Co-firing Coal with Biomass under Mandatory Obligation for Renewable Electricity: Implication for the Electricity Mix

*Vincent Bertrand**

ABSTRACT

This paper analyses the effect of recognizing co-firing coal with biomass as renewable electricity. We provide simulations for the French and German electricity mix. Results indicate that, if co-firing is recognized as a renewable, coal may crowd-out traditional renewables with increased generation and additional investments. Regarding CO_2 emissions, we find surges when co-firing is recognized as a renewable. The rise is more significant in Germany due to greater coal capacity. In France, the magnitude depends on the share of nuclear with a lower increase when old nuclear plants are prolonged. Finally, we find that recognizing co-firing as a renewable reduces the overall costs for electricity. We balance the cost saving with the increased social cost from higher CO_2 emissions. Results show that the cost saving is lower than the increased carbon cost for society with carbon valuation around 100 Euros/tCO_2, except in France when old nuclear plants are not decommissioned.

Keywords: Co-firing, Biomass, Renewable electricity obligation, Electricity mix, CO_2 emissions, Social cost of carbon.

https://doi.org/10.5547/01956574.40.4.vber

1. INTRODUCTION

In the last few years, co-firing coal with biomass has become very popular in the European power sector, where firms have to comply with stringent policies to reduce CO_2 emissions and increase their output of renewable electricity. Co-firing provides short-term opportunities for increasing the share of renewable energy sources (RESs) and reducing CO_2 emissions in a very cost effective way through conventional technologies that are not subject to problems of intermittency and that do not require additional investments.

In addition to exemption from surrendering CO_2 allowances under the European Union Emission Trading Scheme (EU ETS) when burning biomass (equivalent to a zero emission factor), several European states have implemented arrangements to include co-firing in their support schemes for renewable electricity (e.g. Poland, UK, Denmark, Netherlands), which raised concerns about the consequences for the contribution from coal to the electricity mix (even through co-firing with biomass) and the resulting CO_2 emissions. As recently pointed out in debates on energy agreements in the Dutch parliament, it may seem strange that some coal plants are set to close down due to environmental regulation while the same units can receive subsidies when co-firing biomass. This raises questions about the actual incentives to invest in *traditional* RES technologies (e.g. wind, solar, dedicated biomass units) to meet European targets and the consequences for future energy mixes.

* CRESE EA3190, Univ. Bourgogne Franche-Comté, F-25000 Besançon, France. Climate Economics Chair, Univ. Paris Dauphine, Paris, France. E-mail: vincent.bertrand@univ-fcomte.fr.

In the same way as for natural gas, co-firing has often been pointed to by practitioners from the energy industry as a transitional technology, which may limit the CO_2 emissions from existing power fleets in the short run, before deployment of a true energy transition in the long run, with a carbon-free power sector. However, whereas co-firing reduces the carbon intensity of coal plants (compared with the classical configuration when coal is the only input), it still generates CO_2 emissions. Hence, if coal is maintained and co-firing diverts investments away from traditional RES, it is to be expected that CO_2 emissions from electricity will be higher in the long run (compared with a more radical energy transition in which pure renewables dominate the fleet of power plants). Accordingly, any policy that promotes co-firing as a renewable may result in higher CO_2 emissions in the long run, if it gives incentive to use coal plants under co-firing instead of investing in the RES carbon-free technologies. In this context, this paper aims to investigate *what would happen if* co-firing, which *is thought of as a transitory option* by some (but also receives support from renewable schemes in some countries, see section 2), is continued and *becomes a long-term solution*.[1] We focus on European countries with simulations for France and Germany. However, beyond the case of Europe and other developed countries, we believe this paper may help to understand what could happen in developing and emerging countries if co-firing is used to develop RESs. Given the high share of coal in the generation mixes of these countries, this may be a big question in the future. This paper provides some insights that may help to anticipate this issue.

The question of the consequences of promoting co-firing as renewable electricity has attracted little attention in the economic literature. To date, to the best of our knowledge, the only contribution comes from Lintunen and Kangas (2010) who provides a theoretical model to analyze the effect of co-firing in a stylized and simplified power system. The authors consider profit maximizing power producers that optimize production and investment decisions so as to meet static power demand. Investments in renewables are modeled as demand for new wind turbines (the only renewable technology in the analysis) that can increase the production capacity with the aim of meeting the static power demand at the lowest cost. Results show that promoting co-firing as a renewable decreases investments in pure renewable technology, whereas the CO_2 intensity of electricity is not significantly impacted. However, although Lintunen and Kangas (2010) illustrate their results through a numerical application with parameters reflecting the Finnish power sector, they fail to provide comprehensive estimations of investment decisions over a complete power system management including elements such as a dynamic time horizon, the decommissioning of old capacities, or increasing demand for power. Notably, their modeling approach with a simplified power system cannot be used to investigate the consequences for long-term CO_2 emissions when the electricity mix is continuously modified by policies promoting co-firing against pure renewables and carbon-free technologies. Considering a more detailed treatment of power systems through simulations with a dynamic time horizon is likely to produce more significant effects when co-firing steadily displaces traditional RES technologies over time, resulting in a power plant fleet that is more carbon intensive in the end. This is the starting point of our analysis, which extends the previous contribution by Lintunen and Kangas (2010).

Compared with previous work, this paper uses a simulation approach to analyze the consequences for the electricity mix when co-firing is recognized as renewable electricity. We use the

1. It is worth mentioning here the literature that is increasingly questioning the risk associated with "weak near-term" solutions for climate (such as substituting natural gas or co-firing for dirtier fossil based power stations), which are seen as delayed mitigation actions that may continue more than expected and may increase the cost of meeting the long-term mitigation targets or even make them impossible to reach (Clarke et al., 2009; Calvin et al., 2009, Jakob et al., 2012; Luderer et al., 2012; Luderer et al., 2016; De Perthuis and Solier, 2018). See Luderer et al. (2016) for a detailed literature review.

Green Electricity Simulate (GES) model, which is a simulation model for electricity designed to focus on biomass-based electricity and co-firing in European countries (Bertrand and Le Cadre, 2015). In order to assess the effect of promoting co-firing as a renewable option, we run the model with and without co-firing in the set of RES technologies that are accounted for to meet the RES targets. Our simulations rely on a detailed representation of the power system, which can be used to derive more general results taking into account elements such as a dynamic time horizon, the decommissioning of old capacities, rising demand for power or increasing renewable targets. This extends the study by Lintunen and Kangas (2010).

As an illustration, we provide simulations for France and Germany, which offer good cases of study for our analysis because they have large coal capacities (even in France where the coal capacity is not negligible in volume with respect to other European countries, see Table 3) and because no support scheme for co-firing has been implemented in these countries so far. Hence, France and Germany provide relevant counterfactuals with which to investigate the consequences of implementing such provisions that recognize co-firing as renewable electricity. The case of France is also interesting regarding the effect of nuclear reduction that may greatly impact the electricity mix in this country. Whereas French electricity has historically been highly dependent on nuclear power, a law on “energy transition” was passed in 2015, which aimed at reducing the share of nuclear power by 2025.[2] Although the full application remains uncertain, such a reduction of French nuclear power combined with the RES targets is likely to be offset by some RES power plants, to which co-firing may contribute if counted as a renewable. This is something of interest for our study.[3]

Results confirm that recognizing co-firing as an RES would jeopardize investments in traditional RESs, which would be largely ousted in favor of increased generation from existing coal power stations under co-firing plus some new investment in coal. The additional coal investments are more substantial in France because French coal capacities are lower than German capacities, thus limiting the scope for using existing coal plants to meet the RES targets through co-firing. The additional French coal capacities may reach 18 GW when the model is implemented with exogenous decommissioning of old nuclear power plants. Comparatively, the maximal additional coal capacity in Germany is close to 14 GW when co-firing is included in the set of RES, which corresponds to a progression of about 27% for coal in 2030 compared with the initial capacity, whereas the same progression is more than 243% in France when old nuclear power stations are decommissioned (107% when nuclear plants are prolonged), with almost 26 GW of coal accounting for 20% of the 2030 French capacity mix. Hence, including co-firing in RESs may more radically change the French capacity mix, in which coal may change status and become an important source of French electricity output.

Regarding CO_2 emissions, results indicate that recognizing co-firing as an RES generates sharp increases because of reduced traditional RESs (carbon-free) and more coal in electricity. This effect is more significant in Germany than in France due to its much greater coal capacities. Moreover, in the case of France, the magnitude of the carbon increase depends largely on the share of nuclear power, with fewer increases when old nuclear power stations are prolonged. Finally, we show that including co-firing in the set of RESs reduces the overall costs associated with managing

2. *Loi n° 2015–992 du 17 août 2015 relative à la transition énergétique pour la croissance verte* (www.legifrance.gouv.fr).

3. In France, the electricity mix is largely dominated by nuclear power, which represents more than 50% of installed capacity, and around 75% of power generation (76% in 2015, according to RTE, *Statistiques Production Consommation Echanges 2015*). In comparison, nuclear power accounts for about 5% of all installed capacity in Germany (ENTSO-E, 2016), and it generated 14.2% of German electricity in 2015 (*Gross electricity production in Germany from 2014 to 2016*, www.destatis.de).

the power system, because this allows compliance with the RES constraint through a conventional and low-cost option that does not require additional investments. When balancing this cost saving against the increased social cost from higher CO_2 emissions, results show that the cost saving may be dominated by the increased carbon cost with a high carbon valuation around 100 Euros per tCO_2. An exception comes from France when the service life of ageing nuclear power stations is prolonged. In this case, the cost saving is very high and the increased CO_2 emissions are slight (because massive cheap and carbon-free nuclear power continues to be used for base-load generation) with the result that the cost saving always dominates the increased carbon cost.

The remainder of the paper is organized as follows. Section 2 gives an overview of existing support schemes for renewable electricity in European countries that include provisions for co-firing. In section 3, we provide an overview of the economic literature on co-firing and a brief presentation of the methodology and data. Section 4 presents the results and discussions. Section 5 concludes.

2. CO-FIRING IN THE RENEWABLE ELECTRICITY SUPPORT SCHEMES OF EUROPEAN COUNTRIES: AN OVERVIEW

The option to co-fire biomass with coal has been implemented in numerous European coal-fired power stations. Major co-firing applications include large coal plants such as Ferrybridge (2000 MW, UK), Fiddler's Ferry (2000 MW, UK), Amer (1000 MW, Netherlands), Gelderland (630 MW, Netherlands), Ensted (620 MW, Denmark), and Lagisza (460 MW, Poland).[4]

The treatment of co-firing in support schemes for renewable electricity is highly heterogeneous among European countries. In general, in most cases, co-firing is not counted as an RES, and, as such, it is not subsidized. However, there are notable exceptions to this, with some countries that generate significant amounts of electricity from coal having included provision for co-firing in their support schemes. Table 1 provides an overview of treatments for coal plants under co-firing in support schemes from different European countries.

