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CO-FIRING COAL WITH BIOMASS UNDER MANDATORY OBLIGATION FOR RENEWABLE ELECTRICITY:

IMPLICATION FOR THE ELECTRICITY MIX

Vincent BERTRAND[1, 2,3]

This paper analyses the effect of recognizing co firing coal with biomass as a renewable energy sources (RES) so as to meet the mandatory obligations in electricity. We provide simulations for the French and German electricity mix, with investigations about consequences for cost savings in the power sector and CO_2 emissions. Results indicate that, if co-firing is recognized as a RES, coal would crowd-out traditional RES, not only with increased generation from existing coal plants, but also with additional investments in coal that would be substituted for traditional RES. Investments in coal may be more significant in France than in Germany, which may correspond to adding up to 243% of coal capacity in French electricity by 2030, whereas the same progression is 27% in Germany. Regarding CO_2 emissions, we find sharp increases when co-firing is recognized as a RES. The rise is more significant in Germany due to more coal capacities. In the case of France, the magnitude of increased emissions highly depends on the share of nuclear electricity, with fewer increase when old nuclear stations are prolonged. Finally, we find that including co-firing in the set of RES reduces the overall costs associated with managing the power system. We also balanced the cost saving for the power sector with the increased social cost from higher CO_2 emissions. Results show that the cost saving is dominated by the increased carbon cost for the society if the carbon valuation is around 100 Euros per tCO_2, except in France when old nuclear stations are prolonged.

1. CRESE EA3190, Univ. Bourgogne Franche-Comté, F 25000 Besançon, France
2. Climate Economics Chair, Univ. Paris Dauphine, Paris, France
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Chaire Economie du Climat Palais Brongniart, 4ième étage 28 Place de la bourse 75002 PARIS

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 renewable electricity. Co-firing provides short-term opportunities for increasing the share of renewable energy sources (RES) 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. These include countries with high coal electricity such as Poland or the UK, which raised concerns about the consequences for coal's contribution 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 (notably due to European limits on SO_X and NO_X emissions) 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.

The aim of this paper is to analyze the consequences for the electricity mix when co-firing is recognized as renewable electricity. To do this, we use the Green Electricity Simulate (GES), 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). We run simulations with and without co-firing in the set of RES technologies that are accounted for to meet the RES targets. We focus on France and Germany rather than considering countries that have already included provisions to support co-firing as another RES. France and Germany offer good cases of study for our analysis because of their large coal capacities (French capacity is not negligible in volume, although far less significant than German capacity, see Table 3) and because no support scheme for co-firing has been implemented in these countries so far.

Results confirm that recognizing co-firing as a RES would jeopardize investments in traditional RES, 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, which limits the ability to use 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 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 RES may more radically change the French capacity mix, in which coal may change status and become an important source of French electricity.

Regarding CO_2 emissions, results indicate that recognizing co-firing as a RES generates sharp increases because of reduced traditional RES (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 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 RES 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 in most cases. When balancing this cost saving against the increased social cost from higher CO_2 emissions, results show 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 old 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 a brief presentation of the methodology and data. Section 4 presents 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).[1]

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 a 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.

Table 1: Treatment of 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.

[1] 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 only burns biomass, and, in the UK, it is entitled to receive a more generous subsidy treatment compared with co-firing (Table 2).

[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 MWh_{elec} (the applied rate of certificates depends on the percentage of biomass in the coal plant).

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).

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.

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 RES. 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 (which are based on fossil fuel sources) and the electricity cost from RES.[2] 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

[2] 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).

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 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.[3]

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.

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

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

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

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)

3. Simulation methodology

3.1. 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

[3] www.argusmedia.com

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).

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.[4] 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.

[4] 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 (Bertrand and Le Cadre, 2015). In the case of coal plants, this calculation can be implemented taking into account the ability to co-fire coal with biomass or not.

