RES bonus scenario, the gas prices decrease. H2 holds, i.e. a coal tax increases power system costs. Furthermore, the results reveal that a fixed bonus RES subsidy can decrease overall costs of the power system (H3): In the simulated cases the indirect price effect overcompensates the increasing costs incurred by the sum of the direct and indirect quantity effect. The simulation also confirms H4, i.e., that higher gas market power amplifies the effects outlined above.

The policy implications of these findings should not suggest that CO_2 abatement becomes more efficient through a fixed RES bonus. The results should only reveal that the costs of the *European power system* decrease. Decreasing costs of the power system result from decreasing purchase costs for natural gas. Therefore, lower power system costs imply lower revenues for natural gas suppliers. Hence, one motive for introducing a fixed bonus RES subsidy could be to redistribute welfare from non-European gas suppliers to European power utilities or end users.

This research is based on literature on the economic effects of overlapping climate policies[1]. This strand of literature traces back to Tinbergen (1952), who argues that the number of policies should equal the number of policy objectives. In other words, if the sole objective was to reduce CO_2 emissions, only one policy should be used. Sijm (2005), for example, concludes that in the presence of a CO_2 emissions quota system, the CO_2-reduction effect of any other policy becomes zero. In this light, Böhringer et al. (2008) show that additional CO_2 emission taxes for sectors covered by the EU-ETS have no effect on CO_2 reduction but increase overall costs. Concerning RES-E subsidies, Böhringer and Rosendahl (2011) argue that, combined with the EU-ETS, these policies increase CO_2 abatement costs without affecting CO_2 reduction.

[1] For a detailed overview see Fischer et al. (2010) or del Río González (2007).

However, literature also provides economic justifications in favor of interacting policies (see, for example, Sorrell and Sijm (2003))[2]: Additional policies may correct market failures with respect to technology innovation and market penetration, raise fiscal incomes, redistribute welfare, reduce other environmental externalities or reduce the import dependence on oil and gas imports. Lastly, some argue that additional policies could improve the static efficiency of the EU-ETS, i.e., correct market failures other than the negative externality of CO_2 emissions such as supply-side concentration. Bennear and Stavins (2007), for example, state that market power plus environmental externalities can create the need for multiple policies. Whereas Bennear and Stavins (2007) focus on market power and externalities in the same market, Newbery (2008) takes into account market power in the upstream market. According to Newbery (2008), the EU-ETS, internalizing CO_2 emissions in the power sector, fosters market power in the upstream fuel market (natural gas) thereby increasing CO_2 abatement costs.

In this light, the paper at hand contributes to the existing literature on overlapping climate policies in the electricity sector by assessing two policies in combination with the EU-ETS, thereby explicitly accounting for oligopolistic behavior in the gas market. It extends the current debate on overlapping regulations by showing that policy interventions do not only affect the regulated market but also have feedback effects on upstream markets and potential market power, as seen in the gas market. Furthermore, this research shows that the policies in focus are capable of redistributing welfare between market participants across different markets.

Additionally, the paper at hand contributes to the literature on modeling electricity and gas market interaction in three dimensions: First, the model developed in this paper combines the high level of detail of LP power market simulations with the oligopolistic behavior of the MCP gas market models. Second, the electricity sector's inverse gas demand functions are derived endogenously during the simulation. Third, the model enables the simulation of gas market power on power utilities.

The paper is structured as follows: In Section 2, I show the interactions between policies, the gas market and the power market and the resulting cost effects in a stylized theoretical analysis. Section 3 presents the methodology used in this paper, i.e., the combining a LP power market model with a MCP gas market model in a numerical analysis. The model parameterization and the scenario design are discussed in Section

[2] However, it is important to stress that analyzing the effectiveness and efficiency of currently applied policies with respect to these justifications is beyond the scope of this paper.

4. Section 5 assesses the hypotheses of this paper by applying the integrated power and gas market model for a case study of 11 European countries. Section 6 concludes.

2. A stylized model of carbon reduction policies affecting power system costs

In this section, the interactions between carbon reduction policies, power generation by fuel type and power system costs are analyzed using a stylized model. In a first step, a fixed gas price (i.e., no interaction with the gas market) is assumed. In a second step, the reaction of the gas market to changing gas demand from the power sector is included. Thirdly, a graphical analysis of the interaction is presented.

The modeled electricity market is equipped with three technologies: coal C, gas G and renewables R. Let x_C, x_G and x_R denote the amount of electricity supplied by each technology, respectively. K denotes the total power system costs. The power generation of each technology depends on the fixed bonus subsidy for renewables[3] s and the specific full costs of power generation g, c and r, i.e., long-run marginal costs.[4] Variables c and r are assumed to be constant, whereas the gas generation costs g are affected by changing gas prices. Subsidies for renewables affect gas demand and, therefore, gas prices. Thus, the gas-specific generation costs g depend on the subsidy s. This yields the following power system costs:

$$\begin{gathered} K(x_R(s,g(s)), x_C(s,g(s)), x_G(s,g(s)), g(s)) = \\ (r-s)x_R(s,g(s)) + sx_R(s,g(s)) + cx_C(s,g(s)) + g(s)x_G(s,g(s)). \end{gathered} \tag{1}$$

Electricity demand D is inelastic and equals the sum of the generated power of all three technologies,

$$D = x_R + x_C + x_G. \tag{2}$$

There is a cap E on CO_2 emissions. Total emissions depend on the specific CO_2 emissions per technology, e_C, e_G and e_R. The renewable emissions e_R are assumed to be zero, and $e_C > e_G$. Total emissions are given by:

$$E = e_C x_C + e_G x_G. \tag{3}$$

[3] In the following, the fixed bonus subsidy for renewables becomes the central focus of this analysis. The effects of a coal tax are similar.

[4] The full costs of power generation comprise capital costs, fixed operation and maintenance costs and fuel costs. The specific full costs represent the full-costs per unit, i.e., long-run marginal costs.

For a situation in which $c < g < r$ and $s = 0$. Let x_C^0, x_G^0 and x_R^0 denote the equilibrium power generation and DR the residual demand. Assume $x_C^0 > 0$ and $x_G^0 > 0$. Then,

$$DR = D - x_R^0 = x_C^0 + x_G^0. \tag{4}$$

2.1. Cost effects given fixed gas prices

In the following, I derive the cost effects of a fixed bonus RES subsidy on power system costs, given that gas prices are not affected by the subsidy.

Proposition 1: Assuming a constant gas price and, hence, constant generation costs g, a subsidy s increases power system costs K.

Although this is implied already by the first welfare theorem, the following proof turns out to be instructive for the further discussions in this Section.

Proof of Proposition 1:
Differentiating the power system costs K with respect to the subsidy s yields:

$$\begin{aligned}\frac{dK}{ds} &= \frac{\partial K}{\partial x_R}\frac{dx_R}{ds} + \frac{\partial K}{\partial x_C}\frac{dx_C}{ds} + \frac{\partial K}{\partial x_G}\frac{dx_G}{ds}\\ &= \frac{\partial K}{\partial x_R}\frac{\partial x_R}{\partial s} + \frac{\partial K}{\partial x_C}\frac{\partial x_C}{\partial s} + \frac{\partial K}{\partial x_G}\frac{\partial x_G}{\partial s}\\ &= r\frac{\partial x_R}{\partial s} + c\frac{\partial x_C}{\partial s} + g\frac{\partial x_G}{\partial s}.\end{aligned} \tag{5}$$

Next, two Lemmata are needed to proceed the proof of Proposition 1.

Lemma 1: Subsidy s increases coal-fired generation x_C, whereas it decreases gas-fired generation x_G, i.e., $\frac{\partial x_C}{\partial s} > 0$ and $\frac{\partial x_G}{\partial s} < 0$.

Proof of Lemma 1:
Equations 3 and 4 yield the equilibrium quantities x_C^0 and x_G^0, respectively, i.e., the equilibrium given the residual demand and emission constraint:

$$x_C^0 = \frac{E - e_G DR}{e_C - e_G} \tag{6}$$

$$x_G^0 = \frac{e_C DR - E}{e_C - e_G}. \tag{7}$$

Let subsidy s have a positive impact on renewable generation or, put differently, decrease residual demand DR, that is:

$$\frac{\partial DR}{\partial s} = -\frac{\partial x_R}{\partial s} < 0. \tag{8}$$

Thus, assuming a constant CO_2 cap E and using Equations 6, 7 and 8 yields:

$$\frac{\partial x_C}{\partial s} = \frac{\partial DR}{\partial s}\frac{-e_G}{e_C - e_G} > 0 \tag{9}$$

$$\frac{\partial x_G}{\partial s} = \frac{\partial DR}{\partial s}\frac{e_C}{e_C - e_G} < 0. \tag{10}$$

This proves Lemma 1.

Lemma 1 implies that increasing generation of renewables through a subsidy in combination with a CO_2 quota system increases coal-fired generation whereas gas-fired generation, i.e., the more expensive but less CO_2-intensive technology, decreases.

Hence, from Equations 5, 9 and 10, the total cost effect of a renewable subsidy can be derived to equal:

$$\frac{dK}{ds} = r\frac{\partial x_R}{\partial s} + c\frac{e_G}{e_C - e_G}\frac{\partial x_R}{\partial s} - g\frac{e_C}{e_C - e_G}\frac{\partial x_R}{\partial s} = \frac{\partial x_R}{\partial s}(r + \frac{ce_G - ge_C}{e_C - e_G}). \tag{11}$$

Since the generation of renewables x_R increases with the subsidy, a subsidy increases total power system costs if and only if the term in brackets becomes positive. Rearranging Equation 11 yields:

$$g < r(1 - \frac{e_G}{e_C}) + c\frac{e_G}{e_C}. \tag{12}$$

Lemma 2: $g < r(1 - \frac{e_G}{e_C}) + c\frac{e_G}{e_C}$ is equivalent to $x_G^0 > 0$.

Proof of Lemma 2:
Assume that Condition 12 does not hold, i.e.,

$$g = \hat{g} + h > r(1 - \frac{e_G}{e_C}) + c\frac{e_G}{e_C} = \hat{g} \quad , h > 0. \tag{13}$$

Thus, the power system costs K^0 in the equilibrium become:

$$K^0 = (\hat{g} + h)x_G^0 + rx_R^0 + cx_C^0 = r(1 - \frac{e_G}{e_C})x_G^0 + c\frac{e_G}{e_C}x_G^0 + rx_R^0 + cx_C^0 + hx_G^0. \quad (14)$$

Assume another situation with $x_G^1 = 0$ and system costs K^1. Zero gas-fired generation results allows for more available emission allowances compared to the situation in which $x_G^0 > 0$, thus:

$$x_C^1 = x_C^0 + \frac{e_G}{e_C}x_G^0. \quad (15)$$

Since power demand is assumed to be constant and $\frac{e_G}{e_C} < 1$, generation of renewables has to increase in order to compensate for the decreasing gas-fired generation:

$$x_R^1 = x_R^0 + (1 - \frac{e_G}{e_C})x_G^0. \quad (16)$$

Thus, the power system costs K^1 become:

$$K^1 = rx_R^0 + r(1 - \frac{e_G}{e_C})x_G^0 + cx_C^0 + c\frac{e_G}{e_C}x_G^0 < K^0, \text{ since } h > 0. \quad (17)$$

Hence, $x_G^0 > 0$ and $g > r(1 - \frac{e_G}{e_C}) + c\frac{e_G}{e_C}$ would not be a cost-efficient equilibrium. This **proves Lemma 2.**

From Lemmas 1 and 2 it follows that, given $x_C^0 > 0$, $x_G^0 > 0$, a binding CO_2 cap, $c < g < r$ and fixed gas price, i.e., fixed generation costs g , a positive subsidy for renewables s increases power system costs K. This **proves Proposition 1**.

The economic interpretation of Proposition 1 is that a subsidy for renewables has the same effect as the exchanging of one unit of gas-fired generation for a more expensive unit of a bundle of renewable generation and coal-fired generation, which is an equally CO_2-intensive option as gas-fired electricity generation.

2.2. Cost effects accounting for gas market reaction

The Section before has shown that a RES subsidy increases power system costs, given that the gas price is constant. In the following Section, the power system costs are derived given the assumption that the gas price is affected by the RES subsidy.

Proposition 2: Assuming that the subsidy s affects the gas demand function and therefore the equilibrium gas price and the gas generation costs g, the overall effect of a subsidy s on power system costs K is ambiguous.

