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Equilibrium Prices and Investment in Electricity Systems with CO_2-Emission Trading and High Shares of Renewable Energies

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1 INTRODUCTION

This paper analyses the future of the European electricity system. We use quantitative empirical equilibrium models to answer central questions for the decarbonization of electricity systems, especially the interdependencies between the European emission trading scheme and subsidies for renewable energies. We analyze the long term development until 2050 with endogenous consideration of investment decisions. For that purpose, we develop and compare two scenarios. Both scenarios assume that climate protection will be an important policy goal in Europe: in comparison to 1990 levels, CO_2-emissions in the European electricity supply industry have to be reduced by 80% (inside the framework of a continued European emission trading system (ETS)). The first scenario assumes that all European countries phase out of subsidies for electricity generation from renewable energy sources (RES) until 2020. Consequently, energy transformation is exclusively driven by the ETS in this scenario. The second scenario assumes that the current system with different national subsidy schemes for RES continues to exist in the long term. The two scenarios have identical assumptions on all other parameters (e.g. on the development of fuel prices, on the political acceptance of additional nuclear power plants in Europe, on Carbon Capture and Storage, …).

We couple two optimization models covering the European electricity market: one model optimizes 'conventional' power plant investment and dispatch decisions and one model optimizes investments in RES. Both models are formulated as linear programs and have cost minimization in the objective function. Main variables determined in the investment and dispatch model are how much capacity of different available generation technologies is installed where in Europe and how much electricity that capacity produces in any given time period. The RES model's main results are installed capacities for different RES technologies. The RES model endogenously considers learning effects by decreasing investment costs based on total in-stalled capacities. Both models are coupled iteratively to calculate market equilibria on the electricity market.

We use the quantitative results from the two scenarios to answer several policy relevant questions:

- Can RES cover their investment costs in an energy-only market with a sufficiently tight climate protection goal or do they need continued subsidization?
- How far (and how fast) will CO_2-prices rise to achieve emission reduction targets of 80% until the year 2050?
- What is the effect of additional subsidies for renewable energy sources on electricity prices, system costs (costs to society), shares of renewables in the electricity system and climate protection?

This paper is organized as follows: Section 2 gives a brief overview of the literature and describes the methodology. Section 3 discusses the main assumptions. Section 4 presents results and section 5 concludes.

2 METHODOLOGY

Researchers have developed a variety of electricity market models. These models can be categorized into at least three different classes: firstly, partial equilibrium models with a focus on technical constraints, secondly, agent based models and thirdly, oligopoly models with a focus on strategic behavior. We will use (and hence concentrate this section on) partial equilibrium models with detailed modeling of technical constraints.[1]

The electricity market – as any other market – is characterized economically by supply and demand. In the past, the supply side in most electricity markets consisted mainly of thermal power stations. Their dispatch was modeled in technical detail to serve exogenously given demand levels at minimal costs. Power plant dispatch models have been used in the past (e.g. by Borenstein et al (2002), Joskow and Kahn (2002), Müsgens (2006) and de Maere d'Aertrycke and Smeers (2010)).

Usually, RES generation is included in dispatch models by exogenously reducing demand by RES generation and feeding this 'residual demand' into the model. Unfortunately, this approach alone would not suffice for our research question as we want to know how much RES would be built based on scarcity signals on the electricity market. The most direct approach would be to include RES investment endogenously (i.e. directly) in the 'conventional' in-vestment and dispatch models. These models would have to be changed in several areas to do that. Firstly, a crucial aspect of dispatch models is the optimization of the production of power stations based on variable generation costs. RES dispatch is – on the contrary – most often not driven by variable generation costs but by the availability of their power source (e.g. solar irradiation or wind). Secondly, RES are often subsidized and hence not built based on market signals alone. Especially in feed-in tariff systems, RES investment is independent from electricity prices. Thirdly, different sites have different total costs depending e.g. on local solar irradiation, and the potential for investment at any given site is restricted. Hence, the investment and production problem of RES follows other constraints than conventional power plants. While these reasons do not principally hinder the integration of RES in electricity market models, they would make these models more complex to solve, e.g. require more computational power (and time). Hence, we used two different models, one model for RES investments and one model for power plant investment and dispatch. These two models are coupled in an iterative process described below. Thus, we are able to determine market equilibria on the electricity market.

In the following, we will describe the two models starting with the electricity market model. The model is formulated as a linear programming problem. The objective function is total system cost minimization. The model works under the perfect market hypothesis. Central constraints are: generation in a region must be equal to consumption in that region (plus imports minus exports) at all time periods. Power plants are grouped into technology classes (e.g. 24 different technology classes in the region 'Germany'). Within these technology classes, power

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1 An overview of agent based electricity market models is given by Weidlich and Veit (2008). Explicit modeling of market power is often done with supply function equilibria models, pioneered by Bolle (1992) and Green and Newbery (1992).

plants can only produce electricity if they are started up. Capacity started up cannot exceed installed capacity in a technology class. Key variables optimized by the model are power generation by technology class and load level and investment in new capacity. Other results (CO_2-emission prices and wholesale electricity prices) can be derived as shadow prices of the relevant constraints. It is important to note that the cost minimal solution derived by these models is equivalent to the result of market coordination under the assumptions of perfect markets. For this reason, our electricity market model calculates a partial equilibrium on the European electricity market. We give a detailed and formal presentation of the objective function, the constraints and the relevant variables and parameters in Lenzen et al. (2012).