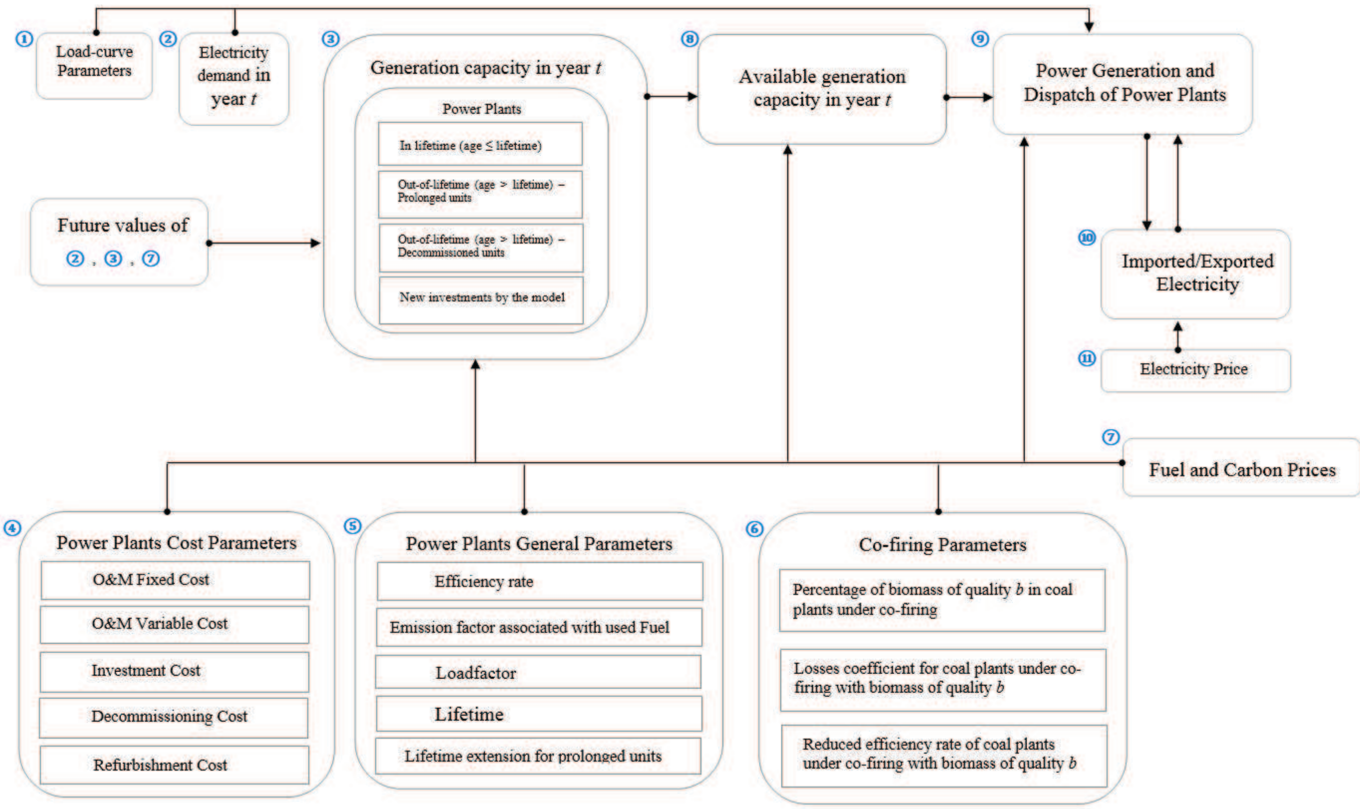

Figure 1: Overview of the GES optimization problem.

3.2. 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.[5]

In order to derive realistic projections, the model has been calibrated to actual market data. 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. This is a necessary second-best approach 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

[5] All the data and references are available in online appendices from Bertrand and Le Cadre (2015).

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 the International Energy Agency (IEA) 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).[6]

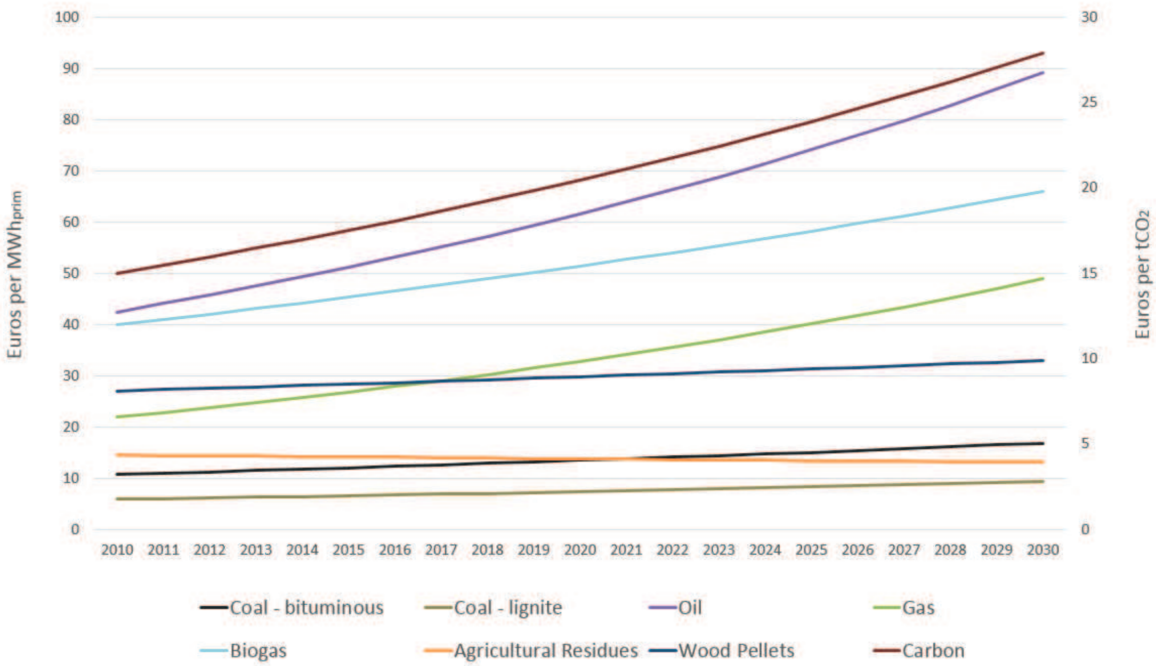

Figure 2: Main fuel and carbon prices.