Proof of Proposition 2:
Differentiating K with respect to s yields:

$$\begin{aligned}\frac{dK}{ds} = &\frac{\partial K}{\partial x_R}\left(\frac{\partial x_R}{\partial s} + \frac{\partial x_R}{\partial g}\frac{\partial g}{\partial s}\right)\\ &+ \frac{\partial K}{\partial x_C}\left(\frac{\partial x_C}{\partial s} + \frac{\partial x_C}{\partial g}\frac{\partial g}{\partial s}\right)\\ &+ \frac{\partial K}{\partial x_G}\left(\frac{\partial x_G}{\partial s} + \frac{\partial x_G}{\partial g}\frac{\partial g}{\partial s}\right)\\ &+ \frac{\partial K}{\partial g}\frac{\partial g}{\partial s}.\end{aligned} \tag{18}$$

Thus, the subsidy affects electricity generation of each fuel type directly. Since the subsidy also affects the gas price and therefore gas generation costs, a subsidy also affects the electricity generation indirectly via g. Rearranging Equation 18 yields:

$$\begin{aligned}\frac{dK}{ds} = &\, r\underbrace{\frac{\partial x_R}{\partial s}}_{(+)} + c\underbrace{\frac{\partial x_C}{\partial s}}_{(+)} + g\underbrace{\frac{\partial x_G}{\partial s}}_{(-)} && \text{(direct effect)}\\ &+ \left(r\underbrace{\frac{\partial x_R}{\partial g}}_{(+)} + c\underbrace{\frac{\partial x_C}{\partial g}}_{(+)} + g\underbrace{\frac{\partial x_G}{\partial g}}_{(-)}\right)\underbrace{\frac{\partial g}{\partial s}}_{(?)} && \text{(indirect quantity effect)}\\ &+ x_G\underbrace{\frac{\partial g}{\partial s}}_{(?)}. && \text{(indirect price effect)}\end{aligned} \tag{19}$$

The direct effects of a subsidy have been discussed in the previous section: Subsidy s decreases x_G but increases both x_C and x_R. The direct cost effect is positive (see Proposition 1). When taking into account the gas market reaction, a subsidy s can increase or decrease the gas price and therefore gas generation costs g.[5] Hence, the sign of $\frac{\partial g}{\partial s}$ is ambiguous. A subsidy has two indirect effects on total power system costs.

[5] Gas generation costs g comprise constant fix costs and fuel costs. Latter are proportional to the gas price depending on the gas plant's degree of efficiency. Therefore gas price changes are in a positive linear relation to changes of gas generation costs g.

First, the indirect price effect is quite intuitive: If the subsidy s increases/decreases the gas price, i.e., gas generation costs g, the costs of gas purchased by the power sector increase/decrease. Second, the indirect quantity effect is more complex, as explained by Lemma 3:

Lemma 3: The indirect quantity effect becomes negative if and only if $\frac{\partial g}{\partial s} < 0$, i.e., if and only if a subsidy decreases the gas price.

Proof of Lemma 3:
It is sufficient to show that $\tau = r\frac{\partial x_R}{\partial g} + c\frac{\partial x_C}{\partial g} + g\frac{\partial x_G}{\partial g} > 0$.

Increasing gas generation costs g increase generation of renewables x_R.[6] Given a constant total power demand D, the effect on the residual demand DR is negative, i.e.,

$$\frac{\partial DR}{\partial g} = -\frac{\partial x_R}{\partial g} < 0. \tag{20}$$

Given a constant CO_2 cap E and applying the same proof as Lemmas 1 and 2 shows that $\tau > 0$. This **proves Lemma 3.**

Lemma 3 implies that decreasing gas generation costs g induce an exchange of one unit of a bundle of x_C and x_R for one unit of x_G, which is cheaper and equally CO_2 intensive. Vice versa, an increasing gas generation costs g imply an exchange of one unit of x_G for one unit of a bundle of x_C and x_R, which is more expensive and equally CO_2 intensive.

Summing up, a RES subsidy s that increases the gas price and therefore gas generation costs g has a positive cost effect since, besides the positive direct cost effect, both indirect effects are positive. However, if a RES subsidy s decreases the gas price and gas generation costs g, both indirect cost effects become negative such that they may overcompensate the direct cost effect. Hence, the overall effect of a subsidy s on power system costs K can become negative. This **proves Proposition 2**.

2.3. Graphical analysis

In the following, the effects of the stylized model are discussed in a graphical analysis. Therefore, Figure 1 illustrates the effects discussed before: The figure contains 10 diagrams numbered by roman numerals. Diagrams I to III show the relation between

[6] This theoretical model focuses on the long-run marginal costs. Therefore, an increasing gas price implies higher long-run marginal costs of gas-fired power plants. Thus, renewables become more competitive compared to gas-fired generation, and x_R increases.

subsidy s and quantities x_R, x_C and x_G, respectively. The blue lines illustrate the equilibrium (0), i.e., the reference case with $s = 0$. The variables x_C^0, x_G^0 and x_R^0 are the cost-efficient quantities. A subsidy would decrease x_G and increase x_R and x_C. Note that summing up $x_R(s)$, $x_C(s)$ and $x_G(s)$ horizontally would result in a vertical line, i.e., a subsidy would not affect power demand.

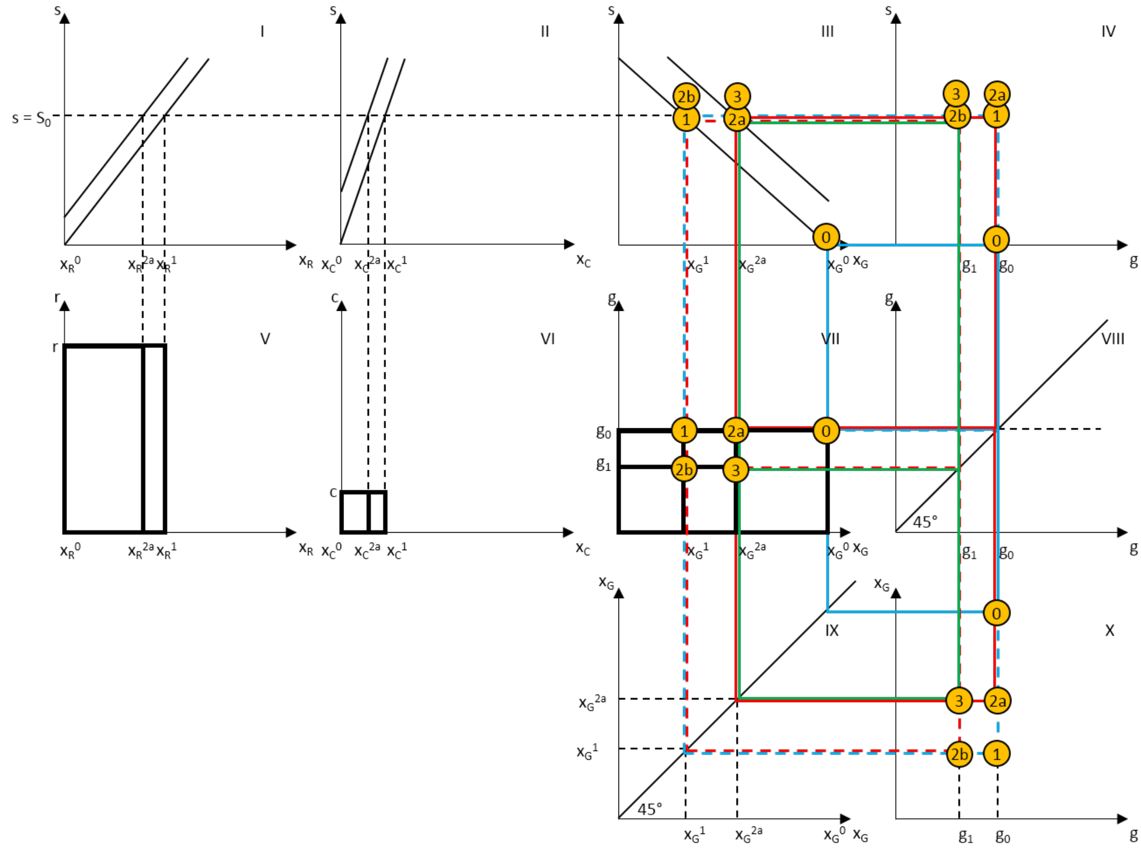

Figure 1: Effects of a fixed bonus RES subsidy on the power market, the gas market and power system costs

Assume a subsidy $s = S_0$ leads to a new equilibrium (1) with x_C^1, x_G^1 and x_R^1, illustrated by the blue dashed lines. Assume further that in this case, there is no interaction between the gas and the power market, i.e., $\frac{\partial x_G}{\partial g} = 0$ and $\frac{\partial g}{\partial s} = 0$. The latter is illustrated as a vertical line in Diagram IV. Diagrams V to VII illustrate the cost effects of changing subsidies. Since r and c are constant, the cost increases from coal and renewables are depicted by the respective rectangles in Diagrams V and VI. Since $x_G^1 < x_G^0$ and g_0 is assumed to be constant, the costs incurred by gas consumption decrease. However, the overall cost effect (direct cost effect) is positive for the reasons discussed in Section 2.1.

Assume next a case (2a) in which the power market interacts with the gas market but gas prices are still constant, i.e., $\frac{\partial x_G}{\partial g} < 0$ and $\frac{\partial g}{\partial s} = 0$ (illustrated by the red solid lines). The gas market equilibrium is given by a price leading to generation costs of g_0 and a quantity x_G^{2a}. This situation can occur if, for example, the gas demand function of the power sector is inelastic or if the gas supply equals gas demand at that particular price. The relationship $x_G^{2a} > x_G^1$ and a constant g_0 results in an outwards shift of $x_G(s)$ in Diagram III. Accordingly, $x_R(s)$ and $x_C(s)$ shift inwards (since the sum of all three terms is constant). The new equilibrium quantities, x_G^{2a}, x_C^{2a} and x_R^{2a}, are located between the equilibrium quantities of case (1) and case (0). Therefore, the power system costs in case (2a) are lower than those in case (1) and higher than those in reference case (0). This situation illustrates what was referred to as the indirect quantity effect in Equation 19.

Assume next a case (2b) in which the gas price and gas generation costs g are affected by the subsidy, i.e., $\frac{\partial g}{\partial s} < 0$ but $\frac{\partial x_G}{\partial g} = 0$ (red dashed lines). Therefore, $x_G^{2b} = x_G^1$. The equilibrium gas price in case (2b) implies different gas generation costs denoted as g_1. Diagram VII illustrates the indirect price effect of Equation 19. Total costs are reduced compared to case (1) since each unit of gas costs less.

Case (3), illustrated by the green lines, assumes $\frac{\partial g}{\partial s} < 0$ and $\frac{\partial x_G}{\partial g} < 0$. This is the case that will most likely occur during the simulations in the numerical analysis. A subsidy S_0 leads to a direct quantity effect, which strictly increases costs. Since the gas demand function changes due to the subsidy, the gas market equilibrium changes. If $\frac{\partial g}{\partial s} < 0$, i.e., the subsidy s decreases the gas price and generation costs decrease from g_0 to g_1, the gas consumption of the power sector increases further (assume to $x_G^3 = x_G^{2a}$). The indirect quantity effect therefore reduces the cost increase incurred by the direct effect. However, both effects in sum are still positive. But, if the subsidy causes a sufficient decrease in the gas price, the indirect price effect can lead to a reduction of power system costs as a result of the subsidy.

Figure 2 illustrates the cost effects once more, assuming that a RES subsidy decreases gas prices. R^0, C^0 (additional costs) and G^0 (cost savings) are depicted by blue lining and represent the direct effect. The terms R^1, C^1 (cost savings) and G^1 (additional costs) represent the indirect quantity effect (red lines) and G^2 (cost savings) represents the indirect price effect (green lines). As previously discussed, $R^0+C^0+G^0+R^1+C^1+G^1 > 0$, i.e., the direct and indirect quantity effects increase power system costs. However, a sufficiently large G^2 can lead to a subsidy for renewables decreasing overall power system costs.