In the UK, banding has been introduced awarding different co-firing configurations at various rates of certificates. Whereas 1.5 Renewables Obligation Certificates (ROCs) are given for each MWh of electricity generated in dedicated biomass units, the ROC rate (ROC per MWh_{elec}) is less than one when co-firing is involved. The rate ranges from 0.3 to 0.9 depending on the percentage of biomass co-fired (Table 2).

The UK system used to be more generous regarding co-firing, with one ROC per MWh_{elec} of co-fired electricity regardless of the configuration. In order to avoid excessive development of co-firing in the country, banding has been introduced so as to limit the level of subsidy. Nevertheless, even with the banding system, co-firing biomass with coal still tends to be more cost effective than investing in new dedicated biomass units.

In the Netherlands, another country with high co-firing, the SDE+ (*Stimulering Duurzame Energie*) auction subsidy-system for renewables provides producers of co-fired electricity with grants as for other RESs. The SDE+ was introduced in 2015 and basically the (sealed-bid) auction gives bonus payments to compensate for the difference between the market prices for electricity

4. The Drax power station (UK) is known as the world biggest biomass-based power station with 1220 MW of 100% biomass generation capacity, i.e. two of the six Drax units (conversion of a third unit has been recently decided, which will increase the biomass capacity to 1880 MW). Such a conversion project would not be considered as co-firing because it burns biomass only, and, in the UK, it is entitled to receive a more generous subsidy treatment than co-firing (Table 2).

Table 1: Treatment for co-firing in support schemes of European countries (Bubholz and Nowakowski, 2010).

Country	Subsidy for co-firing—Euros/MWh_{elec} in 2010	Support system
Austria	63[a]	Feed-in-Tariff
Belgium	0	None
Denmark	20[b]	Feed-in-Premium
Estonia	0	None
Finland	0	None
France	0	None
Germany	0	None
Italy	0	None
Latvia	0	None
Lithuania	0	None
Norway	0	None
Poland	64	Green Certificates
Spain	20[c]	Feed-in-Premium
Sweden	28[d]	Green Certificates
Netherlands	61	Feed-in-Tariff
United Kingdom	25[e]	Green Certificates

[a] Maximal value. Reductions can be applied depending on the biomass material (up to 50% for lowest quality).
[b] A subsidy is given for each tonne biomass that is burned (depending on local agreements), in addition to certificates.
[c] Reference value. The actual premium is calculated based on the plant data (e.g. energy output, investment cost, biomass material).
d Only the biomass part can receive certificates.
[e] Value with 0.5 certificates per MWhelec (the applied rate of certificates depends on the percentage of biomass in the coal plant).

Table 2: Cost of generating electricity with biomass in the UK under ROC banding (Argus, 2016; Alexander et al., 2013).

	ROC rate	ROC value (Euros/MWh_{elec})[a]	Electricity Cost (Euros/MWh_{elec})[b]
Dedicated biomass	1.5	78.60	117.41
Conversion – 100% biomass	1	52.40	91.21
Co-firing – More than 85% biomass	0.9	47.16	85.97
Co-firing – 50 to 85% biomass	0.6	31.44	70.25
Co-firing – Up to 50% biomass	0.3	15.72	54.53

[a] Based on the ROC value of May 2016 (52.40 Euros).
[b] Cost associated with 34% efficiency power stations, and market prices (coal, EUA, wood pellets) of May 2016.

(which are based on fossil fuel sources) and the electricity cost from RESs.[5] The scheme works with multiple bidding phases (nine in 2015 and four in 2016), with a budget cap and a maximal premium for each technology and phase. Each bidder submits a (bid) premium (lower than the maximal) and a level of output. For each technology, the auction continues until the budget is reached. Bidders with the lowest bids are served first, and they receive the premium they bid. In the co-firing category, producers can bid for a maximum premium of 107 Euros/MWh_{elec} for a period of eight years (Netherlands Enterprise Agency, 2016; AURES-Ecofys, 2016).

During the 2016 auctions, co-firing units were among the biggest winners. For example, in the first phase of July, several coal stations received around 1.5 billion Euros to co-fire up to

5. For readers familiar with the earlier application of emission trading in the UK (the so-called UK ETS), the design is similar, with participants bidding for premiums that cover increased costs associated with efforts (increased RES generation with the SDE+ and carbon abatements in the case of the UK ETS).

50 percent biomass for a total SDE+ budget of 8 billion Euros in 2016. However, whether these subsidies for co-firing will actually be implemented or not remains uncertain because of the Dutch government's plans to close all coal stations by 2020, which are still under debate.[6]

In the context of our paper, we choose to focus on France and Germany rather than directly considering those countries with RES supports given to co-firing. These two countries offer useful cases for our analysis because they have substantial coal capacities and no subsidy for co-firing, meaning they provide relevant counterfactuals with which to investigate the consequences of implementing such provisions for co-firing in RES support schemes.

Plainly Germany uses a far larger proportion of coal for electricity generation than France. However, even though coal makes up a rather small share of French electricity, the associated volumes are quite significant compared with other European countries in which coal is known as an important source of electricity (Table 3)

Table 3: Coal in the 2010 European electricity (Eurelectric, 2011).

	Germany	Poland	UK	Denmark	France	Netherlands	Greece	Belgium
Coal power capacity[a]	55 547	34 305	28 068	9 272	8 153	5 641	4 744	1 156
	(29%)	(86%)	(28%)	(42%)	(6%)	(14%)	(29%)	(6%)
Coal power generation	262.4	154	102.9	27	19.8	27.1	27.5	6.2
	(38%)	(87%)	(26%)	(42%)	(4%)	(15%)	(49%)	(6%)

[a] Countries are ranked from left to right by increasing coal capacities.

3. SIMULATION METHODOLOGY

3.1 The economics of co-firing: A literature overview

The economic literature about co-firing mainly relies on three approaches: Estimations of technical potential given by existing fleets in electricity (Berggren et al., 2008; Hansson et al., 2009; Bertrand et al., 2014), calculations for profitability of co-firing depending on representative market conditions (Bertrand et al., 2014; Xian et al., 2015; Mei and Wetzstein, 2017), and theoretical framework with stylized power system (Lintunen and Kangas, 2010).[7]

Among the papers that investigate the technical potential of co-firing (i.e. the question of how much biomass can be used in co-firing and electricity, and the related CO_2 abatements), Berggren et al. (2008) focuses on matching the potential biomass supply in Poland with estimated opportunities for biomass co-firing in the existing Polish coal plants. The authors also derive the CO_2 abatements from co-firing. Results indicate that about 4 Mt of CO_2 can be abated each year in Poland through biomass co-firing. Hansson et al. (2009) estimate the potential power generation from co-firing in the existing European coal plants. They report that co-firing can generate yearly electricity production from 50 to 90 TWh_{elec} in the EU-27. However, as opposed to Berggren et al. (2008) for Poland, the authors do not provide comparisons of their results with the potential biomass supply, and they do not compute the CO_2 abatements from co-firing. Bertrand et al. (2014) extend these works by estimating the potential biomass demand from both co-firing and dedicated biomass

6. www.argusmedia.com

7. One may also mention here the contributions by Linden et al. (2013), and Sands et al. (2014), which consider co-firing among other options to investigate the substitution between fossil and non-fossil fuels in the Finnish power system (Linden et al., 2013), and the effect of bio-electricity with other power technologies for the carbon balance between mitigation and land use (Sands et al., 2014). However, since co-firing is not the focus of these papers (but rather a secondary question that is not analyzed alone), we do not discuss them in detail in this literature review.

power plants in the EU-27, and they compare the results with the potential biomass feedstocks in Europe. Moreover, the authors also compute CO_2 abatements associated with co-firing. Results show that co-firing offers the highest potential demand in electricity with up to 80 percent of the overall potential demand from power. Additionally, depending on the assumptions on co-firing and biomass availability in Europe, the EU-27 potential demand is found to account for 8 to 148 percent of the European potential supply. Regarding CO_2 emissions, results indicate that implementing co-firing in existing coal plants can produce high volumes of abatements, with a maximal potential estimated to be around 360 Mt of CO_2 per year in the EU-27.

A second strand of literature focuses on estimating the profitability of co-firing depending on market conditions. Bertrand et al. (2014) compute the biomass and CO_2 breakeven prices for co-firing in the European context with carbon pricing through the EU ETS. These values reflect the economic conditions that make co-firing profitable depending on prices for coal, biomass and CO_2. Results indicate that co-firing is profitable with a biomass price that is in the range of 16 to 24 (25 to 35, respectively) Euros per MWh_{prim} when the carbon price is 20 (50, respectively) Euros per tonne of CO_2. Another contribution comes from Xian et al. (2015) and Mei and Wetzstein (2017), who analyze the competitiveness of co-firing for coal plants in Georgia, United States, over the period 2009–2014. Results demonstrate that co-firing is not a profitable option under the current US market conditions, with free carbon emissions and competition of low-cost shale gas. Hence, the government must implement incentive schemes if the development of co-firing is an objective. The timing of policy also matters, with early incentives needed to avoid adoption of alternative energies through shale gas. The authors conclude that a subsidy of 1.40 US Dollars per MMBTU on co-fired biomass or a tax of 1.50 US Dollars per MMBTU on coal would be needed to trigger the development of co-firing in the United States. Given an average cost of 0.12 US Dollars per kWh_{elec} for electricity in the United States, this would represent about 4 percent of the electricity cost.[8]

A last contribution to the economics of co-firing comes from Lintunen and Kangas (2010), and it provides a theoretical framework in which to analyze the effect of co-firing in a stylized and simplified power system. Their paper aims to assess the effect for investments in pure renewable electricity plants and CO_2 emissions when promoting co-firing as a renewable option. The authors consider profit maximizing power producers that optimize production and investment decisions so as to meet static power demand over different sub-periods reflecting load profile. The model considers exogenous hydro and nuclear power generation, so that the decisions satisfies only the residual demand that is left to other technologies. Investments in renewables rely on wind turbines only, and all other renewable technologies are excluded from the analysis. In this case, investment decisions are modeled as demand for new wind turbines that can increase the production capacity with the aim of meeting the static power demand at the lowest cost. The authors provide a numerical application with parameters reflecting the Finnish power sector. Results show that promoting co-firing as a renewable decreases investments in pure renewable technology, whereas the CO_2 intensity of electricity is barely impacted. Given the qualitative shape of results regarding investments in renewables, it is very likely that a more general treatment of the power sector (with a dynamic time horizon, the decommissioning of old capacities, rising demand for power, increasing renewable targets, etc.) may modify the impact for CO_2 emissions when co-firing is considered as a renewable. This is the starting point of our analysis with the GES model.