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.[7] The 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).

[6] All the price data is available in Bertrand and Le Cadre (2005) with detailed calculations in online appendices.
[7] See Power Statistics on www.entsoe.eu.

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 A). 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 (similar to the German phasing-out and in line with the French nuclear strategy enacted by France's energy transition law of July 2015), we have included an additional constraint in the model that proscribes prolongation of out-of-lifetime nuclear power stations (that would otherwise be prolonged by the model). This is equivalent to exogenous decommissioning of old nuclear power plants.[8]

3.3. 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 a 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 a 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 RES:

$$\sum_{u \in URES} P_{t,u}^{i} \geq \tau_{2020}^{i} \times \left(\sum_{u \in U} P_{t,u}^{i}\right), \tag{1a}$$

$$\sum_{u \in URES} P_{t,u}^{i} + \sum_{u \in UC} \sum_{b \in FSB} \left(\eta_{u,b}^{cf} F_{t,u,b}^{i}\right) \geq \tau_{2020}^{i} \times \left(\sum_{u \in U} P_{t,u}^{i}\right), \tag{2a}$$

where $P_{t,u}^{i}$ stands for power generation from unit u in country $i \in [France, Germany]$ during year t, $\forall t \in [2020, \dots, 2030]$. τ_{2020}^{i} is the 2020 RES target of country i (percentage of RES 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

[8] In general, results from GES indicate that it is always cheaper to extend the life of old nuclear power plants, rather that decommissioning them to consider new investments. This heavily relies on the IEA calculation assumptions used, in which prolongation does not entail additional costs for future decommissioning because expenses associated with decommissioning have already been provisioned during the theoretical lifetime (*i.e.* periods in which the age is lower than the theoretical lifetime), whereas new investments need additional provisions for future decommissioning.

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.[9]

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

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

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

$$\sum_{u \in URES} P^i_{2030,u} \geq \tau^i_{2030} \times \left(\sum_{u \in U} P^i_{2030,u}\right), \quad \textbf{(1b)}$$

$$\sum_{u \in URES} P^i_{2030,u} + \sum_{u \in UC} \sum_{b \in FSB} \left(\eta^{cf}_{u,b} F^i_{2030,u,b}\right) \geq \tau^i_{2030} \times \left(\sum_{u \in U} P^i_{2030,u}\right). \quad \textbf{(2b)}$$

4. Results and discussions

4.1. Implications for the electricity mix

Results confirm that recognizing co-firing as a RES may greatly modify the electricity mix, whatever the country.[10] We observe an increased contribution from coal when co-firing is counted as a 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

[9] 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, $\eta^{cf}_{u,AR} < \eta^{cf}_{u,WC} < \eta^{cf}_{u,WP} < \eta^{cf}_{u,TOP}$ (Bertrand and Le Cadre, 2015).

[10] 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.

capacity remains constant so investments in traditional RES disappear compared with the situation in which co-firing is considered a non-renewable option.