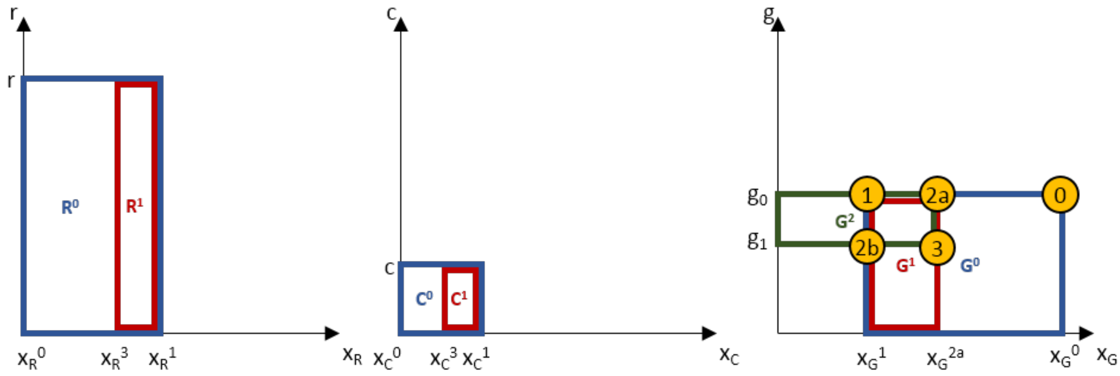

Figure 2: Cost effects of a fixed bonus RES subsidy

The magnitude of the effects discussed depend, among others, on the gas market reaction, i.e., how the subsidy affects gas demand and therefore the gas market equilibrium. If there is a high degree of supply-side market power in combination with a gas demand function that has become less elastic from the subsidy, the gas price may even increase as a result of the subsidy, i.e. $\frac{\partial g}{\partial s} > 0$. In that case, overall power system costs strictly increase.

This stylized model shows that the cost effects of subsidies (or similarly, of taxes) depend on the fuel switching characteristics of the respective electricity market. Therefore, I develop an integrated simulation model for both the power and the gas market in the next section.

3. Modeling the interaction of power and gas markets

This research aims at assessing the power system costs of climate policies combined with the EU-ETS, thereby accounting for the interactions between the electricity market and the oligopolistic gas market. Lienert and Lochner (2012) assess the importance of modeling the interdependencies between the power and gas market. In doing so, they develop a linear simulation model combining two LP models: a dispatch and investment power market model and a gas infrastructure model.[7] Abada (2012) develops a gas market MCP model that is able to simulate market power and incorporate demand functions accounting for fuel substitution. Although this approach implicitly models fuel substitution in the power sector, the author does not explicitly model the electricity sector. In a recent paper by Huppmann and Egging (2014), the authors develop a

[7] See Lienert and Lochner (2012) for a detailed overview of this branch of literature.

MCP model that integrates different fuel markets (e.g., gas, coal, oil) as well as fuel transformation such as the electricity sector. Fuel suppliers exert market power against exogenous linear demand functions of energy end users such as the industry, residential or transport sectors. However, fuel producers do not exert market power on the electricity sector. A common modeling approach seen in the literature on climate policy is the use of computed general equilibrium models (CGE). This class of models seeks to derive a Walrasian equilibrium of different sectors of an economy, which are represented by demand and supply functions. Obviously, CGE could be one possible method of modeling the interactions between the gas and power market.

However, the paper at hand develops a different methodology by combining a linear European electricity market model with a MCP global gas market model accounting for strategic gas producers. Both aspects enable a highly detailed and therefore more realistic representation of the respective markets as discussed below and in Sections 3.1 and 3.2.

The model developed in the following accounts for the interdependency of gas and electricity markets in an integrated framework and is suited to i) conduct long-term simulations of dispatch and investment decisions in the electricity market, ii) derive annual gas demand functions of the power sector and iii) simulate market power in the gas market.

Electricity markets are often modeled as linear cost minimization models (see Figure 3), an approach which implicitly assumes a perfectly competitive electricity market. LP electricity market models, such as the DIMENSION model (Richter (2011)) applied in this analysis (see Section 3.1), derive the cost-minimal amount of power plant dispatch and investment, from which additional information such as fuel demand or CO_2 emissions can be computed. Because of the high level of detail and to limit model complexity, many power market models are partial equilibrium model, i.e., the interactions with other markets are not modeled. Gas prices, for example, are exogenous inputs into the model. Gas demand from the power sector is a model outcome but does not have feedback effects on the gas market or gas prices.

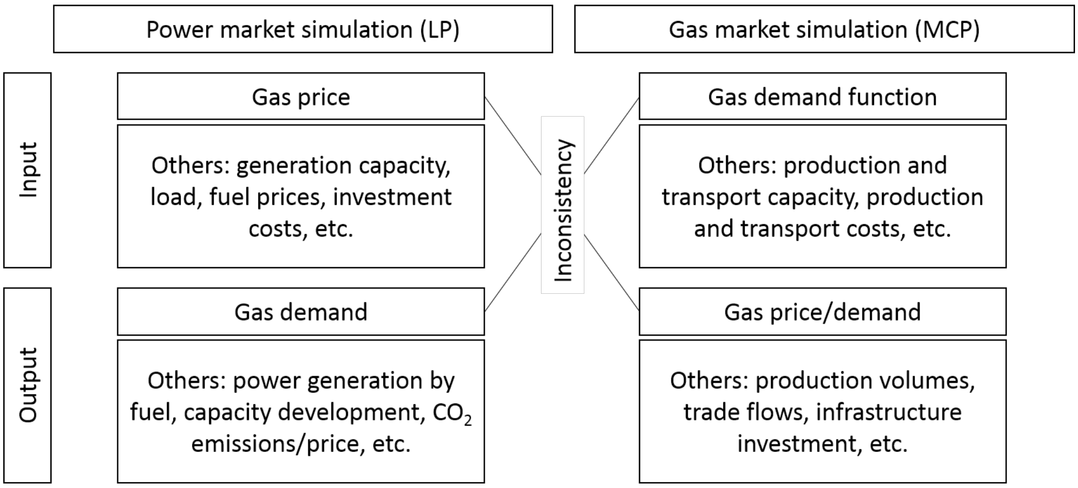

Figure 3: Inconsistencies of partial analytical electricity and gas market models

A common approach to model resource markets (and global gas markets in particular) are partial equilibrium models formulated as mixed complementarity problems (MCP).[8] MCP models, like the COLUMBUS gas market model applied in this analysis (see Section 3.2), allow for the simulation of strategic behavior of oligopolistic gas exporters. This requires the representation of the demand side such as, e.g., gas demand by the electricity sector using the inverse demand functions in an analytical form. The specification of the demand function is exogenous to the model. Often, demand functions are derived from historical or, for the future, from assumed price/demand combinations plus an assumption about the demand elasticity. The model outcome is a gas market equilibrium of production volumes, trade flows, demand and prices. However, since the demand functions are exogenous to the model, the model does not account for any interaction with other markets such as the electricity market.

Consequently, with respect to the research question, both models used standalone would yield inconsistent results (see Figure 3). Therefore, I present a new approach to integrate both models. Since natural gas is an input factor for power production, or vice versa the power sector is an end consumer of natural gas, the core idea is to link both market simulations by the demand functions. The demand functions represent the end users' (i.e., the power generators') demand for natural gas. A four-step procedure links both market models consistently (see Figure 4):

1.) Create n random samples of gas prices and run the DIMENSION electricity market model for each sample. Each simulation yields annual gas demands.

[8] See, for example, Trüby and Paulus (2012) for steam coal, Trüby (2013) for coking coal, Hecking and Panke (2014) for the interaction of iron ore and coking coal or Gabriel et al. (2005) for natural gas.

2.) Use the derived price/demand samples to approximate annual inverse demand functions $p(x)$ in an analytical form. The resulting demand functions are therefore outputs of the power market model.

3.) Use the demand functions as inputs of the COLUMBUS gas market model to derive the oligopolistic gas market equilibrium.

4.) Use the gas market equilibrium prices as inputs of the DIMENSION model and derive the power market outcome.

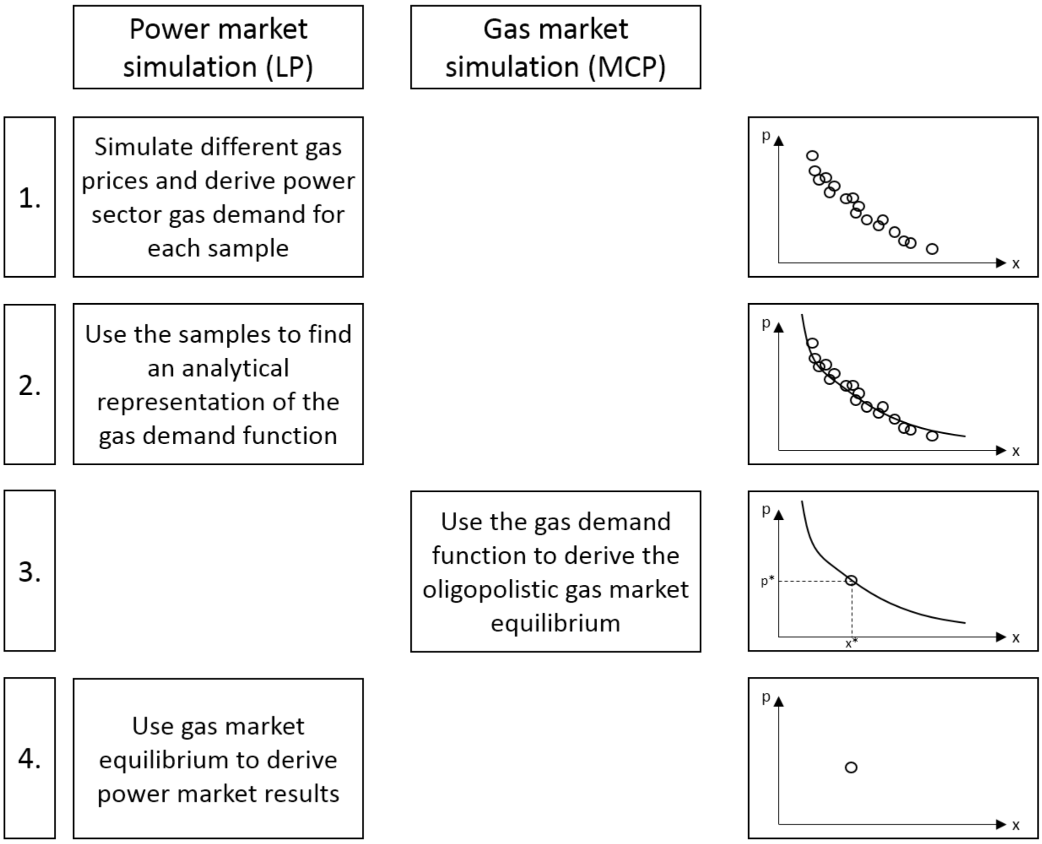

Figure 4: Integration of LP power market and MCP gas market model

In the following, the simulation models DIMENSION and COLUMBUS as well as the model integration approach are explained in greater detail.

3.1. The linear electricity market model DIMENSION

The linear electricity market model DIMENSION[9], developed by the Institute of Energy Economics at the University of Cologne, is designed for long-term analyses of the

[9] For a detailed model description, see Richter (2011) or Jägemann et al. (2013).

European power system up to 2050. As such, DIMENSION and its predecessor DIME have been backtested and applied in numerous long-term power market studies both in research (see, e.g., Hagspiel et al. (2014)) and policy advising (see, e.g., Fürsch et al. (2011)).

The model minimizes power system costs by deriving the cost-optimal power plant dispatch and investment. The power system can be subdivided into different geographical units such as countries, which are connected by net transfer capacities. Assumptions on annual power demand are broken down to hourly load patterns of typical days differentiated by, e.g., weekend/weekday or summer/winter. The hourly load is assumed to be inelastic and has to be met by the supply side, i.e., by conventional power plants and renewables. The hourly feed-in of renewables with zero variable costs such as wind or solar PV is exogenous to the model and also derived from typical days. The dispatch of conventional power plants is endogenous to the model and depends on the variable costs, flexibility and capacity of the power plants. The initial capacity of the generating units is exogenous to the model, but the model endogenously optimises investment in new power plants and renewables, depending on investment costs, future power plant utilization rates and a discount factor.

The DIMENSION model is a useful tool to simulate the effects of different power market policies in long-term analyses. The EU-ETS, for example, can be modeled by setting annual CO_2 boundaries. If such a boundary is binding, CO_2 allowances are scarce, which fosters power generation by more expensive but less CO_2-intensive power plants. A coal tax can be modeled by increasing the exogenously given coal price, and a fixed RES bonus can be modeled by reduced or negative variable costs of renewables. For each parameterization, the model yields the cost-optimal power plant dispatch and investment decisions, from which other information such as the annual gas demand can be derived.