The model comprises the 27 member states of the European Union (plus Norway and Switzerland). These 29 countries are grouped into 11 regions. Inside regions, we abstract from grid constraints. Between regions, power exchange is endogenously optimized by the model, but power exchange is limited by available net transfer capacities (NTC-values). The models cover the time period from 2020 to 2050 (with one representative model year every 5 years, i.e. 2020, 2025, 2030, ..., 2050). During each representative model year, 4,380 chronological load levels are differentiated (one load level for every two hours of the year).

This resolution – both with respect to time and regional coverage – in our model is higher than in the papers cited above. In part, this is due to technical progress (faster computers). In part, it became a necessity capturing economic essentials of the problem as a system with higher shares of fluctuating RES is more volatile. In today’s electricity markets with significant shares of RES, this is increasingly important.

The whole system in the model consisting of 11 regions, 4,380 load levels and seven representative years is solved simultaneously. This is necessary for several reasons: firstly, power plant dispatch in load level n cannot be solved independently from the other load levels. For example, costs in n depend on whether the plant was already started-up before or not (see Kuntz and Müsgens 2007 for the dynamic effects of start-up costs). Furthermore, the dispatch of hydro storage (and even more important) pump storage can only be calculated correctly when at least a whole cycle (for seasonal storage one year) is simultaneously optimized. Last but not least, new investments are undertaken if (discounted) future revenues cover investment costs. As power plants have a lifetime of 40 years and more, revenues in future model years influence a profitability of a power plant (and hence the investment decision).

The second model is a model of RES technologies. It also covers the 27 countries of the EU plus Norway and Switzerland. However, as electricity production costs from RES differ significantly within a country, the model divides countries into sub-regions. The model has a flexible set-up so that different subsidy schemes for RES can be modeled. For an in-depth discussion of the RES model, refer to Wissen (2012). In particular, the paper gives a formal description of the model (equations, constraints, variables, and parameters) on pp. 174-197.

In the following, we present the two scenarios and describe the coupling of the two models necessary to compute market equilibria. The first scenario is called ‘scenario integration’. It assumes that climate protection in the European emission trading scheme is the only policy instrument to drive the change towards a low carbon energy system. In particular, no additional RES-specific subsidy is included. This scenario answers the central question how much RES will be built when and where in an environment without RES-specific subsidies. Furthermore, if climate protection would be the only reason for both climate protection and RES capacity additions, this scenario would calculate the most economically efficient way. RES are exclusively financed by the revenues they receive from selling electricity on the wholesale electricity market. The calculation of the market equilibrium requires an iterative coupling of the electricity market model and the RES model. This is necessary because RES capacities (calculated in the RES model) influence the electricity price (calculated in the electricity market model EMM) – and vice versa. The iterations are performed as follows: the EMM uses starting values for RES feed-in profiles in all model regions for all periods of observation and optimizes the conventional electricity system. Resulting wholesale electricity prices and market values for RES are transferred to the RES model. Taking these electricity prices and market values (due to their specific generation profile, RES plants earn more or less than the average electricity prices, see Joskow 2011) as exogenously given, the RES model computes how much RES capacity would be built and what the respective RES feed-in profile would look like. Note that electricity prices are the only revenue source for RES investment in the integration scenario. Starting the next iteration, the resulting RES feed-in profile is (again) transferred to the electricity market model which takes them as exogenously given. This process is repeated until convergence.

A second scenario (business as usual, 'scenario BAU') assumes RES production is policy driven. Governments are assumed to have explicit goals for the amounts of generation for different RES technologies. Hence, we include lower bounds (i.e. minimal amounts) for RES production for all RES technologies, years and countries. As these bounds are often above the market based solution, the implicit assumption is that RES receive subsidies in addition to the revenues from selling electricity. The RES model described above is used compute how much capacity is needed per technology and country to fulfill these energy requirements, where in the country it will be built (starting with the good, i.e. cheap sites, and moving down to more expensive sites if necessary to fulfill RES energy constraints) and how much this will cost. In the BAU scenario, an iterative coupling of the two models is not necessary as wholesale electricity prices do not influence RES production in this scenario. Hence, we simply calculate RES feed-in with the RES model taking into account the constraints for minimal RES generation. Resulting feed-in profiles are transferred to the electricity market model.

3 ASSUMTIONS

As the interaction between the EU emission trading scheme and investment in renewable energy sources is one of our main research questions, we assume that climate protection will remain one of the cornerstones of European energy policy. As of today, binding targets until the year 2020 are in place. In particular, CO_2-emissions have to be reduced until 2020 by 20% compared to 1990 emissions on the European level (for details and the implications on the European emission trading scheme, refer to e.g. EU 2012). Post-2020, no binding targets exist so far. However, a total emission reduction of 80% until 2050 is discussed e.g. in EU (2011).

