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SIMULATING THE USE OF BIOMASS IN ELECTRICITY WITH THE GREEN ELECTRICITY SIMULATE MODEL:

AN APPLICATION TO THE FRENCH POWER GENERATION

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This paper presents the version 1.0 of the Green Electricity Simulate (GES), which is a simulation model that has been designed to investigate questions related to biomass-based electricity in the European countries with a special focus on the biomass co-firing in coal plants. We extend previous works in essentially three directions. We provide the first simulation model for electricity taking into account co-firing with a wide range of induced effects. Second, we analyze the impact of co-firing on decisions about prolongation or decommissioning of out-of-lifetime coal plants. Finally, we investigate the consequences of recognizing co-firing as a contribution to achieve the Renewable Energy Source (RES) objectives in power generation. As an illustration, we apply the model to the French power sector. Overall, the results indicate that the biomass demand from co-firing is much greater than that from dedicated biomass units, and that co-firing can heavily influence the composition of the fleet under certain circumstances and policy arrangements. In addition, we show that increasing the carbon price generates a move towards quality that induces consuming more high-quality biomass (e.g. wood pellets or torrefied pellets). We also identify that co-firing may encourage to prolonging coal plants that would be decommissioned otherwise. Finally, we find that recognizing the biomass part of co-firing as a renewable may lead to maintaining a high share of coal in the power mix, which may be a concern for social acceptability in the long run.

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1. Introduction

During the last decade, the European Union (EU) has adopted new energy and environmental policies to reduce CO_2 emissions and promote renewable electricity. In that context, biomass has been increasingly acknowledged as a key energy source to achieve the EU targets. Notably, the ability of power producers to increase the renewable energy sources (RES) in power generation with no investments, through the co-firing of biomass in coal plants, gives to biomass a strong interest. Given the high percentage of coal in European electricity, co-firing provides great opportunities for increasing the share of renewable electricity and reducing CO_2 emissions in the near-term, through reliable technologies that are not subject to problems of intermittency.[1]

To date there is a range of electricity models that have been developed to simulate the impact of energy and environmental policies.[2] However, very few have investigated the question of the cost competitiveness of biomass for electricity production.[3] Among the scarce contributions, Santisirisomboon *et al.* (2001) simulate the power generation expansion planning in Thailand, over the period 1999-2015. The authors focus on the cost competitiveness of dedicated biomass power plants with respect to fossil-based power plants, when introducing a carbon price. They identify that the introduction of a carbon tax modifies the capacity mix from coal-based to biomass-based power plants, and increases the number of combined cycle gas plants. More recently, Rentizelas *et al.* (2012) have provided a long-term simulation model, which investigates the effect of various carbon price scenarios on investment decisions regarding the future electricity generation mix of Greece up to 2050. Several RES technologies are considered in the model, including dedicated biomass power plants. One of the main results indicates that medium or high carbon prices may render some of the RES (including biomass units) more cost-effective than conventional technologies, whereas low carbon prices do not favor an increased use of RES.

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[1] According with the Directive 2003/87/EC (establishing the EU ETS – European Union Emission trading Scheme – and the related rules) and the Decision 2007/589/EC (establishing guidelines for the monitoring and reporting of greenhouse gas emissions), emissions from burning biomass are exempted from surrendering corresponding allowances. This is equivalent to a zero emission factor applied to biomass. See DECC-SAP (2011) and Bertrand *et al.* (2013) for an overviews about actual CO_2 emissions from burning biomass.

[2] Electricity models or electricity simulation models refer to models that simulate power generation and/or investment decisions in the power sector. See Kannan and Turton (2013) and Rentizelas *et al.* (2012) for a review of this literature.

[3] One may also mention here the contributions of Gan and Smith (2006) and Skytte *et al.* (2006). However, even though these papers also analyze questions related to biomass-based electricity, they do not provide simulations of power generation or investment decisions in the power sector, as the electricity simulation models reviewed in this paper. Moreover, neither of these works considers the co-firing of biomass in coal plants.