3.2. The MCP gas market model COLUMBUS

The MCP gas market model COLUMBUS[10] simulates the global gas market up to 2040. It has been backtested with historic market outcomes in Growitsch et al. (2013). The model represents the spatial structure of worldwide supply, infrastructure and demand by a node-edge topology. COLUMBUS derives a market equilibrium by optimizing the dispatch and investment decisions of several gas market actors such as exporters, traders or operators of LNG infrastructure or pipelines. Initial production and infrastructure

[10] For a detailed model description, see Hecking and Panke (2012) or Growitsch et al. (2013).

capacities as well as cost parameters are inputs into the model. Actors can, however, also invest in production and infrastructure at certain investment costs. Concerning the demand side, the model distinguishes all important demand countries by sector (power, industry, residential), each represented by annual inverse demand functions. In the basic COLUMBUS version, demand functions are exogenously defined by historical or, for the future, by assumed price/demand combinations and assumed price elasticities.

COLUMBUS enables the simulation of Cournot behavior of gas exporters, i.e., the simulation of a spatial oligopoly. Modeling a Cournot oligopoly in a MCP requires an analytical representation of the price reaction towards changing output. The functions are common knowledge to all modeled Cournot players. In order to integrate the DIMENSION power market model with COLUMBUS, the annual inverse demand functions of the power sector are derived by DIMENSION and used in COLUMBUS. The details of this approach are presented in the next section.

3.3. Integrating power and gas market simulations

Since this study aims at assessing policies with respect to their long-term effects on power system costs up to 2040, the integrated simulation of electricity and gas market is conducted for the sample years 2015, 2020, 2030 and 2040.[11] Both DIMENSION and COLUMBUS are inter-temporal models that simulate the investment in power plants and gas assets, respectively. In particular, there is an important inter-temporal dependency between gas prices and power sector gas demand, illustrated in Figure 5: The gas prices p_i have a direct impact on the dispatch X_i, i.e., the gas consumption of gas-fired power plants. Additionally, the investment I_i in new gas-fired capacity depends not only on the future gas prices $p_{i',(i\leq i')}$ but also on the future utilization of gas-fired plants $X_{i,(i\leq i')}$. In turn, the utilization X_i depends on the past investments $I_{i',(i\geq i')}$.

[11] In order to avoid end effects, the simulation is continued until the year 2070. However, only the model results up to 2040 are important for this analysis.

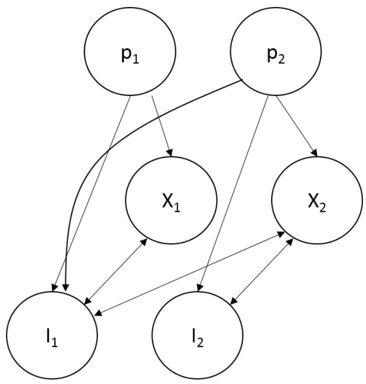

Figure 5: Inter-temporal dependency of gas prices and gas demand in the power sector

To limit complexity but to nonetheless cope with the inter-temporal dependency, the model implicitly assumes full gas price certainty in the power market. In other words, gas exporters play a one-shot Cournot game setting all quantities for future exports up to 2040. Power generators regard the resulting equilibrium gas prices as certain. This can be interpreted as a long-term gas contract or a forward purchase of gas. Besides certainty on gas prices, all players in the gas and the power market have perfect foresight on the future of both markets. In order to simulate the Cournot oligopoly in the gas market, the COLUMBUS model requires an inverse demand function that accounts for the hidden inter-temporal relation of gas prices and demand for discrete time steps:

$$\begin{gathered} f : \mathbb{R}^4 \to \mathbb{R}^4 \\ \begin{pmatrix} p_{2015} \\ p_{2020} \\ p_{2030} \\ p_{2040} \end{pmatrix} = f \begin{pmatrix} X_{2015} \\ X_{2020} \\ X_{2030} \\ X_{2040} \end{pmatrix}. \end{gathered} \tag{21}$$

3.3.1. Power market simulations of gas price samples

Due to the complex interactions between gas prices, investments in gas-fired power plants and gas demand, it is virtually impossible to trace the relation between prices and demand over time in an analytical functional form. Therefore, we simulate n gas price samples $(p_1, p_2, p_3, p_4)_{\{i, i \in 1 \dots n\}}$ derived from a uniform distribution of prices between 15 and 50 $\mathrm{EUR}_{2010}/\mathrm{MWh}_{\mathrm{th}}$. For each sample of gas prices, we run the DIMENSION model and derive a vector of annual amounts of gas consumption by the power sector $(X_1, X_2, X_3, X_4)_{\{i, i \in 1 \dots n\}}$. The resulting point cloud represents the hidden relation of gas prices and demands for the years 2015, 2020, 2030 and 2040, indexed by 1, 2, 3 and

4, respectively. In particular, it contains information on how the gas price in one year reacts to the changing output of a Cournot gas exporter in the same or a different year. The simulation of a gas market Cournot oligopoly requires the approximation of the point cloud by an analytical representation.

3.3.2. Deriving an inverse gas demand function

The COLUMBUS model requires a continuous and differentiable inverse demand function, as in Equation 21. The function consists of different additive components f_{ij}, representing the partial price effect of changing demand X_j on price p_i:

$$\begin{pmatrix} p_1 \\ p_2 \\ p_3 \\ p_4 \end{pmatrix} = f \begin{pmatrix} f_{11}(X_1) + f_{12}(X_2) + f_{13}(X_3) + f_{14}(X_4) \\ f_{21}(X_1) + f_{22}(X_2) + f_{23}(X_3) + f_{24}(X_4) \\ f_{31}(X_1) + f_{32}(X_2) + f_{33}(X_3) + f_{34}(X_4) \\ f_{41}(X_1) + f_{42}(X_2) + f_{43}(X_3) + f_{44}(X_4) \end{pmatrix}. \tag{22}$$

It is crucial to the consistency of model results that the inverse demand function has a high fit with the point cloud. Therefore, the point cloud is approximated by a function using a least-squares approach. A variety of test runs indicate that most of the variation in price p_j can be explained by the X_j of the same year j. This is economically intuitive since the power plant dispatch is strongly related to the fuel prices of the same time period. A low demand X_j therefore implies a high p_j. Unfortunately, a linear function does not properly represent the point cloud in most of the simulations. Among a variety of functional forms, the inverse tangens hyperbolicus, also used by Abada (2012) performs best in modeling the component f_{jj}. Furthermore, part of the price variation is also related to gas demands of other years: The demand $X_{j',(j \neq j')}$, representing the inter-temporal relation, also affects p_j because of power plant investment. I choose a linear function for each component $f_{jj',(j \neq j')}$.

This yields the following inverse demand function:[12]

$$\begin{pmatrix} p_1 \\ p_2 \\ p_3 \\ p_4 \end{pmatrix} = \begin{pmatrix} f_{11}(X_1) & + & \beta_{12}X_2 & + & \beta_{13}X_3 & + & \beta_{14}X_4 \\ \beta_{21}X_1 & + & f_{22}(X_2) & + & \beta_{23}X_3 & + & \beta_{24}X_4 \\ \beta_{31}X_1 & + & \beta_{32}X_2 & + & f_{33}(X_3) & + & \beta_{34}X_4 \\ \beta_{41}X_1 & + & \beta_{42}X_2 & + & \beta_{43}X_3 & + & f_{44}(X_4) \end{pmatrix} \tag{23}$$

with

$$f_{ii}(X_i) = \alpha_i + \frac{1}{\gamma_i}\,\mathrm{ath}(\frac{\delta_i - X_i}{\delta_i}) \tag{24}$$

and $\alpha_i, \beta_{ij}, \gamma_i, \delta_i$ as parameters. The parameter values are optimized in a non-linear problem with the objective of deriving the demand function that best fits the point cloud of samples. Therefore, the sum of squared deviations between modeled and sampled prices is minimized.

3.3.3. Implementing the inverse gas demand function in COLUMBUS

The inverse demand function is used to model a Cournot oligopoly in COLUMBUS. We assume that there are $k_{k\in K}$ oligopolistic gas exporters supplying a total of X_i in period i. The term x_i^k is the output of each player k and $C_i^k(x_i^k)$ is the respective cost function. Each player maximizes the following profit function for $i_{i\in 1\ldots 4}$ time periods:

$$\max_{x_i^k} \Pi_k = \sum_{i=1}^{4} p_i x_i^k - C_i^k(x_i^k), \text{ with } p_i = p_i(X_1, \ldots, X_4) \text{ and } X_i = \sum_{k\in K} x_i^k. \tag{25}$$

[12] Due to non-linearities, it is beyond the scope of this paper to focus on the mathematical details of the function. During the simulation, the derived function leads to consistent results for the gas and power market and has a good solvability using the PATH-solver in GAMS. Therefore the method of modeling the inter-temporal relations of gas prices and gas demand is used in this paper. Also, the inter-temporal approach is presented here since this topic has been hardly addressed in the literature thus far.

Taking the first derivative with respect to x_i^k yields the following first-order condition (FOC), with $\lambda_i^k(x_i^k)$ being marginal supply costs, i.e., the player-specific costs of transport, production and infrastructure scarcity rents:

$$\frac{\partial \Pi_k}{\partial x_i^k} = p_i + \sum_{j \in 1 \ldots 4} \frac{\partial p_j}{\partial x_i^k} x_i^k - \lambda_i^k(x_i^k). \tag{26}$$

Thus, the FOC takes into account the changing output x_i^k affecting the prices p_j of all time periods. For the specific inverse demand function used in this simulation (Equation 23), the following Karush-Kuhn-Tucker condition is implemented in the model:

$$-p_i - \frac{x_i^k}{\left(\frac{\delta_i - X_i}{\delta_i}\right)^2}\left(-\frac{1}{\gamma_i \delta_i}\right) - \sum_{i \neq j} \beta_{ji} x_i^k + \lambda_i^k(x_i^k) \geq 0 \quad \perp \quad x_i^k \geq 0. \tag{27}$$

Besides including the output decision of each player in COLUMBUS, it is necessary to include the inverse demand function. Two equations are required. The first one balances the firm-individual output x_i^k and the total output X_i. The total output can also be interpreted as total demand since in COLUMBUS total annual demand and supply have to be equal. Therefore, the dual variable is the price p_i,

$$\sum_i x_i^k = X_i \quad \perp \quad p_i \text{ free }. \tag{28}$$

The second equation balances the price variable p_i and the price function depending on $X_j, (j \in 1 \ldots 4)$. The dual variable is X_i,

$$p_i = \alpha_i + \frac{1}{\gamma_i} \operatorname{ath}\left(\frac{\delta_i - X_i}{\delta_i}\right) + \sum_{j, j \neq i} \beta_{ij} X_j \quad \perp \quad X_i \text{ free }. \tag{29}$$

3.3.4. Deriving the consistent market outcome

Running the COLUMBUS model using the inverse demand function derived from DIMENSION yields equilibrium gas prices $(p_1, p_2, p_3, p_4)^*$ and equilibrium gas demand $(X_1, X_2, X_3, X_4)^*$. The equilibrium gas prices are henceforth used as input fuel prices for the DIMENSION model. Running DIMENSION yields the total power sector gas demand $(\hat{X}_1, \hat{X}_2, \hat{X}_3, \hat{X}_4)$. The higher the fit between the gas demand from the COLUMBUS and the DIMENSION models, the more consistent the model results with respect to the interaction of gas and power markets will be. If the fit is insufficient, the procedure described in this chapter can be rerun with a higher level of detail, i.e., by simulating more samples (step 1) in a smaller price range around the equilibrium gas prices. If the fit is sufficient, the DIMENSION market outcome can be assumed to be consistent to the COLUMBUS outcome and model results such as the power system costs can be interpreted.[13]

4. Assumptions and scenarios

4.1. Assumptions on the numerical analysis

The numerical analysis is conducted with a special focus on 11 European countries[14] for the time range between 2013 and 2040. Whereas the COLUMBUS model, which accounts for the entire global gas market, is only run once per scenario, the electricity market model DIMENSION has to be run once for each gas price sample, i.e., 1000 times per scenario.[15] In order to reduce the complexity of DIMENSION and decrease computation time, the number of simulated countries is hence limited to 11. In total, these countries make up for 75 % of current CO_2 emissions of the European power sector and half of the current EU-ETS allowances. Since this study focuses on the power sector, other EU-ETS sectors such as cement production are not included in the modeling. Thus, this approach implicitly assumes the same marginal costs for the

[13] Appendix A provides an assessment of the convergence of the COLUMBUS and the DIMENSION models and shows how the outlined mechanism, i.e., simulating more samples in a smaller price range, improves the convergence of both models.