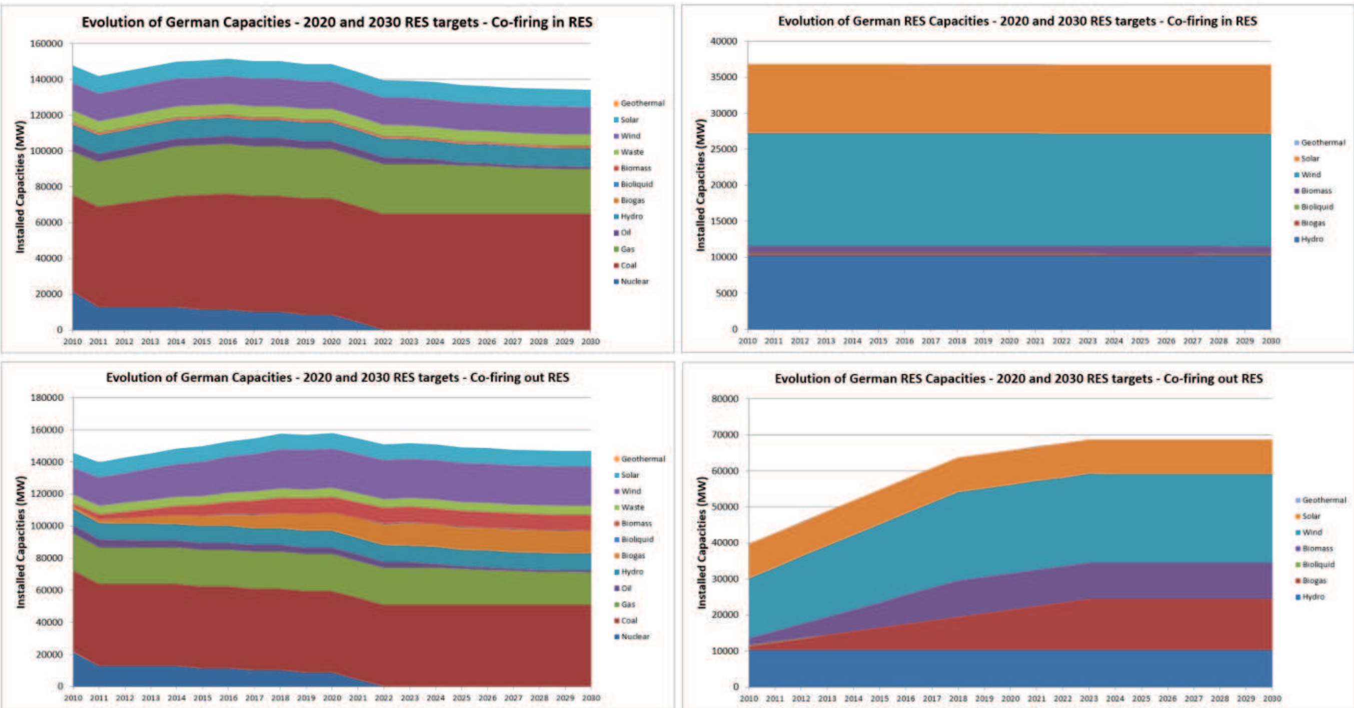

Figure 3: Evolution of the German capacity mix (all technologies, left panel; RES technologies, right panel), depending on whether or not co-firing is included in the set of RES technologies that are accounted for to meet the RES targets.

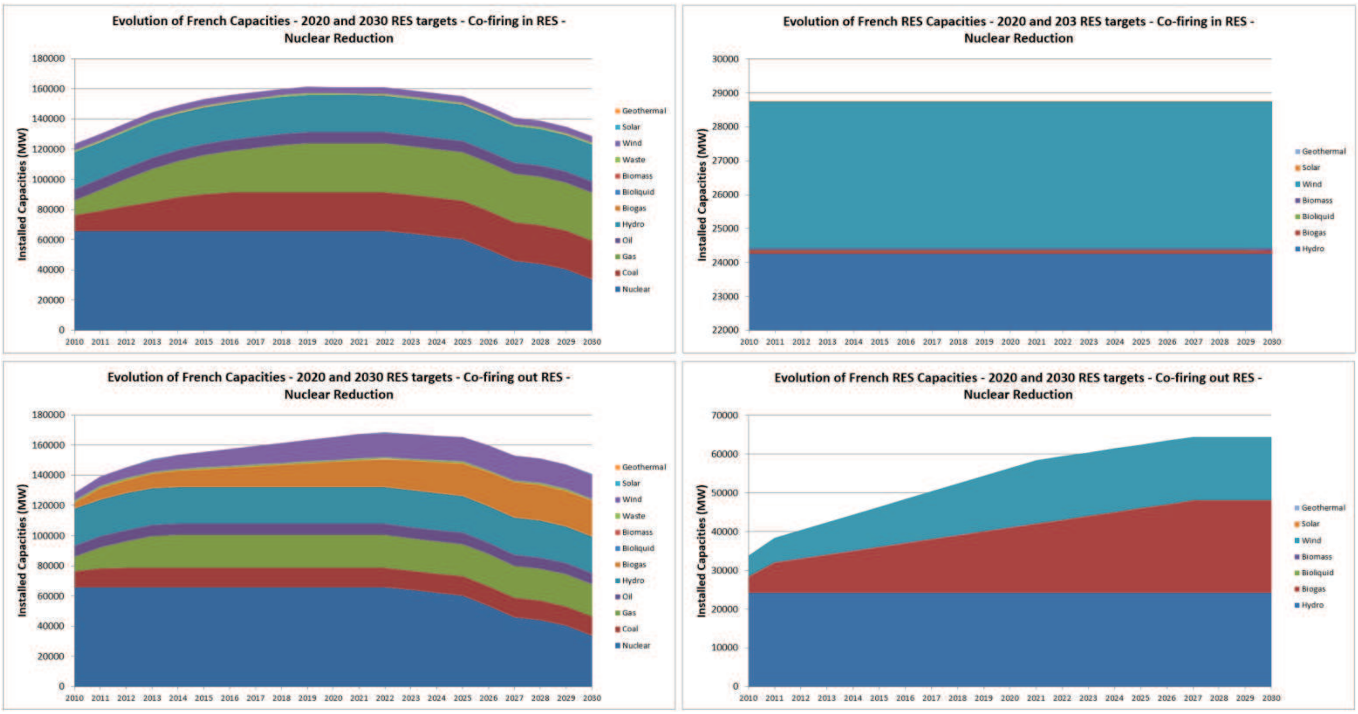

Figure 4: Evolution of the French capacity mix (all technologies, left panel; RES technologies, right panel) with exogenous decommissioning of out-of-lifetime nuclear units depending on whether or not co-firing is included in the set of RES technologies that are accounted for to meet the RES targets.