While both Santisirisomboon *et al.* (2001) and Rentizelas *et al.* (2012) have integrated biomass-based electricity in their simulations, neither of these works has considered co-firing. Actually, very few papers analyze the economics related to co-firing. Among them, Berggren *et al.* (2008) estimate the technical potential for co-firing in Poland for 2010, minimizing the cost to implement co-firing. This paper uses a static framework, in which a model simulates the optimal allocation of different types of biomass from the Polish resources, toward different types of coal plants from the existing coal-based capacities in Poland. Moreover, the authors derive the CO_2 abatements from co-firing. Another contribution on this topic comes from Bertrand (2013), which provides a theoretical framework that enables computing biomass and CO_2 breakeven points for co-firing, based on expressions of the marginal cost of coal-based electricity with and without co-firing.

The aim of this paper is to present the version 1.0 of the Green Electricity Simulate (GES) model, which extends the mentioned literature on electricity simulation models by taking into account the biomass co-firing in coal plants with a wide range of effects that may be induced by co-firing. In particular, it allows analyzing the competition between different types of biomass with different qualities (and thus different impacts on the conversion efficiency of coal plants under co-firing) to feed the electricity sector. It also provides a framework to investigate the impact of co-firing on decisions about decommissioning or prolongation of out-of-lifetime coal plants. To the best of our knowledge no previous model has provided a so comprehensive analysis of biomass-based electricity and co-firing.

GES is a cost-minimization model for production and investment decisions in the power sector, which has been designed to analyze the effect of co-firing, with various economic variables, on the development of biomass-based electricity in the electricity mix of European countries. It is a dynamic partial equilibrium model, which uses a bottom-up linear programming approach, to optimize the dispatch of generation capacities and investment in new power plants. The model is implemented under the General Algebraic Modeling System (GAMS), and it considers yearly time periods between 2010 and 2030. For each year in the considered time interval, GES determines the power generation mix and investment decisions, so as to meet electricity demand at the least cost. Furthermore, the model identifies which are the out-of-lifetime power plants at the beginning of each year, which ones are decommissioned, and which one are refurbished and prolonged. Hence, the GES model provides an original and flexible tool to investigate questions such as: What would be the biomass demand from the power sector under different price and policy contexts? How significant may be the biomass demand from co-firing compared with that from dedicated biomass power plants? What is the influence of the carbon price? How decisions about prolongation/decommissioning of out-of-lifetime coal plants may be impacted by co-firing? Will co-firing lead to prolong coal plants that would be decommissioned otherwise? What would be the consequences for the electricity mix if co-firing is recognized as a contribution to achieve the RES objectives in power generation? Etc. We propose in this paper an application to the French power sector.

The remainder of the paper is organized as follows. In section 2, we give a brief overview of questions related to biomass-based electricity. Section 3 introduces the GES modeling and methodology. Section 4 is devoted to description of the main data and parameters for this application to the French power sector. In section 5, we present some results and discussions. Section 6 concludes.

2. Technical options for biomass-based electricity

2.1 Combustion in dedicated biomass power plants

Dedicated biomass power plants (*i.e.* power plants that are especially designed for biomass) have to be adapted to supply limitations. Accordingly, their typical size is smaller than that of coal plants (1-100 MW, which is about ten times smaller than coal plants), because local feedstock are limited and transportation costs are high. The small size strongly increases investment costs and lowers conversion efficiency compared with co-firing in coal plants (IEA, 2007b).

2.2 Biomass co-firing in coal-power stations

Co-firing is the simultaneous combustion of biomass and coal in a coal plant. It is the cheapest option for using biomass in electricity. A wide variety of biomass can be used, including herbaceous and woody materials, wet and dry agricultural residues and energy crops. Currently, the typical conversion efficiency for a dedicated biomass power plant is 25-30% (Ecofys, 2010), while the average efficiency for coal plants is around 36% with new state-of-the-art units reaching 45% (Wicks and Keay, 2005). Co-firing is expected to decrease the efficiency of coal plants, due to potential sources of losses associated with biomass (*e.g.* presence of non-preheated air in biomass, increased moisture content, etc). However, the impact is modest for low percentages of biomass (IEA-IRENA, 2013) and conversion efficiency remains higher compared with dedicated biomass plants. Furthermore, much of these difficulties can be overcome through different pre-treatments to improve biomass quality, and increase the quantity of biomass that can be included in coal plants under co-firing.