[14] These countries include Austria, Belgium, Czech Republic, Denmark, France, Germany, Great Britain, Italy, Poland, the Netherlands and Switzerland. The choice of these 11 countries was made because of their importance concerning European CO_2 emissions, their location in the center of Europe and their high gas market integration.

[15] The number of samples is set to 1000 in this analysis, with results achieving consistent results of gas and power market models.

proportional CO_2 reduction of other EU-ETS sectors. Although this is clearly a strong assumption, it does not qualitatively change the main messages of this analysis.

In this analysis, the DIMENSION model assumes an emissions quota of roughly 200 million CO_2 allowances for the power sector of the 11 countries in 2050, which equals a 80% CO_2 reduction compared to 2012. The number of allowances is reduced proportionately over time between 2012 and 2050. The analysis assumes implicitly that emissions certificates can be traded among those 11 countries. The quota must be achieved for each year, i.e., the possibility of "banking and borrowing" is excluded. In the basic configuration of this research, any other climate policy such as national RES subsidies or RES targets are, in contrast to the current regulation, not included in the simulation. Concerning the power plant and renewables data, this analysis uses the large-scale database of the Institute of Energy Economics at the University of Cologne, which contains information on ca. 4700 power plants – almost the entire European generation capacity including renewables. The database includes a variety of power plant parameters such as age, lifetime, efficiency, ramp-up times and current investment and operational costs. Concerning future investment costs, the assumption is made that the investment costs for mature technologies are constant, whereas costs decrease for new technologies such as certain renewables. Future investment costs are mainly based on IEA (2013).

Concerning fuel prices, this analysis is consistent with to the assumptions made in Fürsch et al. (2011), with the exception of gas prices which are modeled endogenously. In contrast, coal prices are exogenous to the model for three reasons: First, there is currently no dominant player active on the global thermal coal market. Thus, a polypolistic coal market can be assumed (see, e.g., Trüby and Paulus (2012) or Haftendorn and Holz (2010)). Second, whereas for many natural gas exporters the only sales opportunity is Europe via pipeline, coal trade via ship or train is much more flexible concerning the demand side. Third, due to the huge mining capacities in China (in particular), the global coal supply curve is rather flat. If European coal imports were to decline, traditional coal exporters such as Colombia or Russia could easily shift their exports to China or India, where they would crowd out domestic production. Although European coal prices would decrease after a demand drop, the price effect would be negligible compared to natural gas.

The gas market model COLUMBUS accounts for all major production and demand regions worldwide. The above-mentioned 11 countries are regarded as one demand region. Therefore, an implicit assumption is made that there is a full gas market integration among these countries, which is reasonable considering the well-built transport infrastructure, in particular, of the Northwest European gas market. The annual exogenous demand of these 11 countries, which is composed of the sectoral demand for power, heat and industry, is corrected for the power demand. The power demand is modeled by the demand functions derived through DIMENSION. The heat and industry gas demand functions are assumed to be exogenous. These assumptions as well as the future demand for other countries worldwide follow the WEO 2013 and MTGMR 2013. Parameters on existing infrastructure and production capacities are identical to those of Growitsch et al. (2013), in which the authors provide a calibration of the model based on historic data. Future production and infrastructure capacities are derived endogenously in the model. However, to account for political or geographical limitations or the resource endowment of supply countries, potential investment in production and infrastructure assets are limited, in line with the future projections of WEO 2013. Two assumptions are of particular importance for the degree of competition in Europe: First, potential LNG exports from the US and Canada amount to 60 bcm for 2020 and 200 bcm for 2040.[16] Second, gas trade from Iran and Iraq via Turkey to Europe is excluded.[17] More detailed information concerning model parameters of the DIMENSION and COLUMBUS models are provided in Appendix C.

4.2. Scenario design

To investigate the hypotheses H1 to H3, the paper at hand assesses three scenarios of different climate policy regimes in the European power sector. In the scenario "Reference", the only active carbon abatement policy is the EU-ETS. In particular and in contrast to the current real-world regulation, there are no additional RES subsidies such as national feed-in-tariffs in place. The scenario "Coal Tax (CT)" assumes the presence of a coal tax in addition to the EU-ETS. The coal tax is raised for each thermal megawatt-hour of hard coal burned to generate power. The tax is identical for each of the countries considered. A tax of 10 $\text{EUR}_{2010}/\text{MWh}_{\text{th}}$ and a tax of 20 $\text{EUR}_{2010}/\text{MWh}_{\text{th}}$ are simulated. The scenario "Fixed RES Bonus (FB)" assumes a fixed bonus subsidy that is paid to the operator of a renewable power plant for each megawatt-hour of electricity generated.

[16] The parameter "potential LNG exports" is an upper boundary on the capacity of LNG export terminals. Hence, this parameter does not necessarily match the exports derived by the model since the model could regard investment or LNG exports to be uneconomical. Furthermore, LNG exports from North America would not necessarily affect the European gas market, since they could also be attracted by Asian importers.

[17] Even though Iran and Iraq are endowed with substantial natural gas resources, future gas sales to Europe are highly uncertain due to the current political situation and the need for transport infrastructure.

The fixed bonus is independent of technology and location. Fixed bonus subsidies of 5, 10, 20 and 30 EUR_{2010}/MWh_{el} are simulated.

In order to examine hypothesis H4, each of the three scenarios is derived in an additional variant that assumes a different market structure of the gas market: In a fictitious case, I assume a cartel of Norway and Russia. Even though this assumption is not necessarily realistic from a gas market point of view, the sole purpose of this setting is to assess the effects of a higher degree of market power.

5. Results of the numerical analysis

The simulation results are discussed in four parts: First, I focus on the effects of climate policies on the power market gas demand functions and the resulting equilibrium gas prices. Secondly, the policy effects on power generation by fuel type are discussed. Thirdly, I compare the overall power system costs of the different scenarios with a special focus on the cost effects as discussed in Section 2.3. Fourth, I analyze the effects of changing gas market power on the power system costs.

5.1. Gas demand functions and equilibrium gas prices

Figure 6 shows the effects of renewable subsidies on gas demand functions for the years 2015, 2020, 2030 and 2040. "REF" labels reference scenario and "FB10" and "FB20" label a fixed bonus payment of 10 EUR_{2010}/MWh_{el} and 20 EUR_{2010}/MWh_{el}, respectively. The point clouds illustrate gas price/demand combinations simulated by the power market model DIMENSION. The black lines show the approximated demand functions.[18] The yellow square shows the equilibrium gas price/demand combination for the respective year and scenario resulting from the gas market simulation by the COLUMBUS model.

[18] Since the demand function for each scenario is four-dimensional, the dimensionality has to be reduced in order to show it graphically. For the year 2015, for example, the function drawn shows the relation between the gas price and the quantity of the year 2015. In this figure, the other quantities for the years 2020, 2030 and 2040 are set to the resulting gas market equilibrium quantities.

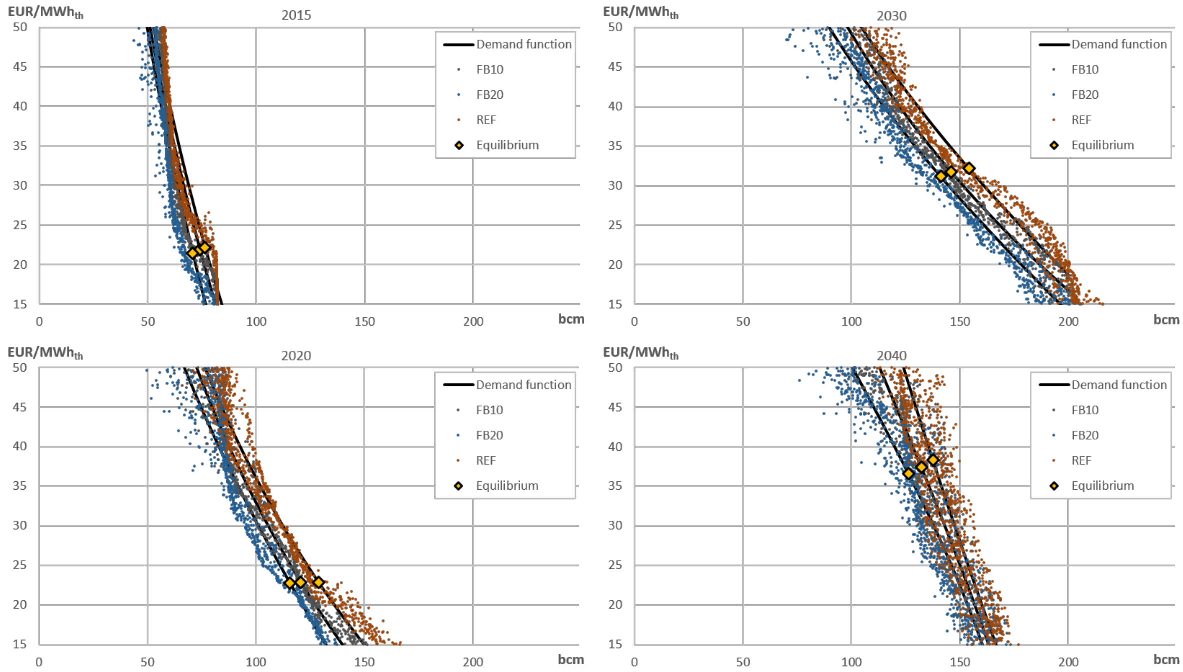

Figure 6: Gas price/demand samples, demand curves and gas market equilibria for the fixed bonus scenarios

The figure shows a similar effect for all four years. Increasing the renewable subsidy shifts the gas demand function inwards. In other words, increasing competition by cheaper renewables decreases the willingness-to-pay for natural gas of the power sector. The shift in the demand curve changes the resulting gas market equilibrium. An increasing fixed bonus for renewables increases the equilibrium gas demand and decreases gas prices. This effect is unambiguous for all subsidy scenarios and all years although the price decrease is very weak for the year 2020.

Figure 7 is identical to figure 6 but illustrates the effects of a coal tax on the gas demand functions and the resulting gas market equilibria. "CT10" and "CT20" label coal tax scenarios of 10 $\mathrm{EUR}_{2010}/\mathrm{MWh}_{\mathrm{th}}$ and 20 $\mathrm{EUR}_{2010}/\mathrm{MWh}_{\mathrm{th}}$, respectively. In particular for the years 2015 and 2020, fuel competition between coal and natural gas becomes more intensive because of the coal tax. For this reason, in CT10 and CT20, the power sector becomes very sensitive with regard to natural gas prices. Even though gas demand in equilibrium increases substantially, the gas price decreases. This can be explained by lower oligopoly markups of gas producers because of the less steep and more price elastic demand function induced by the coal tax. For the years 2030 and 2040 the elasticity is not affected as much. Thus, the gas market equilibria show that gas consumption and gas prices increase with the coal tax.