Compared with the aforementioned literature, the GES model is an electricity simulation model that considers a detailed representation of power system and co-firing based on actual data

8. Another recent paper by Strauss (2017) estimates that the US government has to compensate the generators of co-fired electricity with a subsidy of about 0.007 US Dollars per kWh_{elec} so as to render co-firing competitive.

rather than representative situations.[9] This can be used to investigate the effects associated with co-firing from a more accurate perspective, when considering possible evolutions of policy and other energy-related decisions over time. Hence, the GES model offers a flexible tool for analyzing the effect of co-firing in combination with policy scenarios and other real problems that apply to the power sector.

3.2 Model description

GES is a dynamic simulation model that is designed to investigate questions related to biomass-based electricity in European countries, with a special focus on biomass co-firing in coal plants. The model minimizes the overall cost of electricity (generation and investment), over the 2010–2030 time interval with a range of economic, technical, and legal constraints: capacity (generation ≤ available capacity), market clearing for electricity, share of RES in power generation, physical constraints associated with co-firing (loss in efficiency of coal plants and percentage of biomass that can be co-fired depending on the resource quality), etc. In this work, we use the French and the German modules from the 1.0 version (Bertrand and Le Cadre, 2015). Extensive documentation on the model is provided as supplementary materials (see Appendix A).

For each year in the considered time interval, the model determines the power generation mix (based on a merit order logic) and investment decisions so as to meet electricity demand at the least cost. It computes the optimal dispatch of generating capacities into intra-annual hourly time slices with unequal power demand. This reflects different load levels associated with more or less electricity demand.

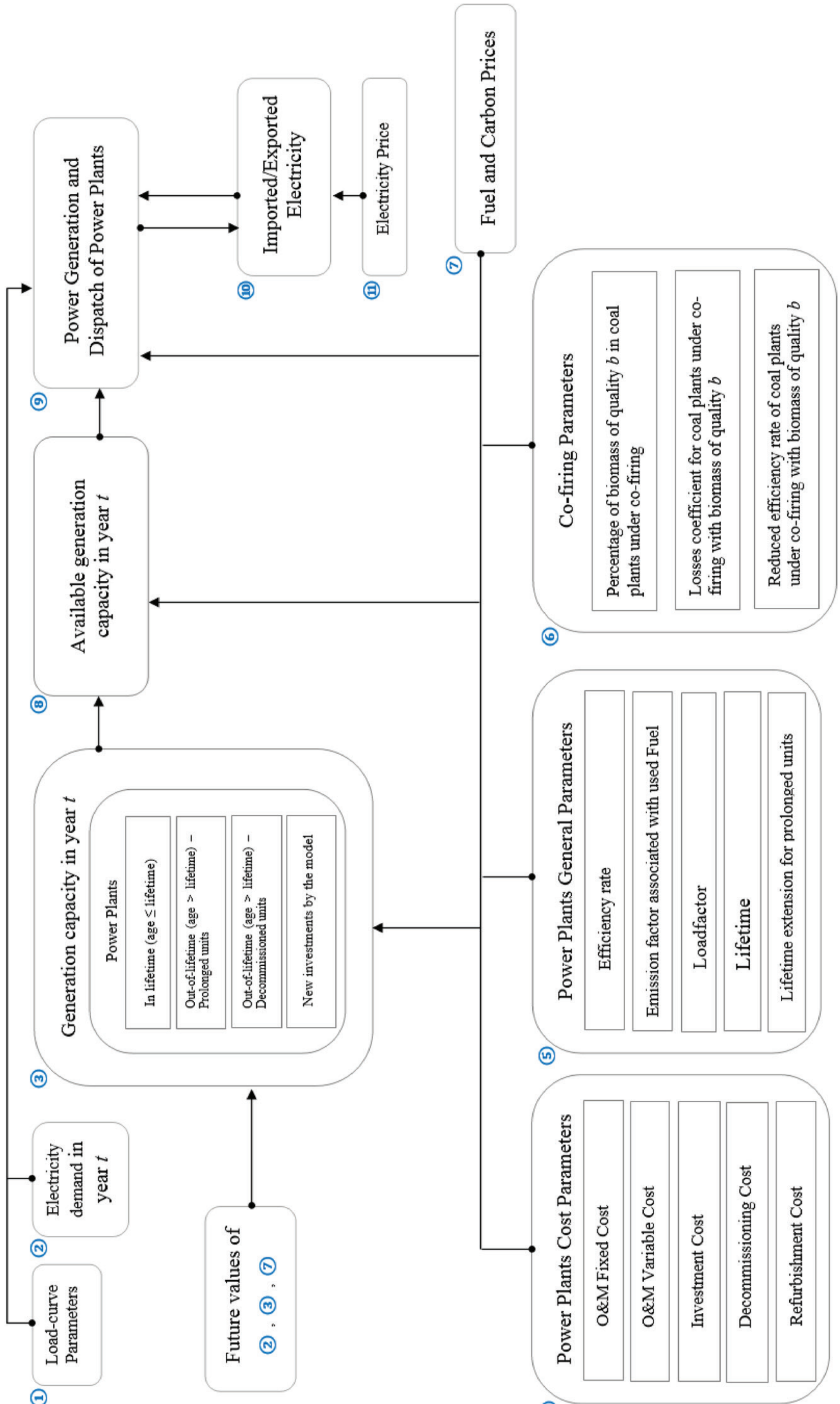
The modeling framework can also be used to investigate the consequences of modifications in generating capacities through investments in new power stations and decisions regarding decommissioning or prolongation of old units that have exceeded their theoretical lifetime.[10] Hence, the structure of the fleet is made flexible, allowing any change in the electricity mix in favor of biomass to be analyzed with a degree of flexibility that depends on relative prices and technological and legal aspects. Figure 1 provides an overview of the model framework.

Investments mainly rely on comparisons between the LLCOEs of different power technologies, which evolve through time with the price trends for fuels and carbon. However, as a simplification, we assume that the cost and technical parameters (see section 3.3) remain constant throughout the time interval (but the cost parameters are still subject to discounting). As a consequence, the modeling does not consider the effect of technological progress, which may reduce the cost

9. Electricity simulation models or electricity models refer to models that simulate power generation and investment decisions in electricity, based on actual data rather than representative situations as in theoretical approaches. Many electricity models have been developed to simulate the impact of different scenarios for energy and environmental policy. Among those contributions, some have focused on questions around biomass-based electricity, but they neglect biomass co-firing in coal plants (Santisirisomboon et al., 2001; Rentizelas et al., 2012). To the best of our knowledge, the GES model is the only electricity model that is primarily designed to analyze questions related to co-firing. See Kannan and Turton (2013) and Rentizelas et al. (2012) for a literature review on electricity models.

10. At the beginning of each year, the model identifies which are the out-of-lifetime power plants (i.e. age > theoretical lifetime). Once the set of out-of-lifetime power plants has been identified, the model implements calculations for each unit in this set, so it can be determined whether it is a profitable option to refurbish and extend the life of those units, or whether it is cheaper to decommission them and consider new investments. The calculation relies on comparing the Levelized Lifetime Costs of Electricity (LLCOE) associated with new or prolonged units. In the case of coal plants, this calculation can be implemented by taking into account the ability to co-fire coal with biomass or not. See supplementary materials from Appendix A for the complete mathematical formulation of the model.

Figure 1: Overview of the GES optimization problem.



of investing in renewable technologies compared with others as time goes on.[11] Technically, such investigations may be implemented by applying learning rates to the cost parameters. In this case, a well-sound analysis would need to run a sensibility analysis on the learning rate coefficients, which are themselves subject to uncertainties and are likely to evolve over time. Since our focus is on the prospective analysis of policies around the treatment of co-firing, we choose not to investigate such evolutions of cost parameters, which would multiply the number of scenarios to consider. Hence, we neglect the effect of technological progress in order to keep the prospective analysis of policies more compact so as to make the results more tractable. Predictably, a likely consequence of dropping this assumption is that renewable technologies will gain in profitability thanks to technological progress, which would increase investments in these technologies, *ceteris paribus*, and reduce the magnitude of the crowding-out effect (replacement of traditional RESs by co-firing) with lesser induced effects. This would not invalidate our analysis, but just diminish the magnitude of the results.

3.3 Data and model calibration

The dataset for the power system is based on a literature review providing representative values for cost and technical parameters associated with different power technologies of varying vintages: efficiency rates of power plants, load-factors, fixed and variable operation and maintenance costs, refurbishment costs, decommissioning costs, theoretical lifetimes (depending on whether stations have been prolonged or not), etc.[12]

In order to derive realistic projections, the model has been calibrated to actual market data for the base year (i.e. 2010). We focused on reproducing the observed yearly generation by fuel through iterative adjustments of availability and marginal costs so as to best replicate the French and German power generation mix as given by (RTE, 2011) and Eurelectric (2011). Such model calibration is a standard exercise in simulation, which is necessary to avoid simulation results departing too much from actual data. In particular, as pointed out in previous studies, simulations relying on unadjusted models are likely to generate errors in estimations derived from uncorrected power generation. For instance, estimating CO_2 emissions based on (simulated) uncorrected power generation can lead to significant bias in abatement estimates due to divergences in the utilization of power technologies with varying carbon intensity compared with real world responses under similar conditions (Delarue et al., 2010; Weigt et al., 2013; Solier, 2014).