We assume that compared to 1990 levels, CO_2-emissions in the European electricity generation sector must be reduced by 80% until 2050. Sometimes, e.g. in EU (2011), it is argued that the power sector must reduce emissions over-proportionally if aggregated emissions in all sectors should be reduced by 80%. Event tighter climate protection would be beneficial for the profitability of RES. In that regard, our assumption of an 80% reduction within the power sector is conservative, more RES would be built with tighter climate protection. Figure 1 shows CO_2-emissions in the European electricity market. Historic values for 1990 and 2010 are shown for comparison. 2020 levels contain left-overs from trading period two and three which were not used due to unexpectedly low economic growths (especially in southern Europe) and unexpectedly high RES generation which both made the ETS less tight than expected (and led to the low current prices).[2] Nonetheless, the figure shows how limited emissions are in the power sector in the long term. As we developed a dynamic model which optimizes all model years simultaneously, we can also optimize banking of certificates. We assume that 25% of the available emission certificates in any particular model year can be moved to the next model year.

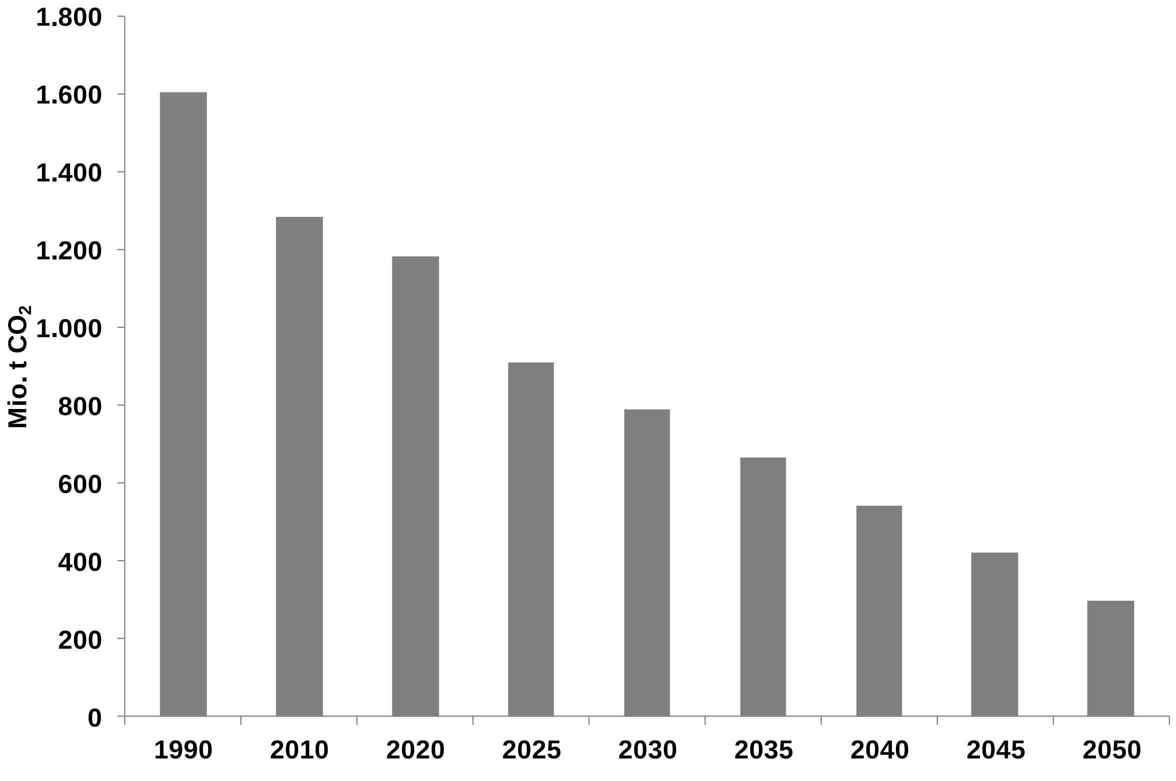

Figure 1: Assumed Targets for European Emission Trading System

A number of other assumptions are also relevant in the context of electricity market modeling: As the model concentrates on the electricity market, it does not endogenously optimize fuel

[2] Following Deutsche Bank Research (2012), we assume 1,264 million t CO_2 as aggregated left-over in 2020.

prices – which are often determined on a world market. Instead, we assume exogenous developments for fuel prices taken from the literature. This assumption seems justified because the fuel price effect a moderate change in European (and especially German) demand for these primary fuels might have seems limited in comparison to growing markets e.g. in China. We take fuel prices from the World Energy Outlook (IEA, 2011). A graph on fuel price assumptions is presented in the appendix. Fuel prices – and all other currency denominations in this paper – are real and discounted to the base year 2012.

Furthermore, we assume that electricity demand is exogenously given. We use annual consumption estimates from Eurelectric (extended with a reduced growth rate post 2030). The respective estimates are also presented in the appendix.

One more assumption concerns future investment costs for renewables. It seems very likely that these will decrease faster than investment costs for conventional thermal capacity. We use the assumption that investment cost reductions depend on aggregated installed capacities, i.e. cost reductions can only be achieved if investment takes place. As investment decisions in RES in Europe are determined by the model, cost developments have both exogenous as well as endogenous components. Exogenous are our assumptions on learning rates which we define as a reduction in investment costs per doubling of installed capacity. We assume that this learning is based on global installed RES capacities. As we only endogenously model RES investments in Europe, we need additional assumptions on exogenous RES investments out-side Europe. The latter are presented in the appendix.