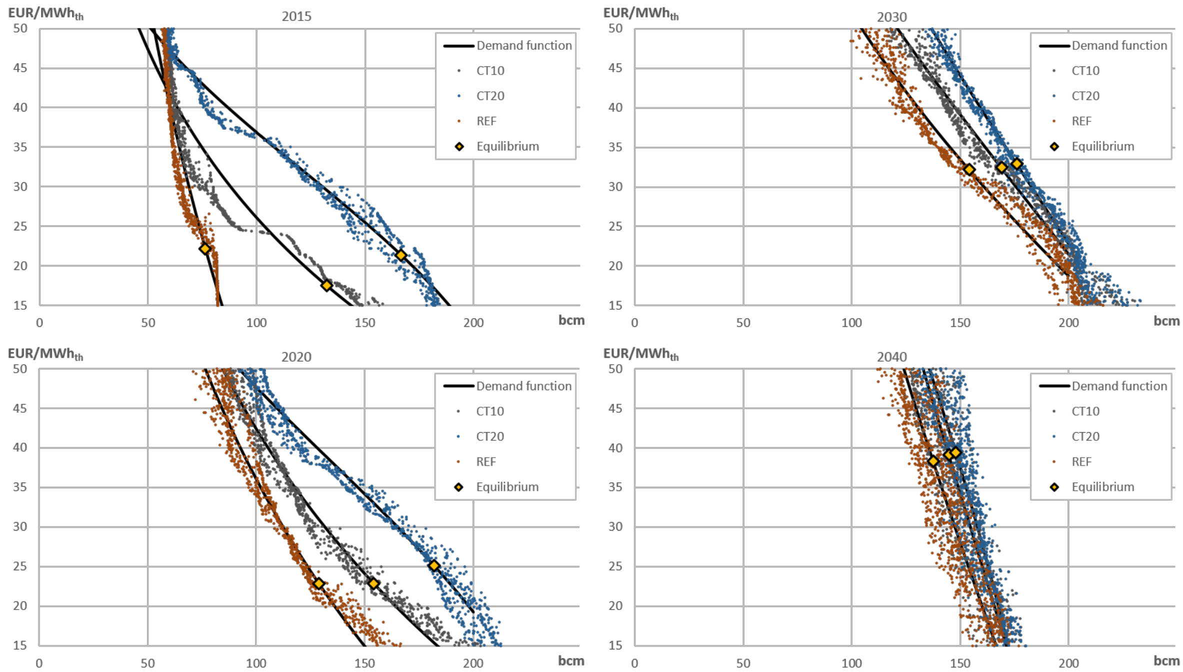

Figure 7: Gas price/demand samples, demand curves and gas market equilibria for coal tax scenarios

With regard to hypothesis H1, the results confirm the intuition that renewable subsidies cause a decrease in gas prices. Concerning the coal tax the picture is more diffuse. Although in 2030 and 2040 a coal tax causes an increase in gas prices, the example of the year 2015 has provided a valuable exception: If a policy significantly changes the gas demand elasticity, the resulting price effect can contradict to H1 because of the oligopolistic gas market structure.

5.2. Effects of climate policies on power generation

Figure 8 depicts the effects on power generation by fuel type when a fixed bonus of 20 EUR$_{2010}$/MWh$_{el}$ for renewables is introduced. As shown in Section 2, such a subsidy has both a direct effect (labeled "Dir.") and an indirect effect (labeled "Ind.") on power generation. The direct effect is derived by comparing the power generation of the Reference scenario $x_{REF}(g_{REF})$ with the power generation of the fixed RES Bonus scenario

(FB), but applying the equilibrium gas prices of the Reference scenario ($x_{FB20}(g_{REF})$). Thus,

$$x_{dir} = x_{FB20}(g_{REF}) - x_{REF}(g_{REF}). \tag{30}$$

The indirect effect, which is induced by a changing gas market price, is derived by comparing $x_{FB20}(g_{REF})$ to $x_{FB20}(g_{FB20})$. Thus,

$$x_{ind} = x_{FB20}(g_{FB20}) - x_{FB20}(g_{REF}). \tag{31}$$

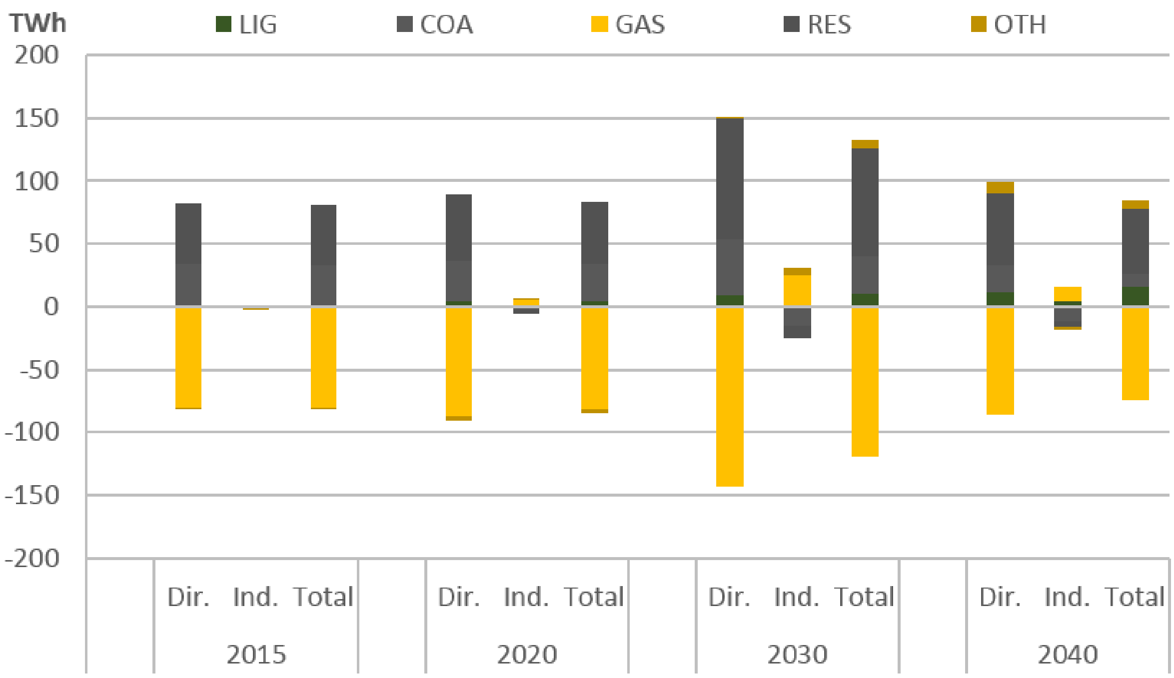

Figure 8: Effects of a fixed RES bonus on power generation by fuel type

As expected from the stylized model described in Section 2, the direct effect of a subsidy under the EU-ETS is an increasing generation of renewables and cheap, but CO_2-intensive, coal and lignite. Gas-fired generation decreases. As discussed in Section 5.1, gas prices in equilibrium decrease when a subsidy is introduced. Therefore, the indirect effect of a subsidy via the gas price is an increasing gas-fired generation, whereas generation from renewables, coal and lignite decreases. However, the overall effect is a decreasing gas-fired generation.

Figure 9 illustrates the effects of a 10 EUR_{2010}/MWh_{th} coal tax on power generation. The direct effect of a coal tax is a fuel switch from coal to gas. It can be observed that renewable generation also decreases, for example in 2020. Since coal-fired generation is replaced by gas, the CO_2 emissions price decreases, which causes gas to replace renewable generation. The indirect quantity effect is in line with the observations of Section 5.1. In 2015, the decreasing gas price leads to another increase in gas-fired generation. From 2020 onwards, the indirect effect is very weak because of the low price effect (2020, 2030) and the low demand elasticity (2040).

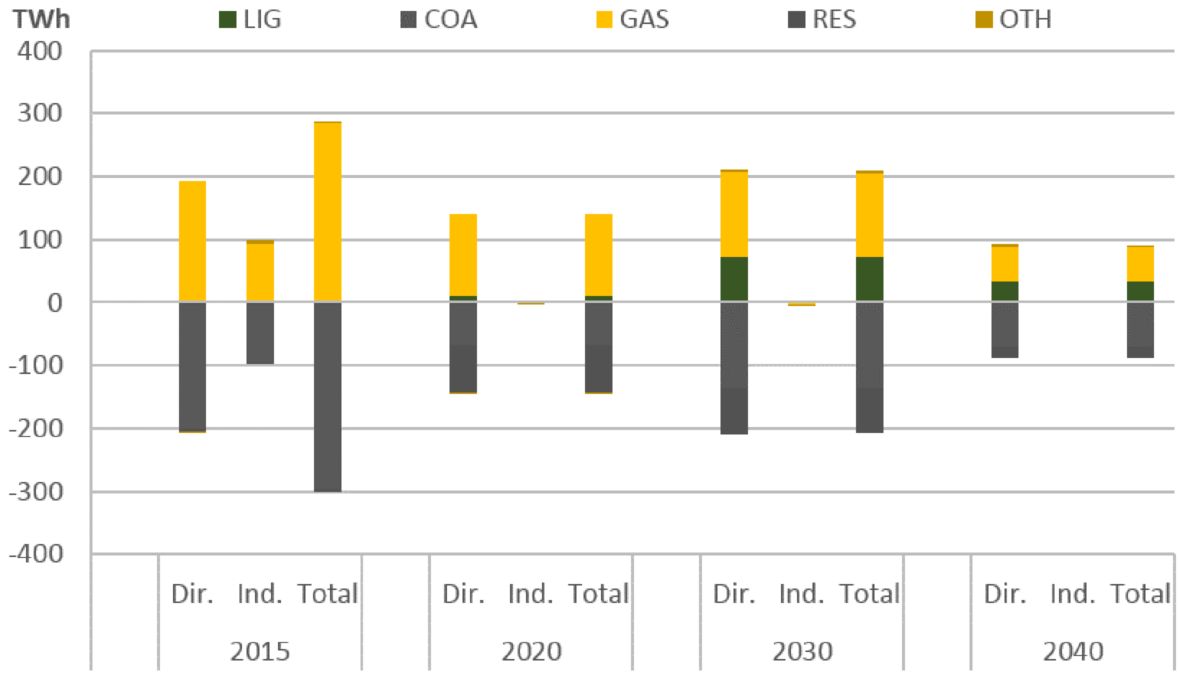

Figure 9: Effects of a coal tax on power generation by fuel type

5.3. Power system cost effects of climate policies

The power system costs are defined as the relevant costs for dispatch and investment decisions, i.e., fuel costs, fixed operation and maintenance costs and investment costs for new power plants. Subsidy expenses are added to the costs, and tax revenues are subtracted. In this analysis, the costs are summed up for the time range between 2013 and 2040 at a discount rate of 10%.[19]

Figure 10 illustrates the cost effects of the fixed bonus RES subsidy and coal tax scenarios. As shown in Section 2, the cost difference between the two scenarios can be subdivided into a direct quantity effect (C_{dir}), an indirect quantity effect (C^q_{ind}) and an

[19] Clearly, the discount rate is crucial for results of the numerical simulation in Section 5. Although the assumed discount rate affects the magnitude of the simulation results, the effects derived in Section 2 remain qualitatively the same. To provide the reader some insight on the sensitivity of the discount rate on the simulation results, Appendix B presents an analysis assuming a discount rate of 3%.

indirect price effect (C^p_{ind}). In the example of the scenario FB20, the direct quantity effect is derived by comparing the costs of scenario FB20 with the Reference scenario, with both scenarios assuming the gas price of the Reference scenario, g_{REF}:

$$C_{dir} = C_{FB20}(g_{REF}) - C_{REF}(g_{REF}). \tag{32}$$

The sum of the indirect quantity effect and the indirect price effect is derived by comparing the costs of the FB20 scenario using the price of the Reference scenario, $C_{FB20}(g_{REF})$, to the costs of the FB20 scenario using the gas price of the FB20 scenario, $C_{FB20}(g_{FB20})$. Thus,

$$C^x_{ind} + C^p_{ind} = C_{FB20}(g_{FB20}) - C_{FB20}(g_{REF}). \tag{33}$$

The indirect price effect is derived as the gas price difference between scenario FB20 and the Reference scenario multiplied by the gas consumption of the power sector in the FB20 scenario, x^{FB20}_G:

$$C^p_{ind} = (g_{FB20} - g_{REF})x^{FB20}_G. \tag{34}$$

As discussed in the previous section a coal tax in the power sector causes a deviation from the cost efficient power generation under the no-tax case. Hence, the direct cost effect of a coal tax is positive, as Figure 10 illustrates. In the CT10 scenario, where a coal tax causes gas prices to both increase and decrease (depending on the year), the indirect quantity effect is positive. In other words, changing gas prices forces power generation to deviate from the cost-optimal generation even more than seen in the direct effect. However, the costs of gas purchases decrease, i.e., the indirect price effect reduces costs. Yet, in total, power system costs in the CT10 scenario are higher than in the reference case. In the CT20 scenario, except for the year 2015, gas prices increase. Therefore, a higher gas price increases the costs of gas purchased by the power sector, i.e., the indirect price effect is positive. Hence, these numerical results confirm hypothesis H2: A coal tax increases overall power system costs.