Coal (bituminous), gas, oil, and carbon prices are based on the Current Policy Scenario (CPS) from IEA (2012) and other fuel prices are derived from the literature review. In all cases, the model considers price trends that are indexed on the Average Annual Growth Rates (AAGR) from the IEA-CPS scenario as well as other projections (from different references) reflecting specific evolutions in other fuel industries (uranium, lignite, solid biomass, biogas, bio-liquids, and mixed grade waste).[13]

The annual electricity demand is obtained from the 2010 ENTSO-E values to which we apply the AAGR from the IEA-CPS scenario to compute projections over the time interval.[14] The

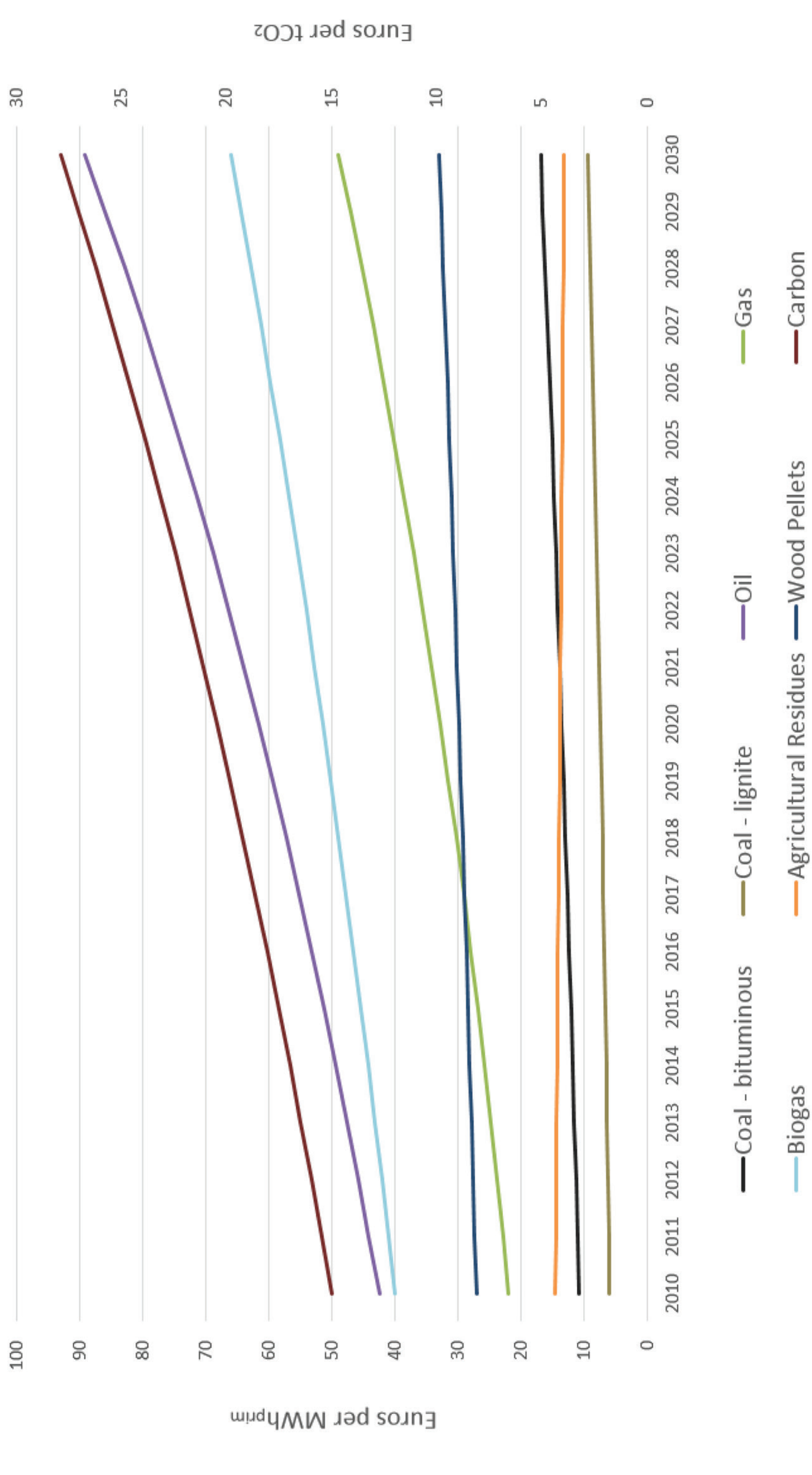
11. In general, investment costs for renewables have been considerably reduced during the last few years, and this process is likely to continue in the future. This may impact our analysis, and this would merit closer investigation in further studies. Nevertheless, even if the cost to invest in renewables is drastically reduced, this would still be possible to get support from renewable schemes with co-firing, without implementing any investment. Hence, it is still possible to replace traditional RESs (which require investment) by co-firing (which needs no investment) in order to obtain subsidies.

12. See Appendix A.

13. See Appendix A.

14. See Power Statistics on www.entsoe.eu.

Figure 2: Main fuel and carbon prices.



resulting yearly demands are then disaggregated on hourly levels, using weighting coefficients reflecting intra-annual time slices of varying length and power load (Bertrand and Le Cadre, 2015).

Regarding the installed capacities for power plants, the model uses data from the World Electric Power Plants (WEPP) data base by Platts, which provides a global inventory of electric power stations with information such as location, year of commissioning, size, etc. In the case of Germany, the data has been completed with a listing of planned nuclear decommissioning to account for the 2011 decision by the German government to shut down all the country's nuclear power plants by 2022 (Appendix B). This allows us to include exogenous reduction of nuclear capacity in the data for the model in line with the German nuclear phase-out plan. In order to investigate the effect of reductions in French nuclear capacity (in line with the French nuclear strategy enacted by France's energy transition law of 2015), we have included an additional constraint in the model that proscribes prolongation of out-of-lifetime nuclear power stations. This is equivalent to exogenous decommissioning of old nuclear power plants.

3.4 RES OBLIGATIONS AND CO-FIRING

In order to investigate the question of how co-firing may impact the electricity mix if it is recognized as an RES, we run simulations with and without co-firing in the set of RES technologies that are accounted for to meet the RES targets. As a simplification, we assume that only the biomass part from the primary energy in coal plants is accounted for as an RES. Hence, we run the model by considering either equation **(1a)** or **(2a)**, depending on whether co-firing is included or not in the set of RESs:

$$\sum_{u \in URES} P^i_{t,u} \geq \tau^i_{2020} \times \left(\sum_{u \in U} P^i_{t,u} \right), \tag{1a}$$

$$\sum_{u \in URES} P^i_{t,u} + \sum_{u \in UC} \sum_{b \in FSB} \left(\eta^{cf}_{u,b} F^i_{t,u,b} \right) \geq \tau^i_{2020} \times \left(\sum_{u \in U} P^i_{t,u} \right), \tag{2a}$$

where $P^i_{t,u}$ stands for power generation from unit *u* in country $i \in [France, Germany]$ during year *t*, $\forall t \in [2020, \ldots, 2030]$. τ^i_{2020} is the 2020 RES target of country *i* (percentage of RESs in overall power generation, see Table 4). U is the set of all power technologies, and FSB represents the set of all solid biomass fuels of varying quality. UC and $URES$ stand for the sets of coal and RES units, with $UC \subset U$ and $URES \subset U$. In **(2a)**, when co-firing is counted as a RES, $F^i_{t,u,b}$ represents the quantity of solid biomass *b* that is included in coal plants $u \in UC$ under co-firing. $\eta^{cf}_{u,b}$ is the reduced efficiency rate of coal plants $u \in UC$ under co-firing (cf) due to loss in combustion efficiency with biomass (increased moisture content and presence of air). In this case, $\eta^{cf}_{u,b} < \eta^{nocf}_{u}$, where η^{nocf}_{u} is the efficiency rate of coal plants under the classical configuration when coal is the only input.[15]

In order to consider the 2030 targets, in addition to those of 2020, we add **(1b)** to **(1a)** or **(2b)** to **(2a)**:

15. The model considers different types of solid biomass with varying quality: agricultural residues (AR), wood chips (WC), wood pellets (WP), and torrefied biomass pellets (TOP). The higher the quality (AR quality < WC quality < WP quality < TOP quality), the higher the percentage of biomass (that can be included in coal plants). Moreover, for a given percentage of biomass, the actual reduction in the efficiency rate depends on the type of biomass, based on a loss coefficient that increases when the biomass quality is reduced. Hence, for a given percentage of biomass, $\eta^{cf}_{u,AR} < \eta^{cf}_{u,WC} < \eta^{cf}_{u,WP} < \eta^{cf}_{u,TOP}$. See supplementary materials from Appendix A.

Table 4: 2020 and 2030 RES targets for power generation in France and Germany (BMWi, 2015; CGDD, 2015). The values are expressed in percentage of the 2020/2030 overall power generation.

	2020	2030
France	$\tau_{2020}^{France} = 27\%$	$\tau_{2030}^{France} = 40\%$
Germany	$\tau_{2020}^{Germany} = 35\%$	$\tau_{2030}^{Germany} = 50\%$

$$\sum_{u \in URES} P_{2030,u}^{i} \geq \tau_{2030}^{i} \times \left(\sum_{u \in U} P_{2030,u}^{i} \right), \quad \textbf{(1b)}$$

$$\sum_{u \in URES} P_{2030,u}^{i} + \sum_{u \in UC} \sum_{b \in FSB} \left(\eta_{u,b}^{cf} F_{2030,u,b}^{i} \right) \geq \tau_{2030}^{i} \times \left(\sum_{u \in U} P_{2030,u}^{i} \right). \quad \textbf{(2b)}$$

4. RESULTS AND DISCUSSIONS

4.1 Implications for the electricity mix

Results confirm that recognizing co-firing as an RES may greatly modify the electricity mix, whatever the country.[16] We observe an increased contribution from coal when co-firing is counted as an RES (*co-firing in RES*) compared with when it is not (*co-firing out RES*). Figures 3, 4, and 5 indicate that when co-firing is included in the set of RES technologies, the RES capacity remains constant so investments in traditional RESs disappear compared with the situation in which co-firing is considered a non-renewable option.

Increased coal-based generation is more significant in Germany due to its greater coal capacity (Figure 6). There are also some new investments in coal when co-firing is included in the set of RESs (Appendix C). Even though the existing German coal capacity is already very high, it appears that it is not large enough to offset the reduced investments in traditional RESs to meet the RES targets through co-firing. The new coal investments vanish when co-firing is excluded from the set of RESs. In France, existing coal capacities are lower than in Germany (approx. 7.5 GW for the French initial coal capacities against 51.2 GW in Germany), on the one hand, but the RES targets are less significant, on the other hand (Table 4). This translates into two counteracting effects for the need to invest in new coal stations, with French coal capacities that are too small to allow substantial co-firing to meet the RES obligations, but RES targets that are also lower than in Germany (which reduces the need for coal stations to co-fire biomass). The actual effect also depends on the share of nuclear electricity and the resulting need for conventional capacities, such as coal, to fill the nuclear power gap. Overall, when the prolongation of out-of-lifetime nuclear plants is not allowed and co-firing is included in the set of RESs, the increased coal contribution is maximal (Figures 6), which translates into more investments in new coal stations (Appendix C). In this case, the additional French coal capacities may reach up to 18 GW, whereas these investments disappear when old nuclear power stations are maintained in service and co-firing is excluded from the set of RESs. Comparatively, the maximal additional coal capacity in Germany is close to 14 GW when co-firing is included in the set of RESs. In this case, the 2030 German capacity mix exhibits a progression

16. To save space, we only report the results associated with implementation of the model with both the 2020 and the 2030 constraints for the RES targets (i.e. **(1a)** with **(1b)** or **(2a)** with **(2b)**). Alternative settings do not qualitatively modify results. Additional results are available upon request.

Figure 3: Evolution of the German capacity mix (all technologies, left panel; RES technologies, right panel), depending on whether, or not, co-firing is included in the set of RES technology that are accounted for to meet the RES targets.