2.3 Pre-treatment of raw biomass

Most of the co-firing constraints originate from fuel properties. Raw biomass usually has high moisture content that reduces efficiency of coal plants. Various pre-treatments can be applied to raw biomass to avoid these problems (Maciejewska *et al.*, 2006). Basic pre-treatments include drying, chipping and grinding. More advanced pre-treatments are pelletisation and torrefaction. Pelletisation is a process that densifies fine biomass particles into compact and low-moisture capsules by applying pressure and heat. Torrefaction is thermo-chemical pre-treatment that consists of biomass heating in absence of oxygen. Temperatures between 200 and 300°C are needed, which produces a solid uniform product (torrefied biomass) with very low moisture content and high energy density.

The cost of pre-treatment can significantly vary from one option to another, but it is usually high.[4] However, it can be compensated by better operability of fuel (*e.g.* handling, storage and transportation), reduced co-firing constraints and higher efficiency of coal plants. Recent studies point out that the cost of pre-treatment can reach more than 50% for torrefied wood pellets (KEMA, 2012; IEA-Bioenergy, 2012). However, when taking into account benefits of pre-treatment on the whole supply chain, up to the point of combustion, torrefied wood pellets may be more profitable than simple wood pellets (IEA-Bioenergy, 2012).[5]

3. The GES Modeling and Methodology

3.1 Intra-annual time slice, load curve, and hourly power demand

In order to represent the electricity dispatch on intra-annual hourly time slices with unequal power demand, the model associates different pairings between seasons and load curve segments (*e.g.* base or peak load) with different fractions of the annual electricity demand. In addition, each association between a season and a load curve segment represents a *horo-*

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[4] See Maciejewska *et al.* (2006) for cost estimations of different pre-treatment options.

[5] Uslu *et al.* (2008) evaluate torrefaction, pyrolysis and pelletisation in terms of their energy and economic performances on the whole biomass-to-energy supply chain for power generation and biofuel production. Results indicate that torrefaction is more advantageous than pelletisation, while pyrolysis has drawbacks in terms of energy and economic efficiency when compared to other pre-treatments. When torrefaction is combined with pelletisation, this results in the optimal supply chain from an energy and economic perspective.

seasonal time slice, which is associated with a fixed number of hours and then a fraction of the year. For example, the number of hours associated with the summer off-peak load-levels is larger than that of the winter peaks, whereas the winter peaks account for a more significant fraction of the annual electricity demand.

We consider four load levels (*base*, *intermediate*, *mid-* and *extreme-peak*) and four seasons (*winter*, *summer*, *spring-fall*, and *mid-season*), which can be combined to generate nine different horo-seasonal time slices, each one being associated with a fraction of the year and a fraction the annual electricity demand. For this application to the French power sector, we use the values provided in Table 1.

Table 1: Intra-annual (horo-seasonal) time slices with associated numbers of hours and percentages of annual electricity demand.

Definition of seasons and load levels

Season	Associated Months	Notation	Load level	Notation
Winter	December, January, February	S_1	Extreme-Peak	l_0
Mid-season	March, November	S_2	Mid-Peak	l_1
Spring-Fall	April, May, June, September, October	S_3	Intermediate	l_2
Summer	July, August	S_4	Base	l_3

Horo-seasonal time slices, Annual fractions and Percentages of annual power demand

Horo-seasonal time slice	Number of hours	Annual fraction (%)	Percentage of annual demand (low demand event)	Percentage of annual demand (medium demand event)	Percentage of annual demand (high demand event)
l_0S_1	62	0.71	1.09	1.05	1.13
l_1S_1	187	2.13	3.06	3.05	3.20
l_2S_1	872	9.95	13.06	13.24	13.47
l_3S_1	1039	11.86	10.22	10.28	10.25
l_2S_2	745	8.50	20.93	20.84	20.69
l_3S_2	719	8.21	13.16	13.30	13.16
l_2S_3	1870	21.35	8.61	8.65	8.57
l_3S_3	1778	20.30	17.49	17.31	17.30
l_3S_4	1448	16.53	12.39	12.28	12.22

As indicated in Table 1, we consider different repartition of the annual power demand on the horo-seasonal time slices. This allows representing different load curve and power demand conditions. Then a probability is affected to each event, and the model computes expected cost to meet demand that is (randomly) associated with each one of the events (Table 1).[6]