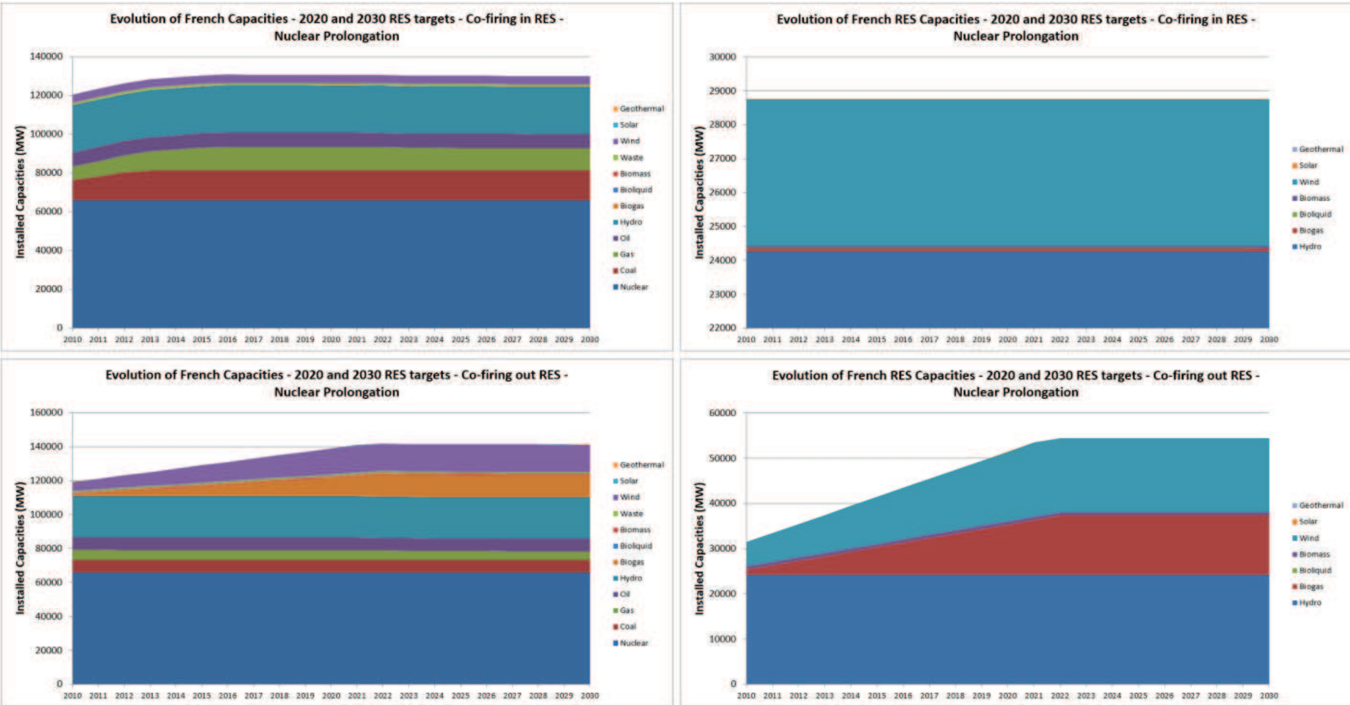

Figure 5: Evolution of the French capacity mix (all technologies, left panel; RES technologies, right panel) with endogenous prolongation of out-of-lifetime nuclear units depending on whether or not co-firing is included in the set of RES technologies that are accounted for to meet the RES targets.

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 RES (Appendix B). 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 RES to meet the RES targets through co-firing. The new coal investments vanish when co-firing is excluded from the set of RES. 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 RES, the increased coal contribution is maximal (Figures 6), which translates into more investments in new coal stations (Appendix B). In this case, the additional French coal capacities may attain 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 RES. Comparatively, the maximal additional coal capacity in Germany is close to 14 GW when co-firing is included in the set of RES. In this case, the 2030 German capacity mix exhibits a progression 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 form RES).[11] That is, although including co-firing in RES 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.