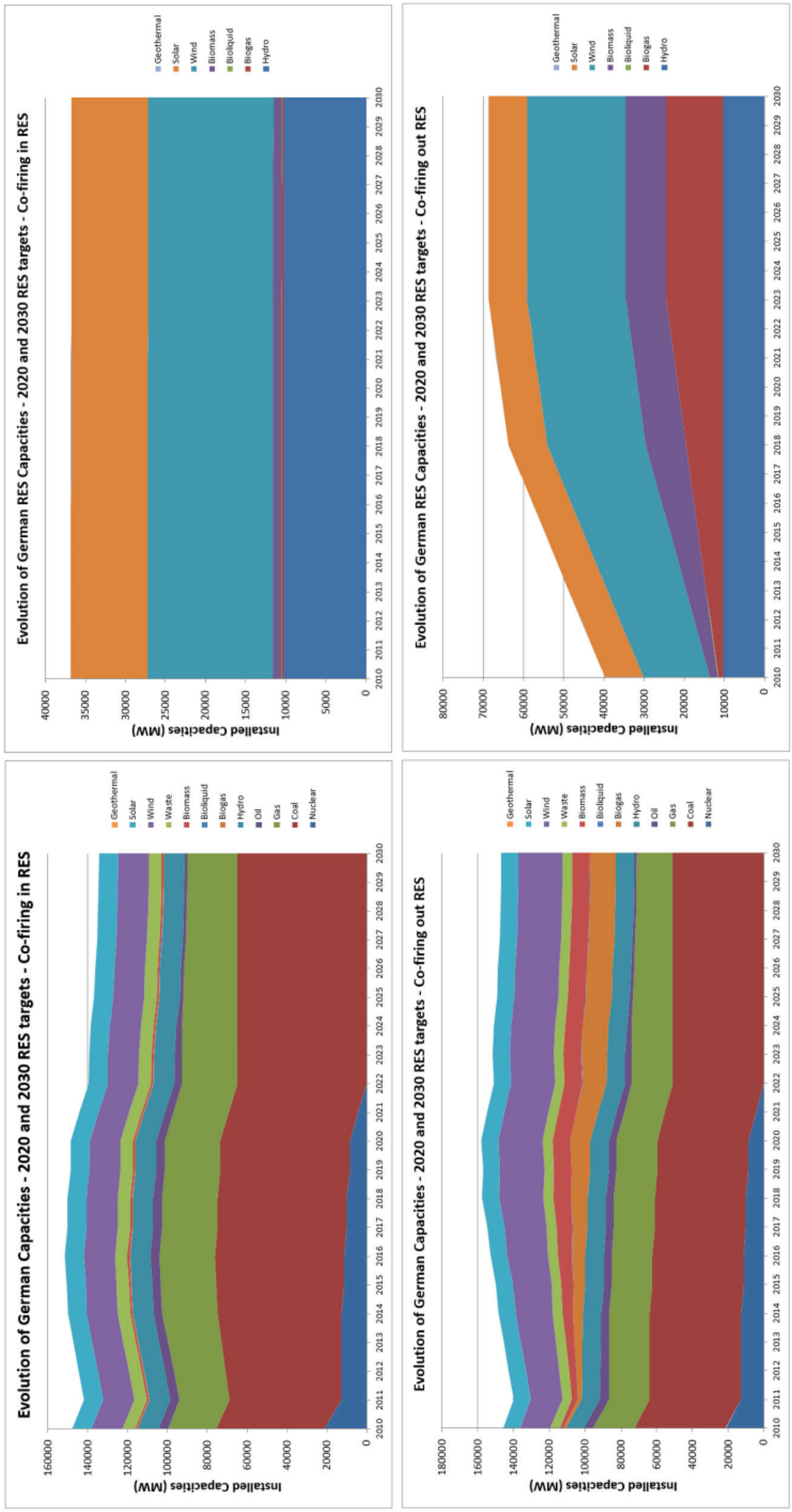


Figure 4: Evolution of the French capacity mix (all technologies, left panel; RES technologies, right panel) with exogenous decommissioning of out-of-lifetime nuclear units, depending on whether, or not, co-firing is included in the set of RES technology that are accounted for to meet the RES targets.

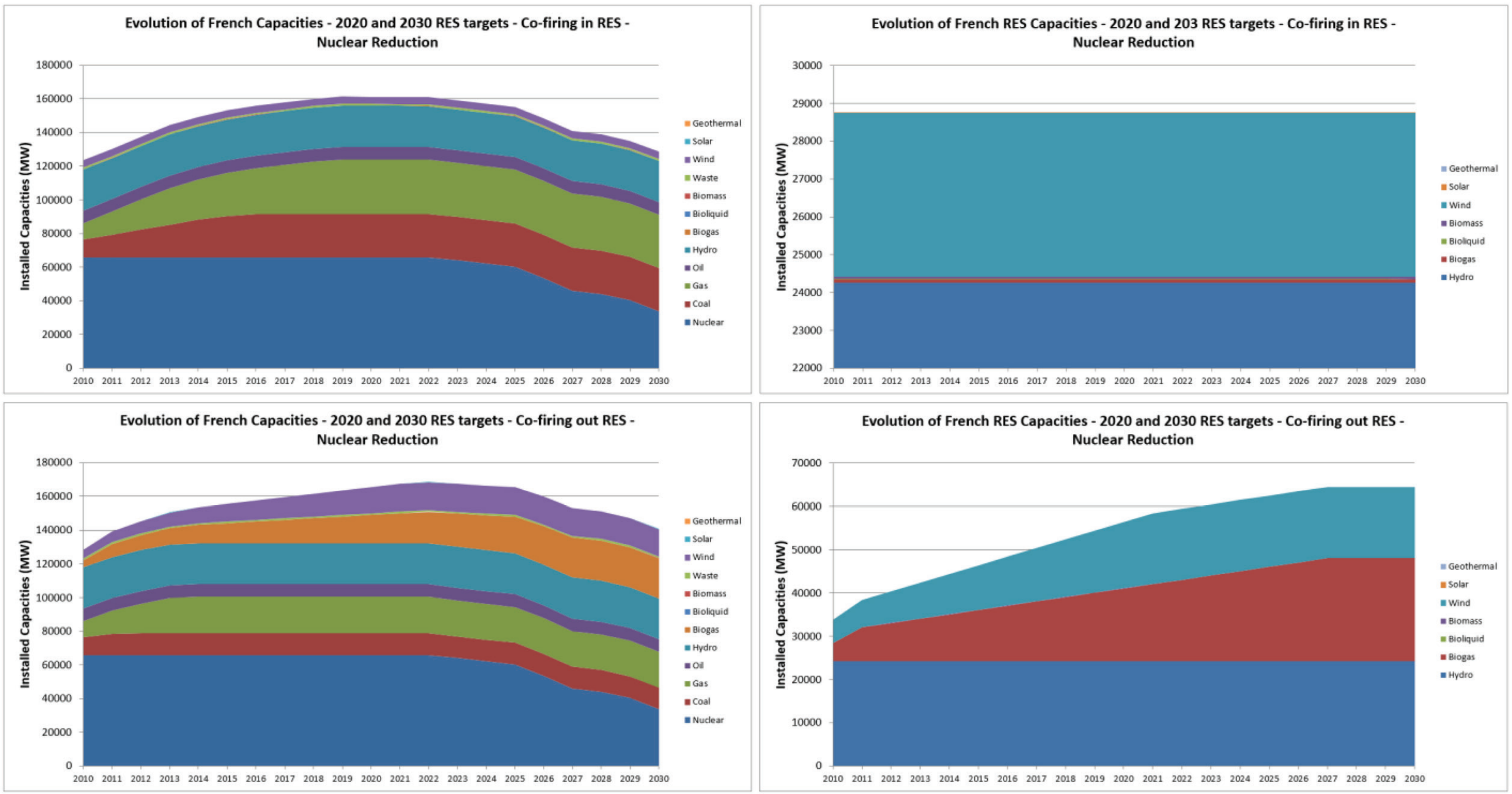


Figure 5: Evolution of the French capacity mix (all technologies, left panel; RES technologies, right panel) with endogenous prolongation of out-of-lifetime nuclear units, depending on whether, or not, co-firing is included in the set of RES technology that are accounted for to meet the RES targets.

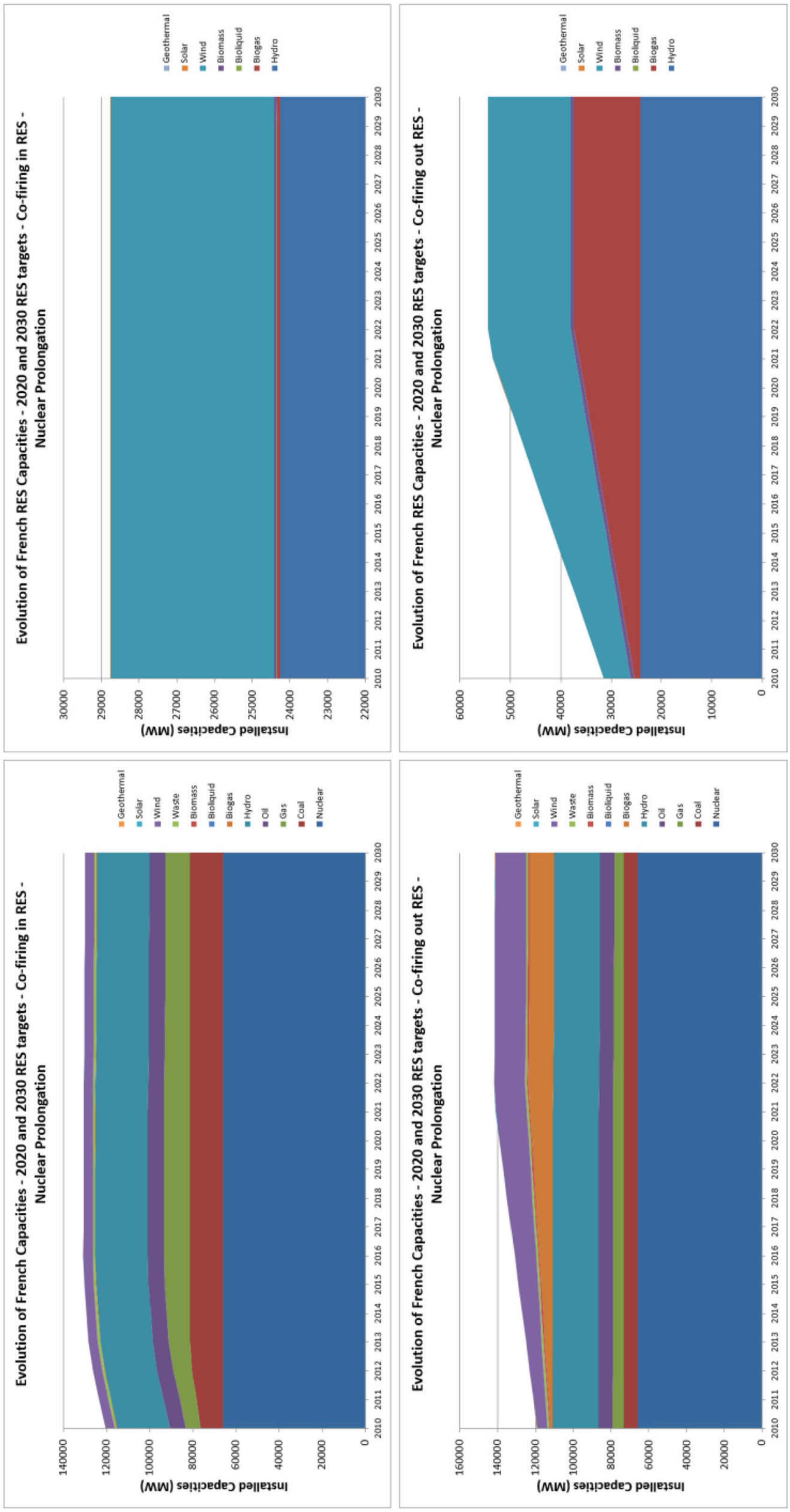
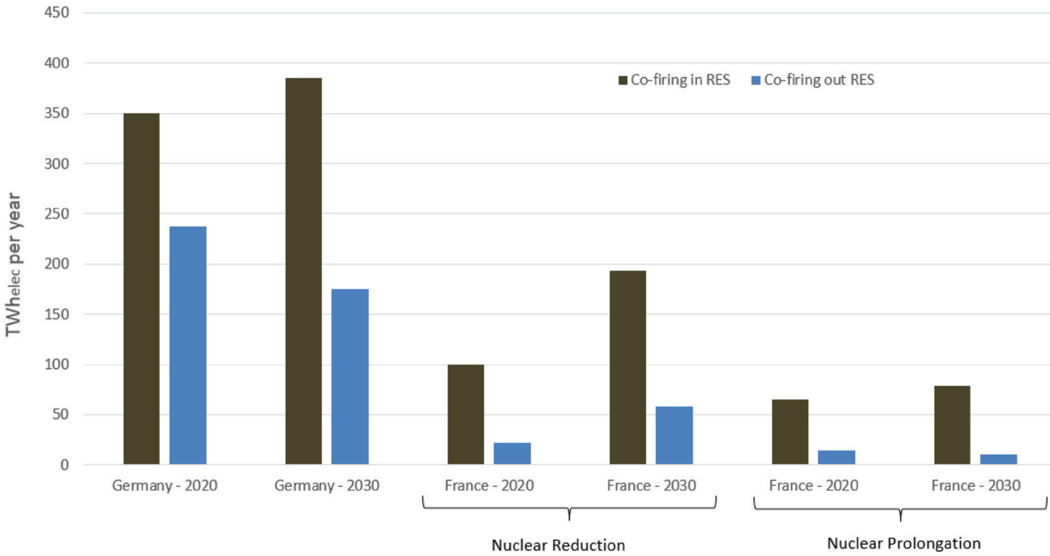