3.2 Electricity generation technologies

GES considers different types of power technologies, defined on the basis of the conversion technology (*e.g.* steam turbine, combustion turbine, combined cycle, etc) and fuel type (*e.g.* bituminous coal, oil, solid biomass, etc). The model uses data for installed capacities of the different technologies in the EU countries from the World Electric Power Plants (WEPP) data base by Platts (2009), which provides an inventory of electric power plants in the world with information such as location, year of commissioning, size, etc.[7]

All existing power technologies in the European electricity system are modeled at an individual level. Moreover, they are grouped into a number of homogenous groups, each one reflecting a bundle of similar technologies (see appendix A2). This allows reducing the amount of data to collect for other cost and technical parameters.[8] In addition to this, we assume a range of fuels. Each fuel can be burn in one or several of the considered technologies (see appendix A2).

Based on the fuel, cost and other technical parameters, we compute the generation costs, for each technology, using the Levelized Lifetime Cost (LLC) methodology (IAEA, 2008; IEA, 2010; Larsson, 2012), which is the usual indicator to evaluate the economic performance of a power system. Moreover, the basic methodology is adapted to estimate the implications of co-firing, and to take the value of heat into account when considering Combined Heat and Power (CHP). The LLC methodology allows converting all streams of costs (investment, operation and maintenance, fuel, etc) into the same unit (Euros/MWh_{elec}), taking into account all the discounted expenses over the whole operating lifetimes. This offers several advantages and flexibilities that enable, for example, determining how different technologies may be more or less competitive depending on their lifetimes. Notably, this

[6] A detailed presentation of the methodology to derive the horo-seasonal time slices and the hourly power demands is available in the online appendix that can be found here: Load Curve and Hourly Power Demand_Appendix_GES1.0.

[7] Slight transformations have been applied to the WEPP data base, in order to create homogenous categories that fit the categories from others references we use in the model. The complete appendix about on how the data base has been processed is available online in the following link: Processing of the WEPP Data Base_Appendix_GES1.0.

[8] The complete appendix about cost and technical data is available online in the following link: Cost and Technical Data_Appendix_GES1.0. As a simplification, we use the same cost parameters and load factors for new and existing power plants. By contrast, we consider higher efficiency rates for new investments compared with existing power plants.

allows fair comparison with other units for power plants that are commissioned in years that are closed to the boundary of the considered time interval.

The model also accounts for the energy storage process from the pumped hydroelectricity. With this formulation, pumped hydroelectricity can be viewed as a flexible (dispatchable) technology that can store and discharge power. This allows the representation of pumped water to store electricity during one time-slice (usually at off-peak hours) and release it in another (usually at peak hours).[9]

Regarding investment decisions, the model considers for each technology an upper limit equal to 1000 MW per year. We follow here the same strategy as Rentizelas *et al.* (2012), because it better reflects real practices and avoids the unnatural cases that would allow using only one power technology in one year thanks to huge investments. Furthermore, as a simplification, we set this upper limit equal to zero for CHP, which is equivalent to disallowing investments in these units. The aim here is to avoid unrealistic massive investments in CHP, neglecting those constraints on availability of heat networks to connect these units. For other reasons, we disallow investment in technologies relying on nuclear, waste, and hydroelectricity. In the case of nuclear, this reflects the political pressure that makes the construction of new reactor unlikely by 2030. Regarding waste, the constraint reflects interactions with incineration legislations that may limit the development of such combustion installations, which rely on fuels that are contaminated with paint, rubbles and chemicals. Finally, we disallow investments in hydroelectricity (conventional and pumped) because almost all the European potential is known to be exhausted.[10]

3.3 Biomass resources and co-firing modeling

3.3.1 Biomass quality and co-firing parameters

[9] This is detailed in the mathematical appendix, which is available online in the following link: GES Mathematical Appendix_Appendix_GES1.0.

[10] Modeling of investment in hydro pumped and storage would necessitate taking into the effect of distance between reservoirs. Moreover, distance between reservoirs may complicate connection to the grid. Accordingly, a more sophisticated modeling approach would be required for investment decisions in this case. In practice, suitable sites (*i.e.* sites with adequate difference in elevation and which are close enough so that reservoirs can be linked by a penstock) are scarce in Europe, and opportunities are highly dependent on the distance between sites. Recent studies show that the EU *theoretical* potential for pumped hydropower energy storage (expressed as the yearly power generation that may arise from new or unconnected reservoirs) is 60 TWh_{elec} for all the EU countries together, when a distance of 20 kilometers between sites is considered (European Commission, 2013). This potential is drastically reduced for lower distances: 7 TWh_{elec} for 5 kilometers, and 0.3 TWh_{elec} for 1 kilometer, mostly in Italy. When environmental and social constraints are considered, the corresponding *realizable* potential in the EU drops to 33 TWh_{elec} (20 kilometers), 4 TWh_{elec} (5 kilometers), and 0.15 TWh_{elec} (1 kilometer).