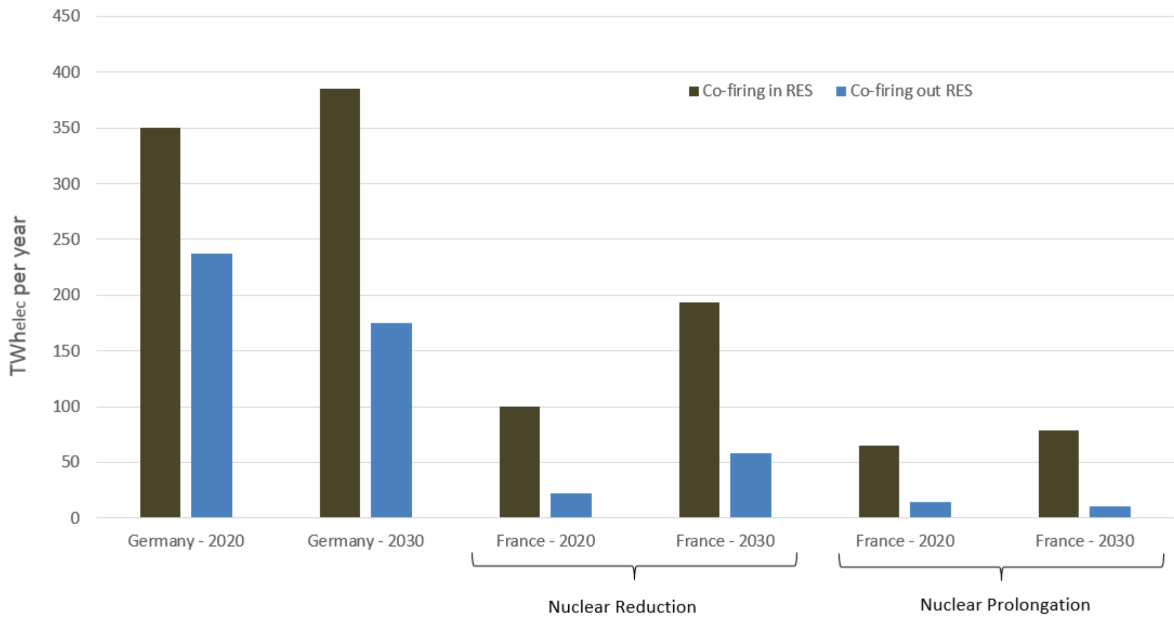

Figure 6: Coal-based power generation (hard-coal and lignite) in France and Germany depending on the treatment of co-firing regarding the RES targets.

Figures 3, 4, and 5 show that when co-firing is omitted from the set of RES, investments in traditional RES (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 RES with problems of intermittency and resulting low availability. In the case of wind, the drawback of low availability is outweighed by a low investment cost

[11] 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.

with zero marginal cost, so that it remains a competitive option.[12] Second, investing in biogas and dedicated biomass meets the need for new conventional generation capacities with German nuclear phasing-out, exogenous decommissioning of French old nuclear power stations, and substantial endogenous decommissioning of out-of-lifetime German combined-cycle units (Figure 10 in Appendix C).[13] Biogas and dedicated biomass offer interesting characteristics in this context, because they are RES technologies with high availability as conventional units.

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 (dedicated biomass is the second best dispatchable RES after biogas at the beginning of the time horizon, see Figure 11 in Appendix C), once the investment potential for biogas has been exhausted.[14]

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 RES, 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 RES. 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.

[12] The competitiveness of biogas, wind, and dedicated biomass is illustrated by the levelized lifetime cost of electricity (LLCOE) in Appendix C.

[13] 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.

[14] Setting such per technology maximal amounts for yearly investments is a common assumption in simulation models for electricity (*e.g.* Rentizelas *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.

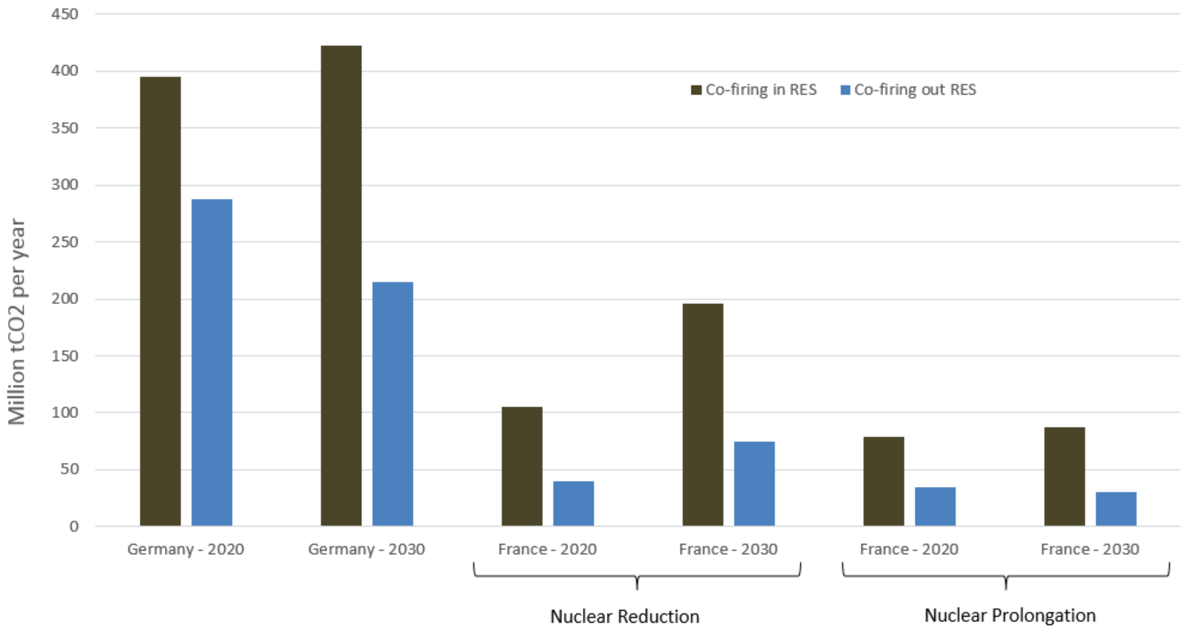

Figure 7: CO_2 emissions from power generation in France and Germany depending on the treatment of co-firing regarding the RES targets.