Figure 6: Coal-based power generation (hard-coal and lignite) in France and Germany depending on the treatment co-firing regarding the RES targets.



of about 27% for coal compared with initial capacity (with 65 GW of coal in 2030, accounting for 48% of the capacity mix), whereas the same progression is more than 243% in France when old nuclear power stations are decommissioned, with almost 26 GW of coal accounting for 20% of the 2030 capacity mix (compared with 5% when old nuclear power stations are kept on and co-firing is excluded from RESs).[17] That is, although including co-firing in RESs would merely make German electricity still more dependent on coal, it might more radically modify the French capacity mix, in which coal may change status and become an important source of French electricity.

Figures 3, 4, and 5 show that when co-firing is omitted from the set of RESs, investments in traditional RESs (to meet the mandatory obligations) mainly benefit biogas, wind, and dedicated biomass. First, investments in biogas and dedicated biomass appear to be an interesting option because they are competitive RES technologies that are not subject to the same drawbacks as other RESs with low availability. In the case of wind, the drawback of low availability is outweighed by a low investment cost with zero marginal cost, so that it remains a competitive option.[18] Second, investing in biogas and dedicated biomass meets the need for new conventional generation capacities with German nuclear phasing-out, exogenous decommissioning of France's old nuclear power stations, and substantial endogenous decommissioning of out-of-lifetime German combined-cycle units (Figure 10 in Appendix D).[19] Biogas and dedicated biomass offer interesting characteristics in this context, because they are RES technologies with high availability as conventional units.

17. When old nuclear power stations are kept on and co-firing is in the set of RES, the French coal capacity increases by 107% in 2030 compared with initial capacity, with about 15.5 GW of coal accounting for 12% of the 2030 capacity mix. Here again a surge occurs.

18. The competitiveness of biogas, wind, and dedicated biomass is illustrated by the levelized lifetime cost of electricity (LLCOE) in Appendix D.

19. It appears that prolonging old combined cycle (gas or oil) is not a profitable option because investing in new fashion units is not very costly (e.g. at half of the cost of investing in a comparable new coal plant), and it provides a greater increase in the efficiency rate than competing technologies.

In the case of Germany, the rapid decline in conventional capacities with nuclear phasing-out and decommissioning of old combined-cycle units as of 2012 is creating an early need for new dispatchable units from the very beginning of the time horizon. This, combined with higher German RES targets, favors more investments in dedicated biomass than in France. Because the model considers an upper limit for new investments that can be implemented during a year in each technology, new capacities have to be directed more towards dedicated biomass in Germany, early in the time horizon (when considering the RESs with high availability, dedicated biomass is the second best technology after biogas at the beginning of the time horizon, see Figure 11 in Appendix D), once the investment potential for biogas has been exhausted.[20]

4.2 Implications for CO_2 emissions and electricity cost

All the results above indicate that, if co-firing is included in support schemes for renewable electricity, coal would crowd-out traditional RESs, not only with increased generation from existing coal plants but also with additional investments in coal that would be substituted for wind, dedicated biomass, biogas, and other traditional RESs. This may raise political and economic issues in the long run among populations concerned about tackling climate change effects and reducing the share of polluting fossil fuels in the energy mix.

Figure 7: CO_2 emissions from power generation in France and Germany depending on the treatment co-firing regarding the RES targets.

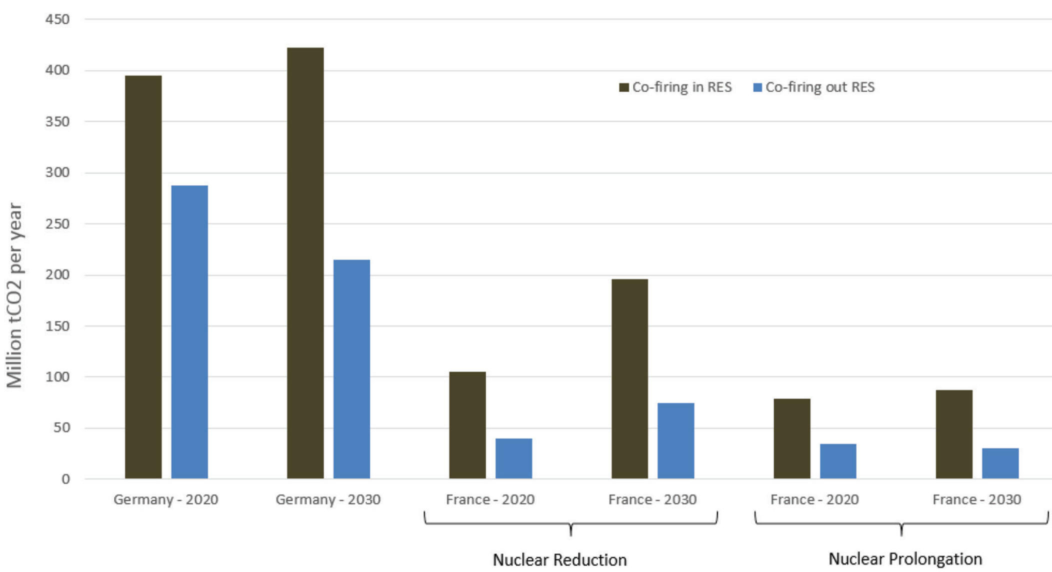


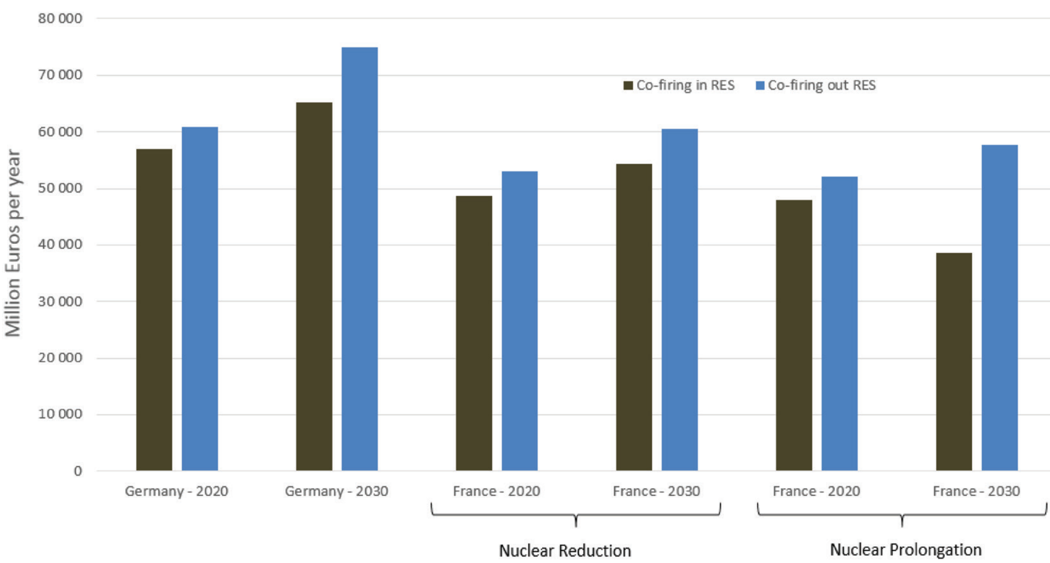
Figure 7 shows that recognizing co-firing as an RES generates sharp increases of CO_2 emissions due to reduced traditional RESs (carbon-free) and more coal in the electricity mix. As illustrated in Figure 6, including co-firing in the set of RESs produces a much larger increase in coal-based generation in the case of Germany due to its much greater coal capacities. This translates into

20. Setting such per technology maximal amounts for yearly investments is a common assumption in simulation models for electricity (e.g. Rentzelas et al., 2012; Kannan and Turton, 2013). This reflects real-world constraints and avoids unrealistic situations in which power generation would rely on a single or very few technologies due to massive investments.

a more significant increase of CO_2 emissions in Germany than in France (Figure 7). Although coal plants are mainly used under co-firing in this case, substituting coal with reduced emissions for carbon-free RESs inevitably increases CO_2 emissions. In France, the effect on CO_2 emissions depends largely on the share of nuclear power in electricity. When it is not allowed to keep out-of-lifetime nuclear plants in service and when co-firing is included in the set of RESs, the large increased contribution from coal (Figures 6), which is substituted for carbon-free RESs and nuclear power, causes a very significant increase in CO_2 emissions (Figure 7).