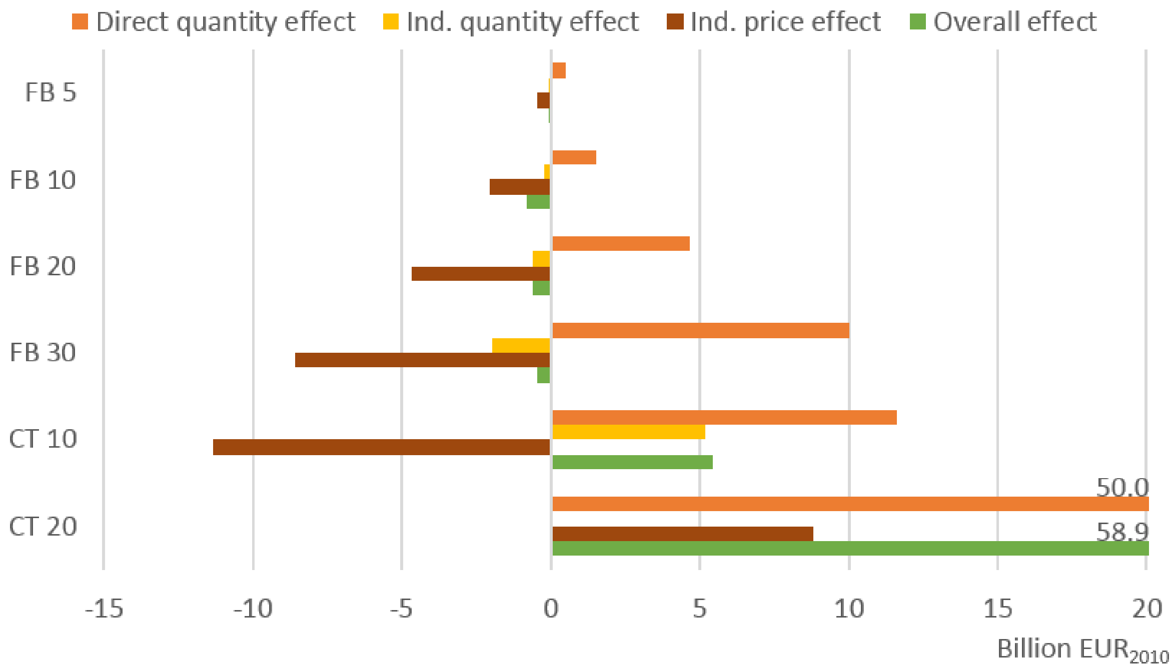

Figure 10: Power system cost effects of different levels of coal taxes and RES subsidies

With regard to fixed bonus RES subsidies, Figure 10 reveals that the direct cost effect of such a subsidy is positive and increases with the subsidy. However, since the subsidy causes the gas price to decrease, the indirect quantity effect reduces the additional costs incurred by the direct quantity effect. Nonetheless, the sum of both the direct and indirect quantity effect is positive. However, the indirect price effect of a subsidy, i.e., decreasing costs of gas purchased by the power sector, overcompensates the quantity effects. Therefore, this numerical simulation of the European power and gas market confirms hypothesis H3: A fixed bonus RES subsidy may decrease overall power system costs because of the gas price reaction.

5.4. Cost effects of supply side concentration on the gas market

A higher supply side concentration on the gas market is simulated by a fictitious cartel of Norway and Russia. For the scenarios FB20 and the CT10, Figure 11 compares the gas price reaction (i.e., the price differences to the respective REF scenario) under the standard gas market structure (STANDARD) with the cartel (CARTEL).[20] The gas price reduction in the FB20 scenario is higher in the case of the cartel than in the standard case for each year. In the Coal Tax scenario CT10, the gas price reduction in

[20] For the other scenarios, the results are qualitatively the same.

the cartel case is lower in 2015 than in the standard case, whereas the gas price increase in the years 2020 and 2030 is higher.

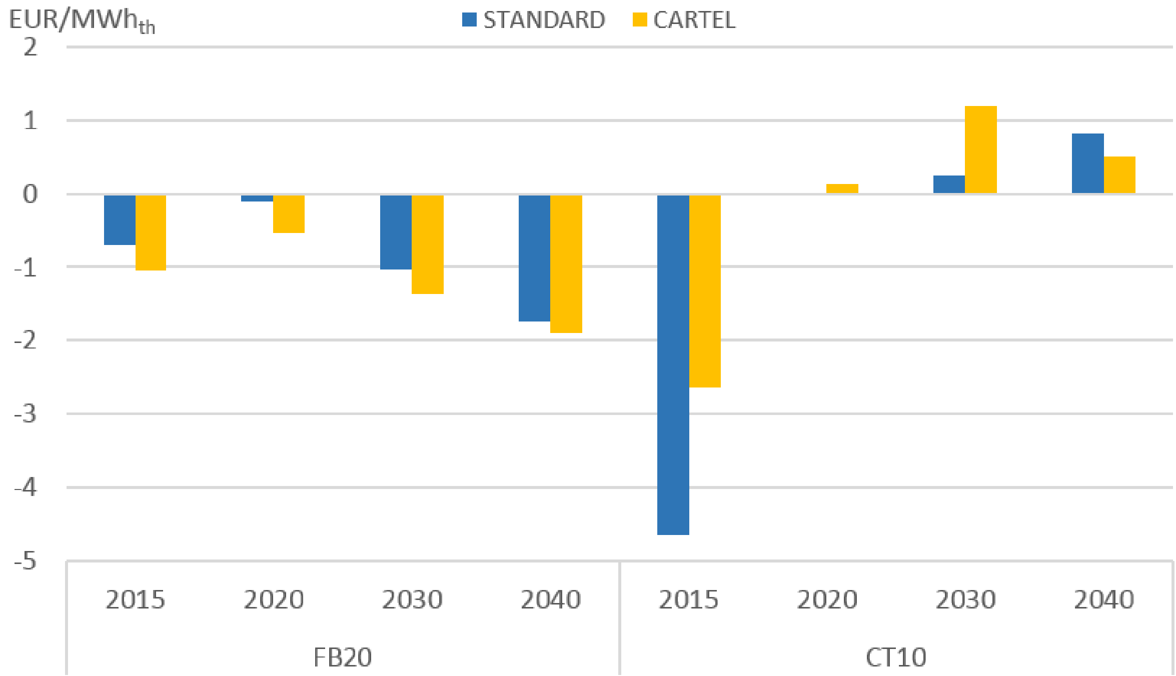

Figure 11: Gas price effects of different policies under different gas supply-side market structures

These price reactions explain the cost effects when different gas supply-side structures are assumed (see Figure 12). In the RES subsidy scenarios, the higher price decrease causes a higher indirect price effect such that the overall power system cost reduction is higher in the CARTEL case than in the STANDARD case. In the coal tax scenarios, the opposite holds. To sum up, with regard to hypothesis H4, a higher market power in the gas market amplifies the discussed effects.

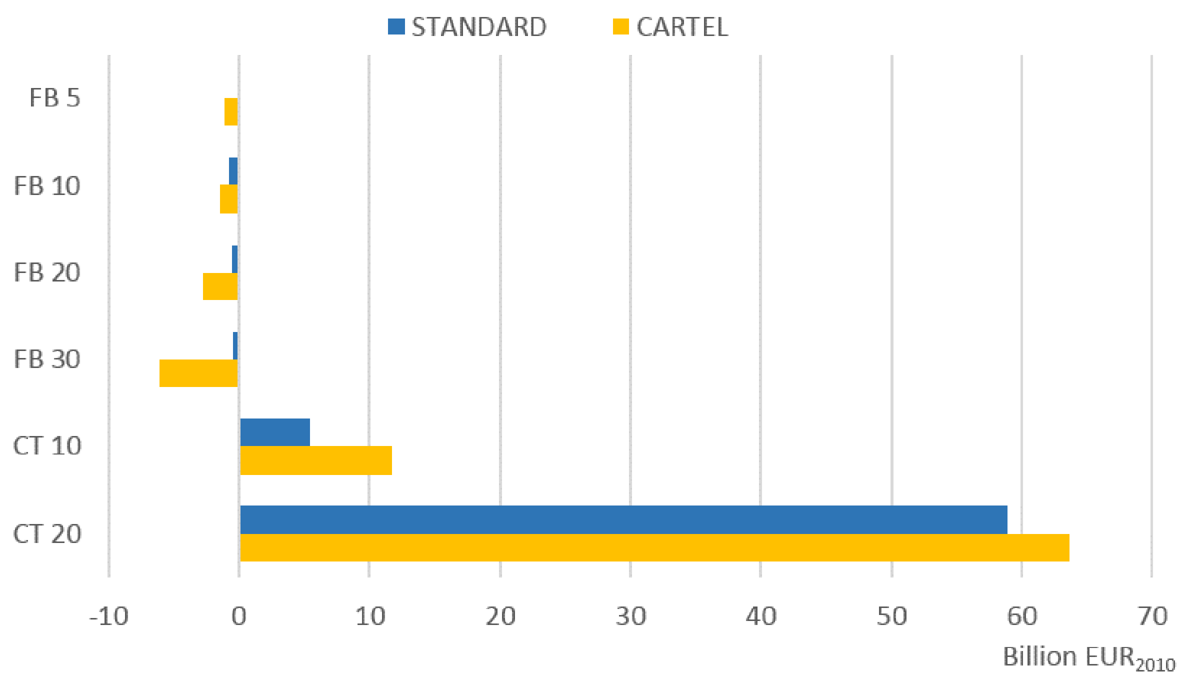

Figure 12: Effects of higher market power of gas suppliers on power system costs

6. Conclusion

The paper at hand has discussed how a coal tax and a fixed bonus RES subsidy in combination with a CO_2 emissions quota affects power system costs. Since climate policies influence gas demand of the power sector and hence, gas prices, this research explicitly accounts for the interactions between the power and the gas market. In a stylized theoretical model using the example of a fixed bonus RES subsidy, I have identified three effects of the subsidy on power system costs. First, a subsidy directly affects power generation by fuel type and therefore system costs (*direct effect*). Second, since the subsidy affects gas prices, it also affects power generation by fuel type via the gas price, an effect referred to as the *indirect quantity effect*. The subsidy affecting gas prices also causes an *indirect price effect*, i.e., changing gas prices affect the purchase costs per unit of natural gas consumed by the power sector.

Applying a numerical simulation model and integrating the power and gas market in a case study for 11 relevant European countries, I draw 4 main findings. First, a coal tax influences gas prices ambiguously, depending on the effect of a coal tax on gas demand elasticity. On the contrary, a fixed bonus RES subsidy decreases gas prices for each of the simulated subsidy levels. Second, a coal tax results in tax distortions, i.e., it increases power system costs even at constant gas prices (direct effect). Since a coal tax affects gas prices ambiguously, the overall power system costs increase, even when accounting for the indirect quantity and price effects. Third, the simulation results reveal that a fixed bonus RES subsidy can decrease overall power system costs: On the one hand, the subsidy increases costs given fixed gas prices (direct effect); yet, on the other hand, the subsidy decreases gas prices such that the indirect quantity and price effects overcompensate the direct effect. Fourth, when a higher level of market power of gas suppliers is assumed, the overall effect of higher market power on power system costs is amplified. Concerning a coal tax, the simulation results show that a higher degree of market power further increases costs, whereas, concerning a RES subsidy, it further decreases costs. The assumed discount rate of future costs has proven to be a crucial parameter, which affects these results quantitatively, however not qualitatively.

This analysis has focused solely on the effects of climate policies on the *power system costs* of 11 select European countries. In particular, decreasing power system costs through a fixed RES bonus do *not* imply that this subsidy makes CO_2 abatement more efficient. The reason for decreasing power system costs are the decreasing expenditures of power utilities for the gas purchased, which come at the disadvantage of gas suppliers, whose revenues decline. In other words, introducing the subsidy redistributes welfare from players in the gas market to players or end consumers in the power market, as well as to suppliers of coal or renewable technologies. Even though the discussed subsidy would cause an inefficient allocation of primary energy use in the power sector and, hence, higher CO_2 abatement costs, European policy makers could have a sound motivation to establish a fixed RES bonus subsidy: in order to redistribute welfare from the most important gas suppliers such as Russia, Norway, Algeria or Qatar to market participants of the European power market, i.e., power producers or end users.

This research has pointed out that the evaluation of climate policies in the power sector should take into account the upstream markets and their market structure. The main focus was a discussion of the power system cost effects of climate policies in due consideration of the interdependencies of the power and gas market. Yet, it is important to stress that this study does not provide a comprehensive assessment of climate policies, for several reasons. First, the sole objective of this study is to determine the minimal power system costs. Regarding the coal tax, the tax could aim at further objectives other than efficient CO_2 abatement. Other policy objectives could justify higher costs from a coal tax. Second, this research only assesses two policies and simulates a setting in which there are no other climate policies in place. In reality, there is a variety of (national) climate policies which could affect gas prices differently or interact with other policies. In particular, the study does *not* say that the current regime of national technology-specific RES subsidies decreases power system costs. Third, even though the study reveals cost reduction potentials of a technology-neutral and location-neutral RES subsidy, it remains an open question whether there may be another policy regime that further decreases gas prices and, therefore, power system costs. As such, an EU energy union is often discussed as a mean to decrease gas purchasing costs. However, the main flaw of such a measure, the threat of downstream cartelization, is avoided by a RES subsidy. Fourth, the dynamic effects of climate policies, such as a higher or lower technological progress because of a subsidy, are not investigated in this research. Fifth, efficiency gains and losses in other related markets such as the gas, coal or renewables market have not been assessed. All of the five outlined aspects could motivate interesting extensions to this paper.