Table 1: Learning Rates for Renewable Energy Technologies

	Learning Rates in %
Wind Onshore	4%
Wind Offshore	4%
Photovoltaics	15%

Furthermore, as climate protection is one of the key issues in this paper, it is important to discuss the other low carbon technologies, in particular nuclear energy and carbon capture and storage (CCS). Both need assumption on the political framework in addition to investment cost assumptions already presented. Fur nuclear, we take into account the change in political acceptance after the severe nuclear incident in Fukushima Daiichi. We assume that all European countries who have decided to phase out of nuclear will do so. In countries without such legislation, installed nuclear capacity is restricted by aggregated capacities currently installed (plus projects under construction). Furthermore, we assume investment costs of 4000 €/kW for new nuclear. This is relatively high an in part due to increased safety regulations. Inside this framework, the model can optimize nuclear investment, e.g. replace old plants with new ones. Concerning CCS, we included that technical option in all European countries. This assumption is pessimistic for the profitability of RES as RES would benefit from reduced competition of other low carbon technologies. Hence, more RES would be built when prohibiting CCS (sensitivities we calculated do indeed confirm improved profitability for RES without this option).

Last but not least, we assume that a shift towards a more efficient subsidy system as described in the integration scenario takes some time. In practice, such a scenario would not only necessitate moving away from 'hand-picked' technology specific subsidies as we have them in many countries today. Furthermore, it would mean abandoning national RES targets and trusting the ETS to be an efficient mean to reduce CO_2-emissions. While a slow movement towards increased efficiency in the European energy system might be expected, the huge step our integration scenario assumes will take time. Hence, we assume an adaption phase until 2020. Hence, we assume identical starting values in 2020 for both scenarios. RES expansion between now and 2020 is based on National Renewable Energy Action Plans. In the scenario integration, no further assumptions on RES are needed. However, in the BAU scenario, policy goals for RES production are needed for every country, year and RES technology. Based on a literature survey, we assume that the share of RES in relation to gross electricity consumption will be 60% in Europe and 66% in Germany in 2050.[3]

4 RESULTS

The first result we present is the future development of CO_2-prices. As Figure 2 shows, CO_2-prices rise significantly post-2020. This is due to the assumed continuation of CO_2-emission reductions in the European electricity market.

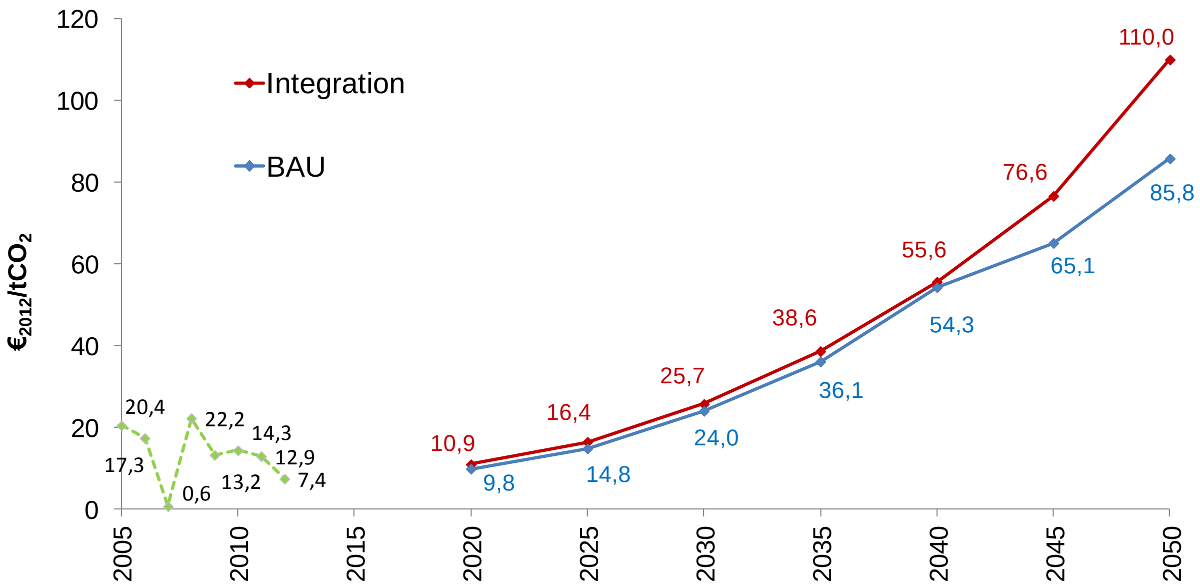

Figure 2: Development of CO_2 Prices

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[3] The current policy goal in Germany is even higher (80%). However, scenarios reaching 80% RES in 2050 in Germany, e.g. BMU Leitstudie 2011, usually assume that Germany imports RES-electricity (e.g. from projects such as desertec) and most often assume a significant reduction in Germany electricity consumption. If we would increase exogenous RES generation in the BAU scenario even further, total costs (and cost differences to the efficient scenario integration) would rise further.

We showed in the assumptions how tight the system becomes in terms of CO_2-emissions if a reduction of 80% is desired until 2050. In particular, it is impossible to serve the increasing demand for electricity with conventional technologies such as coal or gas fired capacity alone. Instead, an increasing amount of low carbon technologies is needed to serve demand without violating the emission boundaries (see be-low). Technically speaking, the system becomes infeasible without adding RES, nuclear or carbon capture and storage technologies (CCS). This change in the system is driven by the increasing tightness in the emission trading system. CO_2-prises must rise to raise electricity prices and thus make the low carbon technologies feasible.