Figure 7 shows that recognizing co-firing as a RES generates sharp increases of CO_2 emissions due to reduced traditional RES (carbon-free) and more coal in the electricity mix. As illustrated in Figure 6, including co-firing in the set of RES produces a much larger increase in coal-based generation in the case of Germany due to its much greater coal capacities. This translates into 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 (if implemented with high quality biomass, co-firing can cut CO_2 emissions from existing coal plants by up to 50 percent without additional investment) for carbon-free RES inevitably increases CO_2 emissions. In France, the effect on CO_2 emissions depends largely on the share of nuclear 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 RES, the large increased contribution from coal (Figures 6), which is substituted for carbon-free RES 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 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 RES 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 a 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 to complying with the RES constraint without increasing the cost in base-load because nuclear power is still predominant in this generation segment.[15] By contrast, when prolongation of nuclear power is not allowed, increased 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.

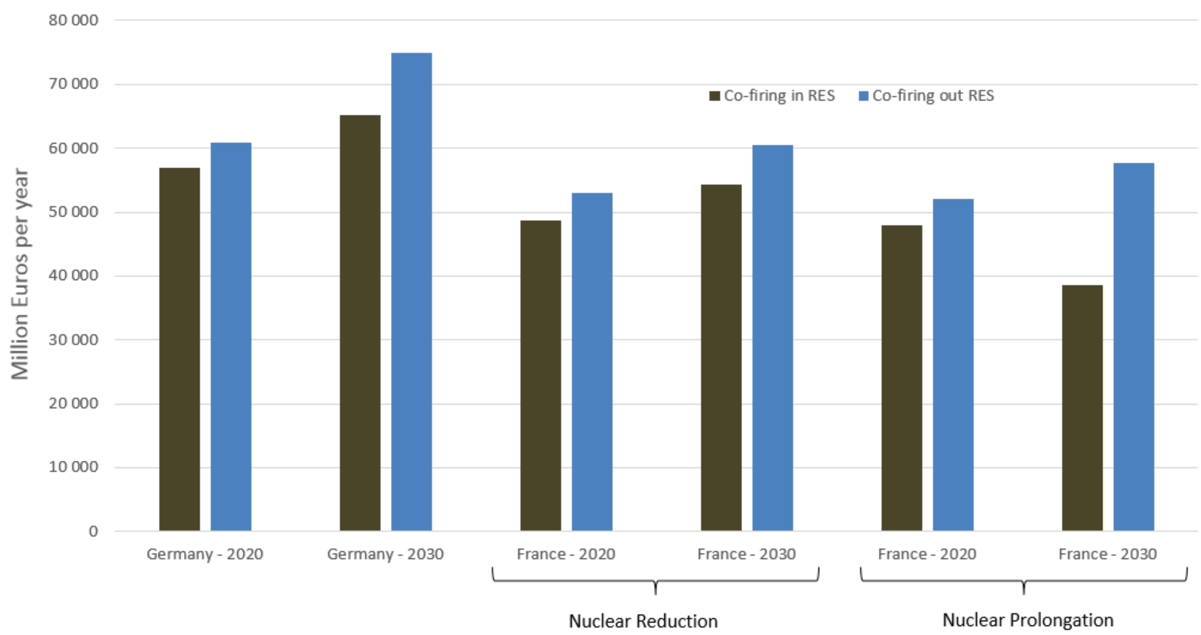

Figure 8: Overall electricity cost to meet annual power demand in France and Germany depending on the treatment of co-firing regarding the RES targets.

[15] For the same reasons, recognizing co-firing as a 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).

A more comprehensive comparison should consider the increased carbon cost for society when recognizing co-firing as a RES. On the one hand, any cost saving due to including co-firing in the set of RES may reduce the cost of policies to attain objectives about 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.[16] 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.

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

As illustrated in Figure 9, the cost saving from including co-firing in RES 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.

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.

Results indicate that, if co-firing is recognized as a RES, coal would crowd-out traditional RES 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 RES. 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 a RES. Indeed, substituting coal for carbon-free RES 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 increase when old nuclear power stations are kept in service. Finally, we find that including co-firing in the set of RES 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 in most cases requires no 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 the 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 RES if co-firing is recognized as a RES. 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. Moreover, this may be a concern for social acceptability among populations that should be increasingly concerned by tackling climate change effects and reducing the share of polluting fossil fuels in the energy mix. The cost arising from adapting electricity generation to climate policy is an important issue in this context. As illustrated in the recent US presidential campaign, policy makers can also face complicated trade-offs between climate concerns and employment from the coal industry. In all of this, co-firing can be a useful option. However, although it can provide efficient means of reducing CO_2 emissions in the short-run, it cannot be seen as a viable long-term strategy because it would jeopardize the necessary transition towards more renewables and less carbon in energy. This is something policy makers should remember when considering whether it is opportune to include provisions for co-firing in the support schemes for renewable electricity.