Including biomass in coal plants may reduce the efficiency rate of stations. The efficiency losses depend on the biomass quality so as (pre-treated) high-quality biomass induces weaker reductions in the efficiency rate. In order to account for this, we use a coefficient measuring losses in the efficiency rate of coal plants under co-firing. Then, the higher the losses coefficient (the lower the biomass quality), the higher the loss in conversion efficiency. This tends to reduce the quantity of biomass to be co-fired, and it increases the cost of co-firing. We also include in our analysis an incorporation rate that corresponds to the percentage of biomass (on energy basis) in the biomass-coal blend for co-firing. The different solid biomass resources we consider are described in Table 2, with the associated losses coefficients and incorporation rates reflecting the quality of each type of biomass (Bertrand, 2013).[11]

Table 2: Solid biomass resources and co-firing parameters.

Solid Biomass Fuel	Quality	Losses coefficient	Incorporation rate (energy basis)
Torrefied Pellets of biomass (TOP)	High quality +	0	50%
Wood Pellets (WP)	High quality -	0.01	20%
Wood Chips (WC)	Low quality +	0.03	10%
Agriculture Residues (AR)	Low quality -	0.05	5%

In Table 2, the value for the incorporation rate (losses coefficient, *respectively*) increases (decreases, *respectively*) when the biomass quality increases. Hence, using biomass with higher quality generates weaker efficiency losses and allows burning greater quantities of biomass in coal plants. This is illustrated in section 3.3.2, which proposes a summary of the co-firing modeling in the GES model.[12]

3.3.2 Marginal cost of coal plants under co-firing configuration

In case of co-firing with biomass b, the efficiency rate of a coal plant c is reduced (which depends on the biomass quality), and we express it using the following equation:

$$\eta_{c,b}^{cf} = \eta_c^{nocf} - \rho_b \, inc_b \, , \qquad \textbf{(1)}$$

where subscript b denotes the type of biomass, and index cf stands for co-firing. ρ_b is the losses coefficient measuring possible decreases in the efficiency rate of coal plants under co-

[11] Co-firing is feasible with incorporation rates between 5 and 50%, depending on the biomass quality (IEA-IRENA, 2013).
[12] The full mathematical exposition of the model is available in the online mathematical appendix.

firing with biomass b, and inc_b represents the incorporation rate associated with biomass b. Finally, η_c^{nocf} is the efficiency rate (MWh_{elec}/MWh_{prim}) of coal plants c without co-firing.

Following Ecofys (2010), we assume a linear relationship between the efficiency losses and the incorporation rate. Hence, we get higher efficiency losses for higher losses coefficients, and, for a given losses coefficient, higher efficiency losses when the incorporation rate increases. As an illustration, let us assume a co-firing situation with the following values: $\eta_c^{nocf} = 0.38$, $\rho_b = 0.05$, and $inc_b = 0.05$ (which corresponds to AR in Table 4). In this case we get $\eta_{c,b}^{cf} = 0.3775$, which corresponds to a loss in conversion efficiency of 0.66%. As a comparison, Baxter (2005) indicates that the efficiency losses associated with co-firing may represent a 0-10% loss in conversion efficiency.

Using equation **(1)** we can express the marginal cost of one MWh of co-fired electricity as follows:

$$MC_c^{cf} = q_{c,c}^{cf}\, C_c + q_{c,b}^{cf}\, B_b + e_c^{cf} CO2, \quad \textbf{(2)}$$

where B_b is the price of biomass b (Euros/MWh_{prim}) and C_c is the price of coal c (Euros/MWh_{prim}). $CO2$ is the carbon price (Euros/tCO_2). $q_{c,b}^{cf}$ ($q_{c,c}^{cf}$, *respectively*) denotes the quantity of biomass b (quantity of coal c, *respectively*) entering in the biomass-coal blend, $h_{c,b}^{cf}$, which allows generating one MWh of co-fired electricity in coal plants of type c with biomass b (*i.e.* $h_{c,b}^{cf} = q_{c,c}^{cf} + q_{c,b}^{cf}$, with $h_{c,b}^{cf} = 1/\eta_{c,b}^{cf}$).