From a more policy-oriented point of view, the increased CO_2 emissions when recognizing co-firing as an RES should be balanced against the associated cost saving in the electricity sector, which may reduce the cost of policies to achieve objectives for renewable electricity. In order to bring the cost savings out, Figure 8 depicts the overall annual costs associated with managing the power system (generation, investments, prolongations, provisions, etc.) so as to meet electricity demand at the lowest cost. Unsurprisingly, Figure 8 shows that including co-firing in the set of RESs reduces the overall electricity cost in all the situations considered, because this means the RES constraint can be complied with through a conventional and low-cost option, which does not require additional investments for coal plants from existing capacities. For France, the highest cost reduction associated with recognizing co-firing as an RES occurs when the out-of-lifetime nuclear power stations are kept on. In this case, the nuclear plants continue to generate base-load electricity because they are the cheapest conventional technology. The increased coal generation (under co-firing) is essentially located in higher load levels, where it competes with technologies that are less cost effective than nuclear power. Hence, co-firing can reduce the cost of complying with the RES constraint without increasing the cost in base-load because nuclear power is still predominant in this generation segment.[21] By contrast, when prolongation of nuclear power is not allowed, increased

Figure 8: Overall electricity cost to meet annual power demand in France and Germany depending on the treatment co-firing regarding the RES targets.



21. For the same reasons, recognizing co-firing as an RES increases CO_2 emissions more when nuclear power plants are decommissioned. In this case, coal under co-firing is substituted for nuclear power in base-load, thereby emitting more CO_2 than when nuclear plants are kept on to generate base-load and co-firing is implemented for higher load-levels (Figure 7).

coal generation is mainly substituted for nuclear plants, which entails a substantial cost increase in base-load generation even if the cost of complying with the RES constraint is reduced.

A more comprehensive comparison should consider the increased carbon cost for society when recognizing co-firing as an RES. On the one hand, any cost saving due to including co-firing in the set of RESs may reduce the cost of policies to attain objectives for renewable electricity. On the other hand, if this also entails a rise in CO_2 emissions, one should consider the associated increase in the carbon cost so as to evaluate the actual benefit for society. In order to run this comparison, we evaluate the increased carbon cost (based on increased emissions corresponding to the difference between values associated with co-firing *in* and *out* RES in Figure 7) using a series of valuations for CO_2 emissions reflecting different assumptions about the Social Cost of Carbon (SCC). Meanwhile, the carbon cost that is paid by the power sector is still included in the overall electricity cost, and it relies on the price data for CO_2 presented in section 3.2.

Nordhaus (2017) provides values for the SCC of 2030 that reflect the emission path with current policies depending on different discount rates. The SCC is in a range of 30 to 165 US Dollars of 2010, which approximately equates to 20 to 130 Euros.[22] Accordingly, we consider the following valuations for estimating the increased carbon cost for society: 20, 30, 100, and 130 Euros per tCO_2. The computed carbon costs are compared with the overall cost savings in electricity, which corresponds to the difference between values associated with co-firing *in* and *out* RES in Figure 8. Results are presented in Figure 9.

Figure 9: Overall electricity cost saving versus increased carbon cost (with 20, 30, 100 and 130 Euros SCC) when co-firing is included in the set of RES.

As illustrated in Figure 9, the cost saving from including co-firing in RESs dominates the increased carbon cost when the SCC is low (20 and 30 Euros per tCO_2), whereas the opposite occurs with higher SCC (100 and 130 Euros per tCO_2). An exception is found for France when the out-of-lifetime nuclear power stations are prolonged. In this case, the cost saving is very high and the increased CO_2 emissions are slight (see discussions above) with the result that the cost saving invariably outweighs the increased carbon cost, whatever the SCC.

22. We used a representative EUR/USD exchange rate of 2010 (from ECB) to convert the values.

5. CONCLUSION

This paper explores the effect of recognizing co-firing coal with biomass as renewable electricity so as to meet the RES mandatory requirement. We provide simulations for the French and German electricity mix with investigations into the consequences for cost savings in the power sector and CO_2 emissions. We focus on France and Germany because they have substantial coal capacities and no support scheme for co-firing has been implemented in these countries so far. Hence, they are suitable cases for our analysis. The case of France is also useful for analyzing the effect of reduction in French nuclear power in combination with the RES targets. The resulting gap in the fleet of power plants is likely to be offset by some RES power plants, among which co-firing can contribute if counted as a renewable. This is something of interest for our study.

The question of consequences when promoting co-firing as renewable electricity has attracted little attention in the economic literature. To date, to the best of our knowledge, the only contribution comes from Lintunen and Kangas (2010), who provide a theoretical model to analyze the effect of co-firing in a stylized and simplified power system. Compared with this previous work, our paper uses a simulation approach to analyze the consequences for the electricity mix when co-firing is recognized as renewable electricity. We use the Green Electricity Simulate (GES) model, which is a simulation model for electricity designed to focus on biomass-based electricity and co-firing in European countries (Bertrand and Le Cadre, 2015). In order to assess the effect of promoting co-firing as a renewable option, we run the model with and without co-firing in the set of RES technologies that are accounted for to meet the RES targets. Our simulations rely on a detailed representation of the power system, which can be used to derive more general results taking into account elements such as a dynamic time horizon, the decommissioning of old capacities, rising demand for power or increasing renewable targets. This extends the study by Lintunen and Kangas (2010).

Results indicate that, if co-firing is recognized as an RES, coal would crowd-out traditional RESs not only with increased generation from existing coal plants but also with additional investments in coal that would be substituted for wind, dedicated biomass, biogas, and other traditional RESs. We find that the additional investments in coal may be more significant in France than in Germany because current French coal capacities are smaller than German capacities, limiting the possibility of using existing coal plants to meet the RES targets through co-firing. The additional coal capacities may attain a maximum of 18 GW in France (when the model is implemented with exogenous decommissioning of old nuclear power stations) against 14 GW in Germany. This corresponds to adding 27% of coal capacity in German electricity by 2030, whereas the same progression is more than 243% in France when old nuclear power stations are decommissioned (107% when the life of nuclear power plants is extended).

The analysis of CO_2 emissions reveals sharp increases when co-firing is recognized as an RES. Indeed, substituting coal for carbon-free RESs inevitably increases CO_2 emissions even if the emissions from coal are reduced through co-firing. The rise is more significant in Germany due to its greater coal capacities. In France, the magnitude of increased emissions depends largely on the share of nuclear electricity, with smaller increases when old nuclear power stations are kept in service. Finally, we find that including co-firing in the set of RESs reduces the overall costs associated with managing the power system because this allows compliance with the RES constraint through a conventional and low-cost option that does not require additional investments. We also offset the cost saving for the power sector against the increased social cost from higher CO_2 emissions in order to provide a more comprehensive evaluation of the actual benefit for society. Results show that the cost saving is dominated by the increased carbon cost for society if the carbon valuation is high (around

100 Euros per tCO_2, which is not an unusual value in studies evaluating the SCC), except in France when old nuclear power stations are prolonged (in this case, the cost saving is very high and the increased CO_2 emissions are slight, because coal competes higher in the merit order and base-load continues to be generated by massive cheap and carbon-free nuclear power).

Overall, our paper raises questions about the incentives to invest in traditional RESs if co-firing is recognized as a renewable. The consequences may be detrimental for the future energy mixes in European countries, with more coal (even if implemented under co-firing), fewer renewables, and resulting higher CO_2 emissions. The cost arising from adapting electricity to climate change is an important issue with populations that are increasingly concerned by this issue. As illustrated in the US presidential campaign, policy makers can also face complicated trade-offs between climate concerns and employment from the coal industry. [23] In this context, co-firing can be a useful option in the short run, but it can be risky in the long run if it jeopardizes a deeper transition towards more renewables and less carbon in energy. More generally, any policy that promotes co-firing against traditional renewables may result in higher CO_2 emissions in the long run, if it provides incentive to use coal plants under co-firing instead of investing in pure renewables. Whereas co-firing reduces the carbon intensity of coal plants, it still generates CO_2 emissions. Hence, if co-firing steadily displaces investments in traditional RESs over time, one may expect the CO_2 emissions from electricity to be higher in the long run (compared with a more far-reaching energy transition in which pure renewables dominate the fleet of power plants). This is something policy makers should remember when considering whether it is expedient to include provisions for co-firing in the support schemes for renewable electricity.

ACKNOWLEDGMENTS

This work is part of the Agriculture and Forestry research program by the Climate Economics Chair, Paris-Dauphine University. The author want to thank the Climate Economics Chair for financial support.

REFERENCES

Alexander, P., D. Moran, M.D.A. Rounsevell, and P. Smith (2013). "Modelling the perennial energy crop market: the role of spatial diffusion." *Journal of the Royal Society Interface* 10(88). https://doi.org/10.1098/rsif.2013.0656.

Argus (2016). Argus biomass markets. Issues 16-014.

AURES-Ecofys (2016). Auctions for Renewable Energy Support in the Netherlands: Instruments and lessons learnt.

Berggren, M., E. Ljunggren, and F. Johnsson (2008). "Biomass co-firing potentials for electricity generation in Poland - Matching supply and co-firing opportunities." *Biomass and Bioenergy* 32(9): 865–879. https://doi.org/10.1016/j.biombioe.2007.12.017.

Bertrand, V., B. Dequiedt, and E. Le Cadre (2014). "Biomass for Electricity in the EU-27: Potential Demand, CO_2 Abatements and Breakeven Prices for Co-firing." *Energy Policy* 73: 631–644. https://doi.org/10.1016/j.enpol.2014.06.007.

Bertrand, V. and E. Le Cadre (2015). "Simulating the use of biomass in electricity with the Green Electricty Simulate model: An application to the French power generation." CEC Working Paper, 2015-3.

Bubholz, M. and R. Nowakowski (2010). Mapping of subsidy systems and future consumption of biomass. Svensk Fjärrvärme, Technical Report.

23. In the case of the United States, Strauss (2017) proposes a strategy based on a policy that supports co-firing in US coal power plants, for the Trump administration to save the coal industry while creating new jobs for the forestry industry in states where pulp and paper mills are closing due to decline in the demand for paper. Additionally, CO_2 emissions from the US coal plants would be reduced, which is seen as a by-product of job protection. The author concludes that the strategy is "a win-win-win for the coal sector, the forest products sector, and for the environment".

BMWi (2015). The Energy of the Future – Fourth Energy Transition Monitoring Report. BMWi (German Federal Ministry for Economic Affairs and Energy), Technical Report.