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Appendix A

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 B

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

Germany

	2015		2020		2030	
	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

	2015		2020		2030	
	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

	2015		2020		2030	
	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 C

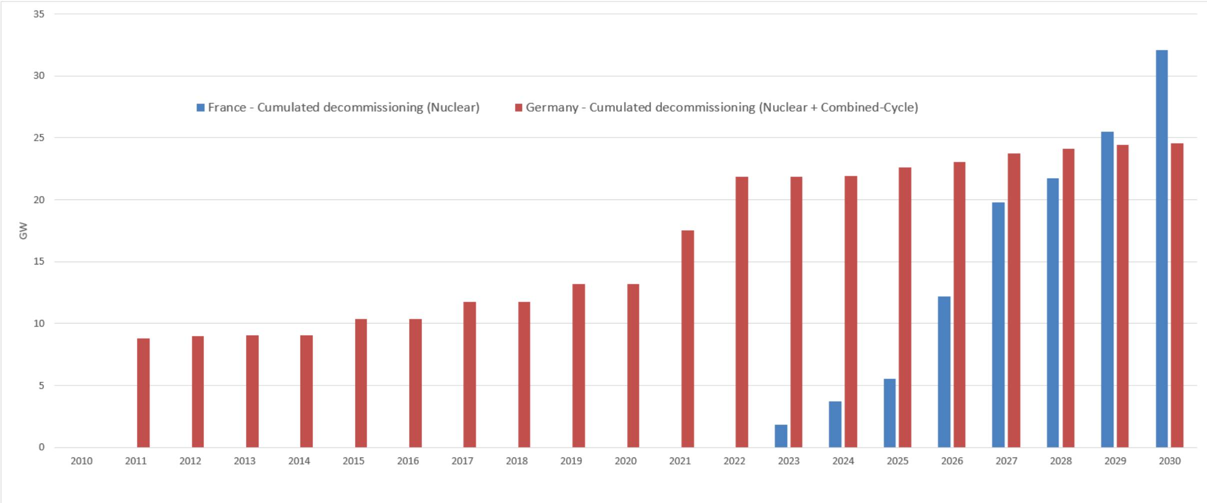

Figure 10: Comparative evolution of French and German decommissioning for main conventional technologies.

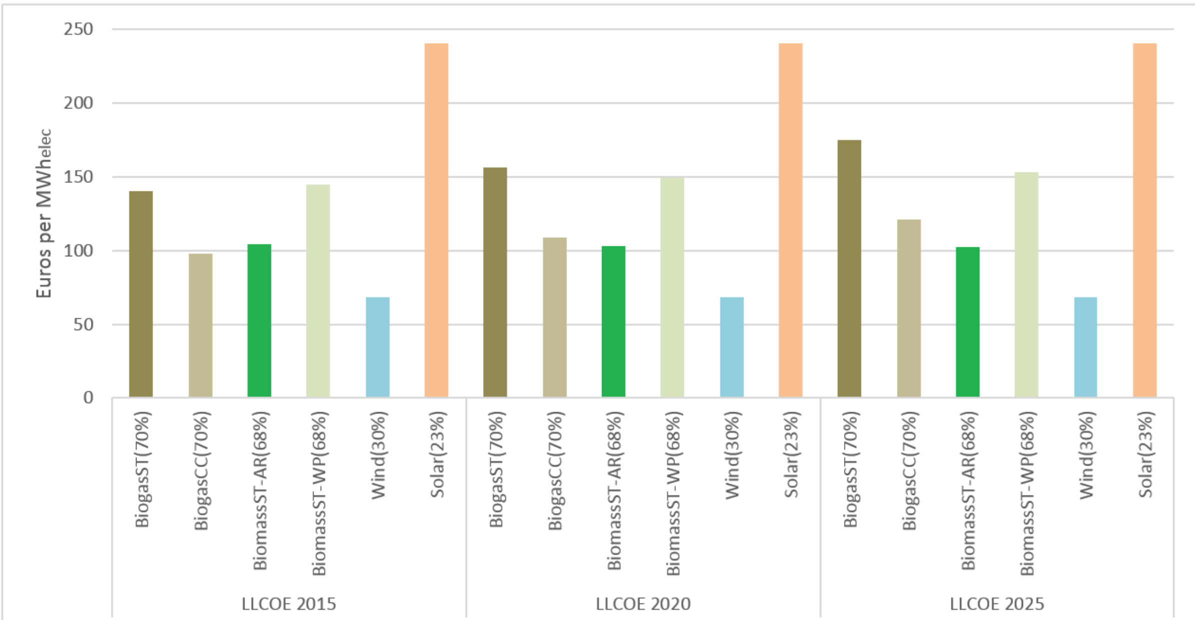

Figure 11: Levelized lifetime cost of electricity (LLCOE) computed for different RES technologies (Biogas-ST = Biogas Steam Turbine ; Biogas-CC = Biogas Combined Cycle ; Biomass-ST = Dedicated biomass Steam Turbine). For each technology, the value in bracket reflects the availability factor. In the case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