Figure 3 confirms that a significant amount of RES becomes indeed competitive. The figure shows total RES generation as well as generation by thermal technologies. Starting with the integration scenario on the left, we see that RES generation in Europe increases continuously from 2020 onwards. In 2050, RES generation covers nearly 50% of total electricity consumption. Thus, RES generation does not only cover the increase in total electricity demand from 2020 to 2050 but also replaces thermal generation. Especially from 2030 onwards, thermal generation is decreasing. Once again, the integration scenario pushes that development based on rising CO_2-emissions alone. No RES-specific subsidies are paid.

In the business as usual scenario, the share of RES increases even further (but as we said in the last section, this increase is due to our exogenous assumptions). It is interesting to note which capacity is replaced by the additional RES. This can be seen on the right in the figure. While the BAU scenario has more RES, it has significantly less hard coal generation and a slightly lower nuclear generation.

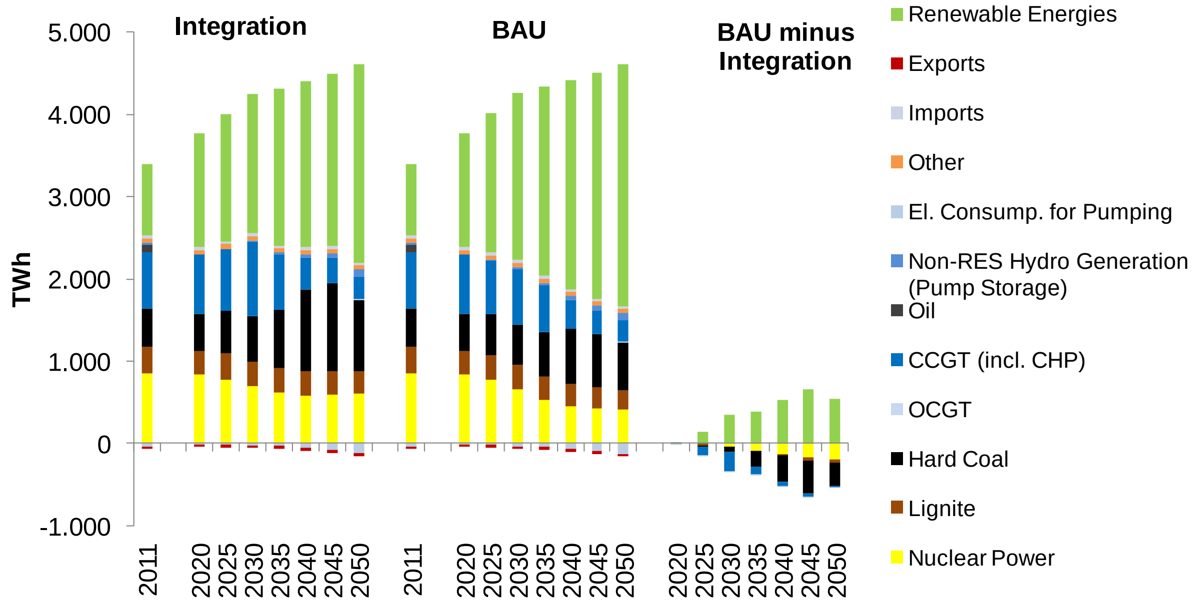

Figure 3: Electricity Generation in Europe

The integration scenario calculates the cost minimizing way for efficient climate protection. Any alternative, for example a continuation of national subsidy schemes for RES as described in the BAU scenario, must be more expensive. The following Figure 4 shows the cost comparison between the two scenarios (total costs per year including annualized investment costs, scenario BAU minus scenario integration). Cost differences between the two are virtually zero in 2020 as both scenarios have the same starting point in 2020. After that, the costs for RES (in green) are higher in the BAU scenario. On the other hand, less conventional generation (and capacity) is needed. Hence, these costs are higher in the integration scenario. However, as can be seen by the line denoting total differences, scenario BAU is less efficient exhibiting higher costs. The highest cost difference is around 40 billion €2012 in the year 2040.