Calvin, K., J. Edmonds, B. Bond-Lamberty, L. Clarke, S.H. Kim, P. Kyle, S.J. Smith, A. Thomson, and M. Wise (2009). "Limiting climate change to 450 ppm CO_2 equivalent in the 21st century." *Energy Economics* 31(Supplement 2): S107-S120. https://doi.org/10.1016/j.eneco.2009.06.006.

CGDD (2016). Les énergies renouvelables en France en 2015. CGDD (Commissariat Général au Développement Durable), French Ministry of Environment and Energy, Technical Report.

Clarke, L., J. Edmonds, V. Krey, R. Richels, S. Rose, and M. Tavoni (2009). "International climate policy architectures: overview of the EMF 22 International scenarios." *Energy Economics* 31(Supplement 2): S64-S81. https://doi.org/10.1016/j.eneco.2009.10.003.

Delarue, E.D., A.D. Ellerman, and W.D. D'haeseleer (2010). "Short-term CO_2 abatement in the European power sector: 2005–2006." *Climate Change Economics* 1(2): 113–133. https://doi.org/10.1142/S2010007810000108.

De Perthuis, C. and B. Solier (2018). La transition énergétique face au tempo de l'horloge climatique. CEC, Information & Débats n°56.

Entsoe (2016). Yearly statistics and adequacy Retrospect 2015.

Eurelectric (2011). Power Statistics and Trends 2011.

Hansson, J., G. Berndes, F. Johnsson, and J. Kjärstad (2009). "Co-firing biomass with coal for electricity generation – An assessment of the potential in EU27." *Energy Policy* 37(4): 1444–1455. https://doi.org/10.1016/j.enpol.2008.12.007.

IEA (2012). World Energy Outlook 2012.

Jakob, M., G. Luderer, J. Steckel, M. Tavoni, and S. Monjon (2012). "Time to act now? Assessing the costs of delaying climate measures and benefits of early action." *Climatic Change* 114: 79–99. https://doi.org/10.1007/s10584-011-0128-3.

Kannan, R. and H. Turton (2013). "A Long-Term Electricity Dispatch Model with the TIMES Framework." *Environmental Modeling and Assessment* 28(3): 325–343. https://doi.org/10.1007/s10666-012-9346-y.

Linden, M., M. Maëkelä, and J. Uusivuori (2013). "Fuel Input Substitution under Tradable Carbon Permits System: Evidence from Finnish Energy Plants 2005–2008." *The Energy Journal* 34(2): 145–166. http://dx.doi.org/10.5547/01956574.34.2.5.

Lintunen, J. and H.L. Kangas (2010). "The case of co-firing: The market level effects of subsidizing biomass co-combustion." *Energy Economics* 32(3): 694–701. https://doi.org/10.1016/j.eneco.2009.11.004.

Luderer, G., V. Bosetti, M. Jakob, M. Leimbach, J. Steckel, H. Waisman, and O. Edenhofer (2012). "The economics of decarbonizing the energy system–results and insights from the RECIPE model intercomparison." *Climatic Change* 114: 9–37. https://doi.org/10.1007/s10584-011-0105-x.

Luderer, G., C. Bertram, K. Calvin, E. De Cian, and E. Kriegler (2016). "Implications of weak near-term climate policies on long-term mitigation pathways." *Climatic Change* 136: 127–140. https://doi.org/10.1007/s10584-013-0899-9.

Mei, B. and M. Wetzstein (2017). "Burning wood pellets for US electricity generation? A regime switching analysis." *Energy Economics* 65: 434–441. https://doi.org/10.1016/j.eneco.2017.05.025.

Netherlands Enterprise Agency (2016). SDE+ 2016–Instructions on how to apply for a subsidy for the production of renewable energy.

Nordhaus, W.D. (2017). "Revisiting the social cost of carbon." *Proceedings of the National Academy of Sciences of the United States of America* 114(7): 1518–1523. https://doi.org/10.1073/pnas.1609244114.

Rentizelas, A.A., A.I. Tolis, and I.P. Tatsiopoulos (2012). "Investment planning in electricity production under CO_2 price uncertainty." *International Journal of Production Economics* 140(2): 622–629. https://doi.org/10.1016/j.ijpe.2010.11.002.

RTE (2011). Statistiques Production Consommation Échanges 2011. Réseau de Transport d'Électricité (RTE).

Sands, R.D., K. Schumacher, and H. Förster (2014). "U.S. CO_2 Mitigation in a Global Context: Welfare, Trade and Land Use." *The Energy Journal* 35(SI1): 181–197. http://dx.doi.org/10.5547/01956574.35.SI1.10.

Santisirisomboon, J., B. Limmeechokchai, and S. Chungpaibulpatana (2001). "Impacts of biomass power generation and CO_2 taxation on electricity generation expansion planning and environmental emissions." *Energy Policy* 29(12): 975–985. https://doi.org/10.1016/S0301-4215(01)00028-3.

Solier, B. (2014). "An economic and ex post analysis of the impacts of the carbon price on the European power sector." PhD thesis, Paris-Dauphine University.

Strauss, W. (2017). *Trump Wants to Save the Coal Industry. We Offer a Plan that can Help*. FutureMetrics.

Weigt, H., A.D. Ellerman, and E. Delarue (2013). "CO_2 abatement from renewables in the German electricity sector: Does a CO_2 price help?" *Energy Economics* 40(1): 149–158. https://doi.org/10.1016/j.eneco.2013.09.013.

Xian, H., G. Colson, B. Mei, and M.E. Wetzstein (2015). "Co-firing coal with wood pellets for U.S. electricity generation: a real options analysis." *Energy Policy* 81: 106–116. https://doi.org/10.1016/j.enpol.2015.02.026.

APPENDIX A

Extensive documentation on the model is available in supplementary materials submitted with this paper. This includes the GAMS codes, the data files, appendix on treatments for the data, and the complete mathematical formulation of the model. More documentation is available on request.

APPENDIX B

Table 5: German nuclear phase-out plan, based on World Nuclear Association (www.world-nuclear.org**) and WEPP data.**

City	Unit	Year Shutdown	Year Commissioning	MW
Biblis (68643)	BIBLIS A	2011	1974	1225
Biblis (68643)	BIBLIS B	2011	1976	1300
Brunsbuttel (25541)	BRUNSBUTTEL 1	2011	1977	806
Essenbach (84051)	ISAR 1	2011	1979	912
Geestacht (21502)	KRUMMEL 1	2011	1984	1402
Neckarwestheim (74382)	NECKAR 1	2011	1976	840
Philippsburg (76661)	PHILIPPSBURG 1	2011	1980	926
Stadland (26935)	UNTERWESER 1	2011	1978	1410
Grafenrheinfeld (97506)	GRAFENRHEINFELD 1	2015	1982	1345
Gundremmingen (89355)	GUNDREMMINGEN B	2017	1984	1344
Philippsburg (76661)	PHILIPPSBURG 2	2019	1985	1458
Brokdorf (25576)	BROKDORF 1	2021	1986	1480
Emmerthal (31860)	GROHNDE 1	2021	1985	1430
Gundremmingen (89355)	GUNDREMMINGEN C	2021	1985	1344
Lingen (49811)	EMS (LINGEN) 1	2022	1988	1400
Essenbach (84051)	ISAR 2	2022	1988	1488
Neckarwestheim (74382)	NECKAR 2	2022	1989	1400

Table 6: Decommissioning of German nuclear units based on the nuclear phase-out plan (Table 5).

Year	Per year decommissioning	Cumulated decommissioning
2011	8821	8821
2012	0	8821
2013	0	8821
2014	0	8821
2015	1345	10166
2016	0	10166
2017	1344	11510
2018	0	11510
2019	1458	12968
2020	0	12968
2021	4254	17222
2022	4288	21510

APPENDIX C

Table 7: Main results for coal-based electricity with the 2020 and 2030 RES targets.

	2015		2020		2030	
Germany						
	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES
Yearly Power Generation (TWh_{elec} per year)	316	267.1	350.1	237.6	385	175.3
Total Installed Capacities (GW)	64.2	51.2	65.1	51.2	65.1	51.2
Cumulated New Capacities (GW)	13	—	13.9	—	13.9	—
France—Nuclear Reduction						
	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES
Yearly Power Generation (TWh_{elec} per year)	83.6	39	99.8	22.1	193.4	58.3
Total Installed Capacities (GW)	24.5	12.8	25.7	12.8	25.7	12.8
Cumulated New Capacities (GW)	17	5.3	18.2	5.3	18.2	5.3
France—Nuclear Prolongation						
	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES	Co-firing in RES	Co-firing out RES
Yearly Power Generation (TWh_{elec} per year)	55.8	18.5	65.3	14.6	78.5	10.5
Total Installed Capacities (GW)	15.5	7.5	15.5	7.5	15.5	7.5
Cumulated New Capacities (GW)	8	—	8	—	8	—

APPENDIX D

Figure 10: Comparative evolution of French and German decommissioning for main conventional technologies.

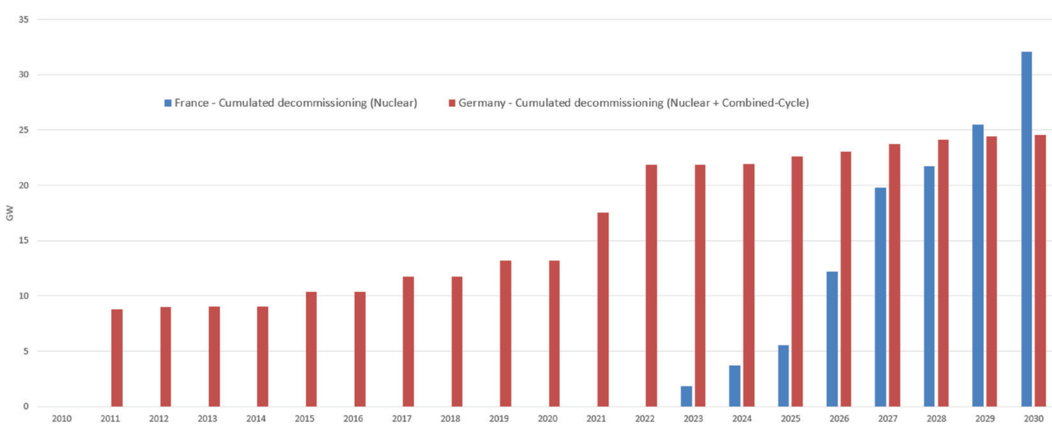


Figure 11: Levelized lifetime cost of electricity (LLCOE) computed for different RES technologies (Biogas-ST = Biogas Steam Turbine ; Biogas-CC = Biogas Combined Cycle ; Biomass-ST = Dedicated biomass Steam Turbine). For each technology, the value in bracket reflects the availability factor. In the case of biomass, AR stands for Agricultural Residues and WP for Wood Pellets.