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A. Convergence of the power and the gas market model

In order to assess the convergence of the power market model and the gas market model, equilibrium gas prices and gas demand of both models are compared in this section. Since the equilibrium gas prices of the gas market model are used as an input to the power market model, gas prices are identical in both models. Therefore, the convergence of both models is assessed by comparing the equilibrium gas demand of the power market model and the gas market model.

Table A lists the deviation of gas demands of both models for different scenarios. The deviation d is derived as follows: $d = \frac{x_{dim}}{x_{col}} - 1$, with x_{dim} being the equilibrium gas demand derived by the DIMENSION model and x_{col} being the equilibrium gas demand derived by the COLUMBUS model. The worst convergence of both models is observed for the years 2015 and 2020 and the scenarios FB20 and FB30 with deviations of up to 10%.

Table 1: Deviation of gas demands between power market model and gas market model with different price ranges

Scenario	**2015**	**2020**	**2030**	**2040**
REF	5%	-2%	-1%	0%
FB5	3%	-1%	-2%	1%
FB10	0%	-1%	-2%	1%
FB20	-5%	-3%	-4%	1%
FB30	-5%	-10%	-7%	3%
CT10	5%	-2%	3%	1%
CT20	5%	2%	1%	-1%

One approach to improve the consistency of both models could be to use a different functional shape of the inverse demand function for a certain year, e.g., a hyperbolic function. Another approach could be to focus the range of gas price samples to a smaller interval, i.e., increasing the fit in the region of prices that were relevant during the gas price simulation. Consequently, instead of sampling gas prices between 15 and 50 EUR_{2010}/MWh_{th} for all years, I limit the price range to 15 to 25 EUR_{2010}/MWh_{th} for the year 2015, to 20 to 30 EUR_{2010}/MWh_{th} for the year 2020 and to 25 to 40 EUR_{2010}/MWh_{th} for the years 2030 and 2040. The gas demand function is estimated once more based on the restricted set of samples, and new equilibria of both models are derived. Table A lists the resulting gas demand deviations between both models. The results reveal that the outlined approach has improved the convergence of both models. The results of the numerical analysis change slightly, but are generally robust to this approach. In particular, none of the main messages of this study is affected qualitatively.

Table 2: Deviation of gas demands between power market model and gas market model with a limited price range

Scenario	**2015**	**2020**	**2030**	**2040**
REF	0%	-2%	-1%	0%
FB5	-1%	0%	-1%	0%
FB10	-3%	0%	0%	-2%
FB20	-2%	1%	-2%	-2%
FB30	-2%	-2%	-3%	1%
CT10	-1%	0%	2%	-1%
CT20	2%	1%	0%	-1%

B. Sensitivity analysis of the discount rate

The following section of the Appendix analyses, how a discount rate of 3% instead of 10% affects the model results. First, Figure 13 illustrates the gas price/demand samples for two Fixed Bonus scenarios given a 3% discount rate. Note that the samples spread out more than the samples for which a 10% discount rate is assumed (see Figure 6). Thus, the inter-temporal components of the demand function have a higher relevance the lower the discount rate gets. This finding does not surprise, since future costs have a higher weight if a lower discount rate is assumed. This also explains why gas prices and gas demand are c.p. lower given a 3% discount rate instead of a 10% discount rate. Assuming a lower discount rate lets renewables become more competitive since future fuel costs of, e.g., natural gas have a higher impact on generation costs.

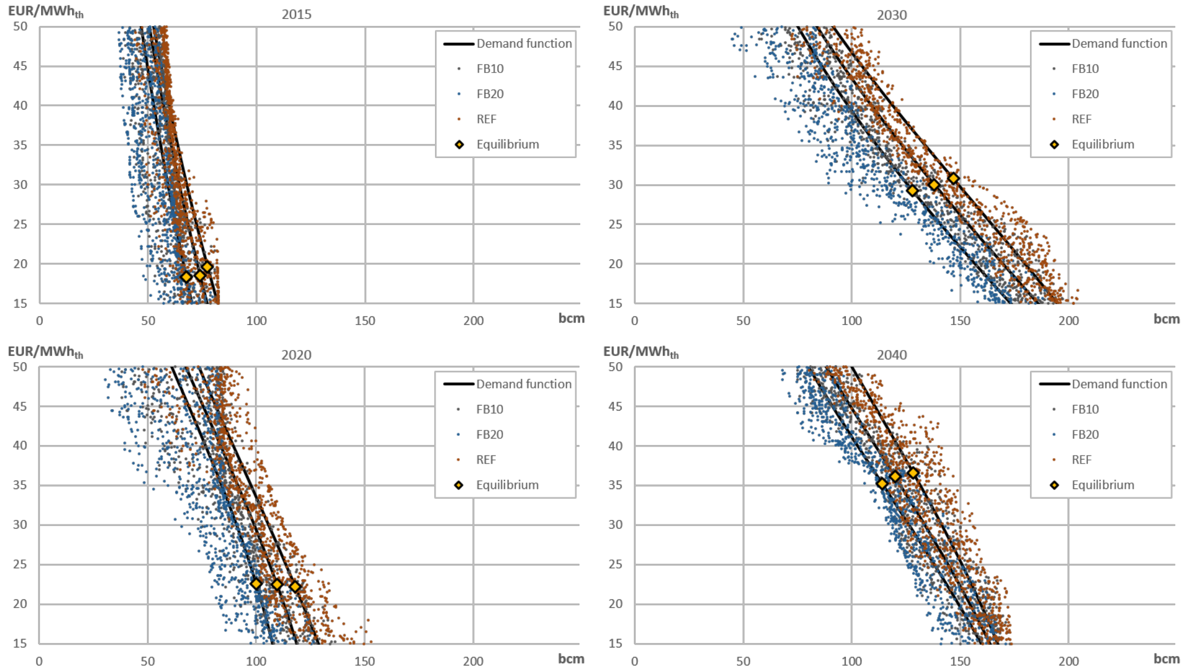

Figure 13: Gas price/demand samples, demand curves and gas market equilibria for the Fixed Bonus scenarios at a discount rate of 3%

Figure 14 depicts the cost effects of the Fixed Bonus and Coal Tax scenarios when assuming a discount rate 3%. Similar effects as in the 10% discount rate case can be observed, i.e., the overall cost effect of a coal tax is positive and (except for the FB30 scenario) it is negative for the Fixed Bonus scenarios. However, effects strongly differ in magnitude due to the lower discount rate of 3%.

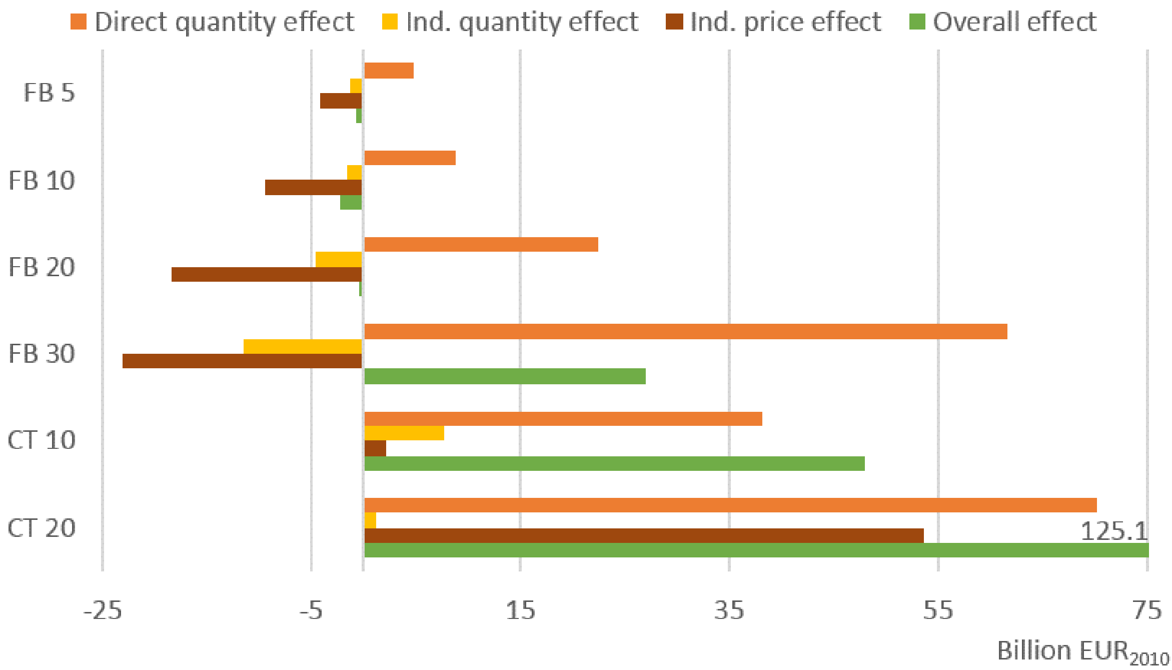

Figure 14: Power system cost effects of different levels of coal taxes and RES subsidies at a discount rate of 3%

C. Data

Table 3: Fuel costs for power generation

EUR_{2010}/MWh_{th}	**2015**	**2020**	**2030**	**2040**
Nuclear	3.5	3.3	3.3	3.3
Lignite	1.4	1.4	2.7	2.7
Coal	9.1	10.1	10.9	11.9
Oil	42.5	47.6	58.0	69.0

Table 4: CO_2 cap of the 11 European countries

	2012	**2015**	**2020**	**2030**	**2040**	**2050**
Million tons of CO_2	945.3	886.5	788.5	592.5	396.5	200.4

Table 5: CO_2 factors of primary energy combustion

t CO_2/MWh_{th}	
Lignite	0.399
Coal	0.339
Oil	0.266
Gas	0.201

Table 6: Gross electricity demand

TWh_{el}	**2015**	**2020**	**2030**	**2040**	**CAGR 2015-40**
AT+CH	131.8	140.0	149.4	158.1	0.7%
BE+NL	212.9	226.3	241.7	255.9	0.7%
DK	40.6	43.1	46.0	48.7	0.7%
FR	493.6	523.6	558.3	590.0	0.7%
DE	598.8	618.8	636.5	637.0	0.2%
GB	395.2	419.4	447.4	473.0	0.7%
IT	354.8	387.4	443.6	506.1	1.4%
CZ+PL	214.6	233.9	260.5	289.1	1.2%

Table 7: Power plant parameters

	Fixed Operation and Maintenance costs (EUR_{2010}/kW)	Generating efficiency [%]	Own consumption [%]
CCGT	23-28	48-60	3
Coal	36-55	37-50	8
Lignite	43-70	35-46,5	6
Gas turbine	17	35-40	3
Oil turbine	27	35-40	5
Wind onshore	13	100	
Wind offshore	93	100	
PV roof	17	100	
PV base	15	100	
Biomass solid	165	30	
Biomass gas	120	40	
Coal CHP	55	23	8
Gas CHP	40	36	2
Lignite CHP	45	23	6
Biomass solid CHP	175	25	
Biomass gas CHP	130	27	

Table 8: Investment costs of new power plant capacity

EUR_{2010}/kW	**2015**	**2020**	**2030**	**2040**
CCGT	675-725	675-725	675-725	675-725
Coal	1500-2350	1500-2250	1500-2000	1500-1850
Lignite	1500-2000	1500-1950	1500-1900	1500-1850
Gas turbine	375	375	375	375
Oil turbine	450	450	450	450
Wind onshore	1250-1290	1200-1255	1150-1190	1100-1130
Wind offshore	3500-3850	3200-3520	2800-3080	2650-2915
PV	1600-1700	1600-1650	1500-1550	1400-1450
Biomass solid	3300	3300	3300	3300
Biomass gas	2400	2400	2400	2400
Hydro storage	2300	2300	2300	2300
Pump storage	1200	1200	1200	1200