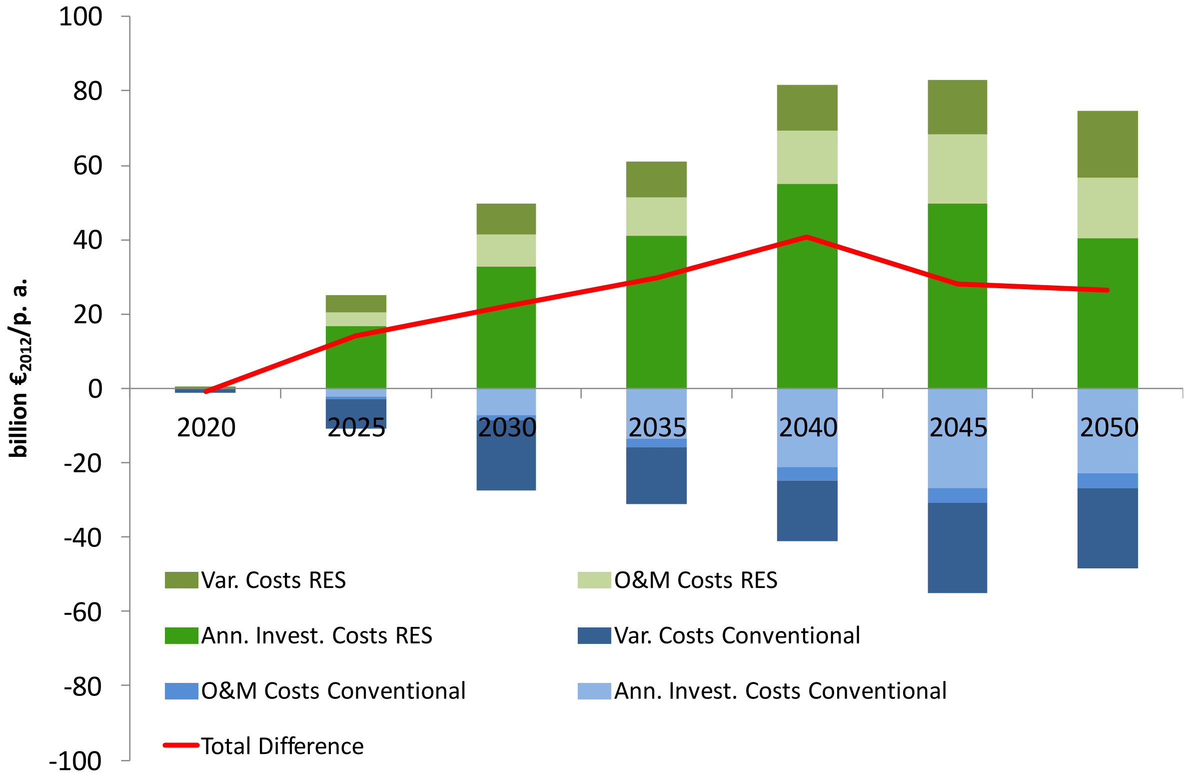

Figure 4: Annual Cost Differences between the two Scenarios (‘BAU’ minus ‘Integration’)

Besides looking at the aggregated European perspective, our model can also provide dis-aggregated results for the different model regions. We use the example of Germany to demonstrate additional results and derive additional conclusions. Currently, Germany is one of the forerunner states for a movement towards a green electricity system. However, our results show that the shares of RES in electricity generation would decrease post 2020 in an efficient market with climate protection being the single driver to build a new energy system (i.e. scenario integration).

There are two reasons for this. Firstly, on a European scale, several countries are superior to Germany with regard to RES cost structures. For example, Spain has about twice as much solar irradiation and thus about half the cost per kWh of electricity from photovoltaics (assuming identical investment costs per kW). Secondly, compared to other European countries, Germany has already built so much RES (and we assume the country will continue to do so until 2020) that in comparison to other countries and the efficient market equilibrium the country is ‘over-endowed’. As a consequence, our results show that it takes until 2050 for Germany to re-reach the 2020 levels of RES generation. In contrast to that, the BAU scenario assumes significantly more RES in Germany.

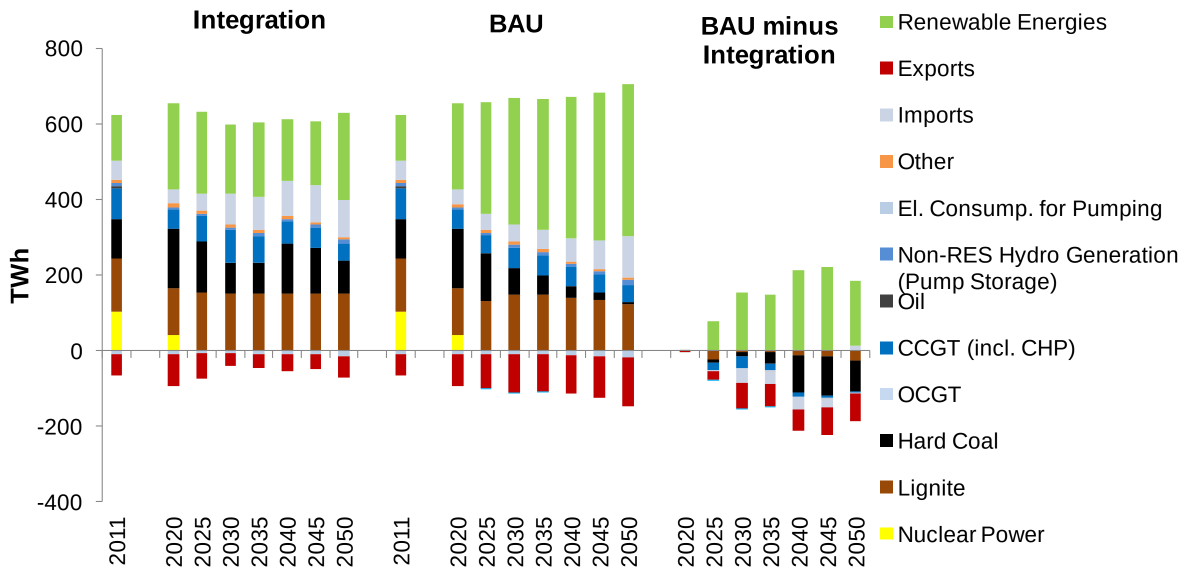

Figure 5: Electricity Generation in Germany

Figure 6 shows wholesale electricity prices in Germany for the two scenarios as calculated by the models.[4] We see that especially in the integration scenario, wholesale electricity prices will increase significantly in the future. As we have pointed out, this increase is necessary to drive the change in the system towards low carbon technologies.