Once $h_{c,b}^{cf}$ and inc_b are known, one can compute the quantities of coal and biomass needed to generate one MWh of co-fired electricity as follows: $q_{c,b}^{cf} = inc_b \times h_{c,b}^{cf}$ and $q_{c,c}^{cf} = (1 - inc_b) \times h_{c,b}^{cf}$. Finally, $e_{c,b}^{cf} = e_c \times q_{c,c}^{cf}$ is the emission factor of coal plants c under co-firing with biomass b (tCO_2/MWh_{elec}). It is computed given e_c, the primary energy emission factor of coal c (tCO_2/MWh_{prim}). Note that in equation of $e_{c,b}^{cf}$, emissions arise from the coal fraction of energy input only. This reflects the zero emission rate applied to biomass in the EU ETS.

3.4 State of the fleet at the beginning of each year

Each generation capacity in the WEPP data base is associated to a vintage, which corresponds to the year of commissioning. Thus, comparing the vintage with the theoretical lifetime, one can deduce if each unit has been prolonged or not. This is important because different treatments in cost calculation must apply to power plants, depending on if they have been prolonged or not. Moreover, comparing the theoretical lifetime of power plants with their age allows determining which are the in- and the out-of-lifetime power plants in each year *t*. On this basis, GES implements a calculation that allows identifying which ones of the out-of-lifetime units must be decommissioned, and which ones must be prolonged.

3.4.1 Identifying the units with prolonged lifetimes

As financial provisions for decommissioning must only apply during the theoretical lifetime, before any refurbishment intervenes (IEA, 2010), no annuity for decommissioning has to be paid when running a unit with a prolonged lifetime. In order to distinguish between the units that have been prolonged or not, we apply some calculations and transformations to the data. This has been done by comparing the age of the units in 2010 (the base year in GES) with the lifetimes of the units that have not been prolonged (*lifetime*) and the ones of the units that have been prolonged (*lifetimeprol*). Table 3 gives an overview of this identification process.

Table 3: Vintages of existing power plants in the GES model.

Type of unit	Notation	Identification	Vintage in GES
Prolonged zero-time units	C^{old}_{t,u,v,p_0}	– Age in 2010 ≤ *lifetime*	WEPP Year[a]
Prolonged one-time units	C^{old}_{t,u,v,p_1}	– Age in 2010 > *lifetime* and – Age in 2010 – *lifetime* ≤ *lifetimeprol*	WEPP Year + *lifetime*
Prolonged two-times units	C^{old}_{t,u,v,p_2}	– Age in 2010 > *lifetime* and – Age in 2010 – *lifetime* > *lifetimeprol* and – Age in 2010 – *lifetime* ≤ 2×*lifetimeprol*	WEPP Year + *lifetime* + *lifetimeprol*
Prolonged *n*-times units	C^{old}_{t,u,v,p_n}	– Age in 2010 > *lifetime* and – Age in 2010 – *lifetime* > (*n*-1)×*lifetimeprol* and – Age in 2010 – *lifetime* ≤ *n*×*lifetimeprol*	WEPP Year + *lifetime* + (*n*-1)×*lifetimeprol*

[a]: WEPP Year = year of commissioning in the WEPP data base.

3.4.2 Identifying the out-of-lifetime units

Before turning to the optimization problem, the model identifies which are the out-of-lifetime power plants at the beginning of each year *t*, using the following rule (see appendix A3 for notations):

$\forall\{t,u,v\}, \forall p \in P \setminus \{p_1, \dots, p_n\}$ with $n > 0$,

$$C_{t,u,v,p}^{old} = \begin{cases} C_{t,u,v,p}^{old,alive}, \ if \ \ t - v \leq lifetime_u \\ \\ C_{t,u,v,p}^{old,dead}, \ if \ \ t - v > lifetime_u \end{cases}, \quad \textbf{(3)}$$