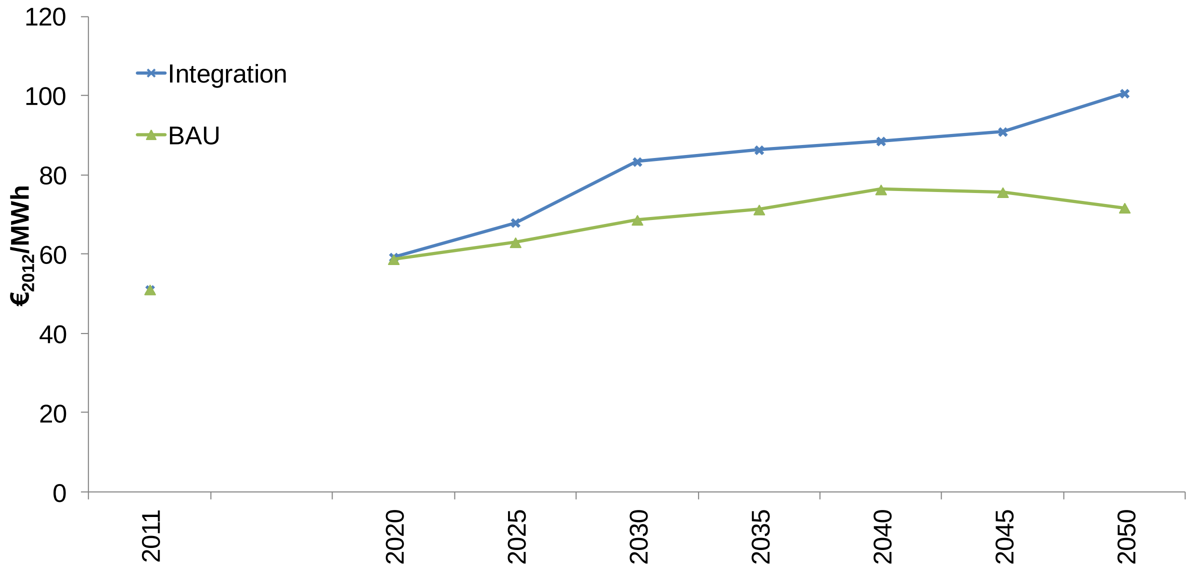

Figure 6: Development of Wholesale Electricity Prices in Germany

4 As we have pointed out, these and all other currency figures are discounted to 2012 real values.

It is to a large part the result of the increase in CO_2-emission prices (results were presented in Figure 2) In the BAU-scenario, the increase is less pronounced as RES are not built based on market signals alone but are assumed to be built exogenously (and under the assumption that they receive additional subsidies). These additional subsidies will drive up costs for consumers but are not included in wholesale electricity prices. They might be included in retail electricity prices or paid via general taxes. Hence, wholesale electricity prices in equilibrium are higher in the integration scenario, but this price covers all costs in the system.

5 CONCLUSION

We develop and compare two different scenarios for the future of the European electricity system. In one scenario, the electricity system will be changed towards an economically more efficient system with respect to climate protection. Instead of pursuing this goal with different instruments (i.e. emission trading scheme and RES subsidies), we focus this scenario on the emission trading scheme alone. In another scenario, we develop a business as usual scenario with continued subsidies for RES and a parallel emission trading system.

What is of particular interest in our analysis is how much RES generation will increase even without RES-specific subsidies. Our results show that about 50% of gross electricity consumption in Europe will be generated from RES in the year 2050 based on climate protection and ETS alone. Furthermore, RES generation increases continuously from 2020 onwards. Equilibrium prices for CO_2-emission certificates rise significantly in the long run to make these investments in RES (and other low carbon technologies), which are necessary to comply with the CO_2-emission goals, profitable.

However, in a cost efficient solution, RES will not be evenly distributed across Europe. For example, the situation for RES is less favorable in Germany. Due to a relatively high starting value in 2020 (which includes a significant amount of RES production at relatively unfavorable locations), shares for RES will decrease in this scenario post-2020 (and recover slowly).

While our integration scenario can be interpreted as an efficiency benchmark if climate protection is the only goal of both the ETS and RES subsidies, additional goals of RES subsidies (job growth, less import dependency, conservation of non-renewable resources, ...) could possibly justify higher costs. It is an interesting question for further research, how much of the additional costs could be justified by any of these additional goals.

APPENDIX

Table 2: Development of Electricity Demand (in TWh per year) for all Countries (Eurelectic and own calculations, 2012)

		2011	2020	2025	2030	2035	2040	2045	2050
AT	TWh	66,0	75,5	81,0	86,5	88,0	89,5	91,1	92,6
BE	TWh	88,7	113,9	109,9	105,8	102,0	98,3	94,7	91,3
BG	TWh	40,0	52,7	60,1	67,4	69,5	71,7	74,0	76,3
CH	TWh	63,1	69,0	72,5	76,3	77,2	78,2	79,2	80,2
CY	TWh	5,5	7,2	9,4	11,5	12,2	13,0	13,8	14,6
CZ	TWh	64,5	77,5	80,3	83,0	83,7	84,4	85,2	85,9
DE	TWh	**558,4**	**558,4**	**558,4**	**558,4**	**558,4**	**558,4**	**558,4**	**558,4**
DK	TWh	35,7	38,2	41,0	43,8	44,6	45,3	46,1	46,9
EE	TWh	9,0	10,1	10,8	11,6	11,8	12,0	12,2	12,4
ES	TWh	286,0	340,0	375,5	411,0	420,9	431,1	441,5	452,2
FI	TWh	84,5	99,0	104,0	109,0	110,3	111,7	113,0	114,4
FR	TWh	493,3	523,1	538,7	554,3	558,3	562,4	566,5	570,6
GB	TWh	361,5	397,4	413,0	428,5	432,6	436,7	440,8	445,0
GR	TWh	60,8	69,3	74,6	80,3	81,8	83,4	84,9	86,5
HU	TWh	40,4	47,0	50,6	54,2	55,2	56,2	57,2	58,2
IE	TWh	27,4	30,1	31,3	32,5	32,8	33,1	33,5	33,8
IT	TWh	338,7	424,0	482,1	548,1	566,1	584,8	604,0	623,9
LT	TWh	10,9	13,4	16,2	19,0	19,9	20,7	21,7	22,6
LU	TWh	6,4	7,2	7,4	7,5	7,5	7,6	7,6	7,7
LV	TWh	7,3	8,9	9,9	10,8	11,1	11,3	11,6	11,9
MT	TWh	2,2	2,4	2,4	2,5	2,5	2,6	2,6	2,6
NL	TWh	117,4	132,4	143,1	153,7	156,6	159,6	162,6	165,7
NO	TWh	125,6	138,0	142,0	146,0	147,0	148,1	149,1	150,2
PL	TWh	143,0	171,7	197,0	222,2	229,5	237,1	245,0	253,1
PT	TWh	54,3	62,2	69,9	77,6	79,8	82,1	84,4	86,8
RO	TWh	56,8	64,2	72,6	81,0	83,4	85,8	88,4	91,0
SE	TWh	139,1	144,6	145,6	146,5	146,7	146,9	147,2	147,4
SI	TWh	12,8	14,9	16,3	17,7	18,1	18,5	18,9	19,4
SK	TWh	27,2	35,2	37,4	39,5	40,1	40,7	41,3	41,9
Europe	TWh	**3.326,3**	**3.727,5**	**3.952,4**	**4.186,1**	**4.247,7**	**4.311,1**	**4.376,3**	**4.443,4**

Table 3: Investment Costs for Conventional Technologies (own calculations)

	Investment Cost	Efficiency Factor New Capacity
	€$_{2012}$/kW	%
Nuclear	4.000	34%
Lignite	1.900	46%
Lignite CCS	3.800	39%
Hard Coal	1.700	45%
Hard Coal CCS	3.400	37%
CCGT (inc. CHP)	900	60%
OCGT	500	42%

Table 4: Development of Newly Installed Capacity in Countries outside EU-27 (own calculations)

	2011	2015	2020	2030	2040	2050
	GW					
Wind Onshore	144	252	425	670	950	1.180
Wind Offshore	0	2	14	103	203	281
Photovoltaics	19	48	116	375	740	1.166

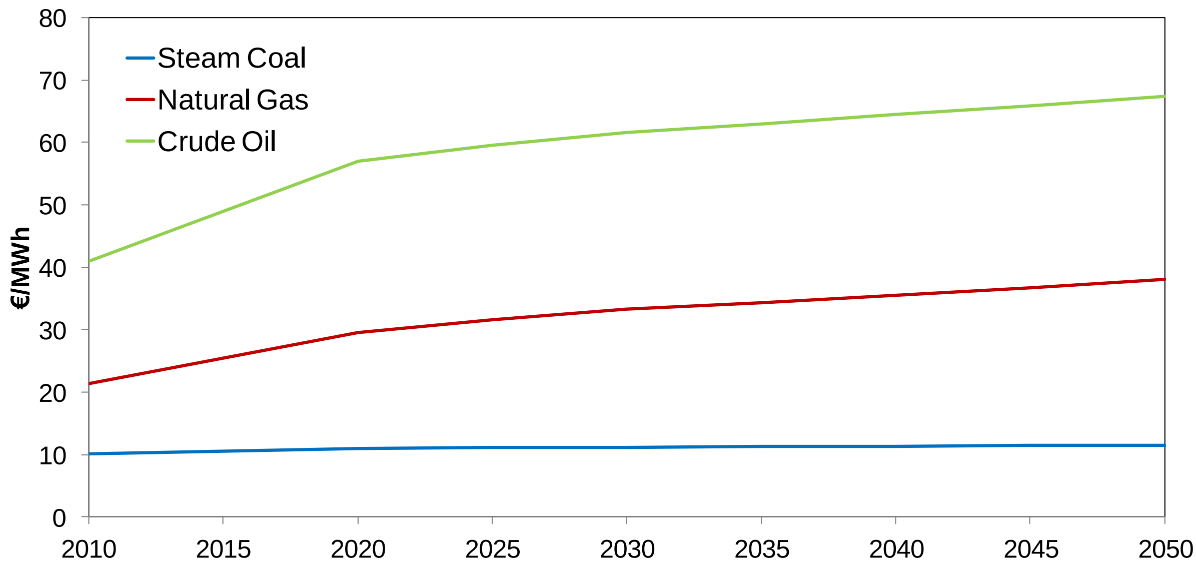

Figure 7: Development of Primary Fuel Prices (IEA, 2011)

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