$\forall\{t,u,v\}, \forall p \in P \setminus p_0$,

$$C_{t,u,v,p}^{old} = \begin{cases} C_{t,u,v,p}^{old,alive}, \ if \ \ t - v \leq lifetimeprol_u \\ \\ C_{t,u,v,p}^{old,dead}, \ if \ \ t - v > lifetimeprol_u \end{cases}. \quad \textbf{(4)}$$

3.4.3 Decisions to prolong or decommission the out-of-lifetime units

Once the out-of-lifetime power plants have been identified, the model implements a calculation that allows deciding if it is a profitable option to refurbish and prolong those units, or if it is cheaper to decommissioning it and considering investments in new units.[13] In case of coal, this calculation can be implemented taking into account co-firing or not. When co-firing is taken into account, we have the following rule:

$\forall p \in P \setminus \{p_1, \dots, p_n\}$, $\forall\{t,v\}$, with $lifetime_u < t - v \leq lifetime_u + 1$, $\forall u \in UNC$ and $\forall f \in FNC$ with $UNC \cap FNC \neq \emptyset$,

or,

$\forall p \in P \setminus p_0$, $\forall\{t,v\}$, with $lifetimeprol_u < t - v \leq lifetimeprol_u + 1$, $\forall u \in UNC$ and $\forall f \in FNC$ with $UNC \cap FNC \neq \emptyset$,

$$\left(C_{t,u,v,p}^{old,dead}\right)_{u \in UNC} = \begin{cases} C_{u,v,p,vgp}^{gp}, \ if \quad \sum_{j=t}^{T} LLCOEPROL_{j,u,f}^{t_0} \big/ (T - t + 1) < \sum_{j=t}^{T} LLCOENI_{j,u,f}^{t_0} \big/ (T - t + 1) \\ \\ C_{t,u,v,p}^{old,decom}, \ if \quad \sum_{j=t}^{T} LLCOEPROL_{j,u,f}^{t_0} \big/ (T - t + 1) < \sum_{j=t}^{T} LLCOENI_{j,u,f}^{t_0} \big/ (T - t + 1) \end{cases}, \quad \textbf{(5)}$$

where $vgp = t$, $\forall t + s$ with $s > 0$ (*i.e.* when considering the prolongation decisions of period *t*, the associated *vgp* takes the value of the current *t* for all the remaining time periods).

In addition,

[13] The actual decisions to invest or not in new power plants do not result from this calculation. This only provides information about what is the need to invest in new power plants, given the number of out-of-lifetime units that have prolonged or decommissioned, *ceteris paribus*. On this basis, the actual investment decisions come from solving the optimization problem.

$\forall p \in P \setminus \{p_1, \dots, p_n\}$, $\forall \{t, v\}$, with $lifetime_u < t - v \leq lifetime_u + 1$ and, $\forall u \in UC$, $\forall f \in FC$ and $\forall \{m, b\}$ with $UC \cap FC \neq \emptyset$, $UC \cap MF \cap BAQ \neq \emptyset$, and $m \equiv f$,

or,

$\forall p \in P \setminus p_0$, $\forall \{t, v\}$, with $lifetimeprol_u < t - v \leq lifetimeprol_u + 1$, $\forall u \in UC$, $\forall f \in FC$ and $\forall \{m, b\}$ with $UC \cap FC \neq \emptyset$, $UC \cap MF \cap BAQ \neq \emptyset$, and $m \equiv f$,

$$\left(C_{t,u,v,p}^{old,dead}\right)_{u \in UC} = \begin{cases} C_{u,v,p,vgp}^{gp}, \ if & \begin{array}{c} \sum_{j=t}^{T} LLCOEPROL_{j,u,f}^{t_0,nocf} / (T - t + 1) < \sum_{j=t}^{T} LLCOENI_{j,u,f}^{t_0,nocf} / (T - t + 1) \\ or \\ \sum_{j=t}^{T} LLCOEPROL_{j,u,m,b}^{t_0,cf} / (T - t + 1) < \sum_{j=t}^{T} LLCOENI_{j,u,m,b}^{t_0,cf} / (T - t + 1) \end{array} \\ & \\ C_{t,u,v,p}^{old,decom}, \ if & \begin{array}{c} \sum_{j=t}^{T} LLCOEPROL_{j,u,f}^{t_0,nocf} / (T - t + 1) \geq \sum_{j=t}^{T} LLCOENI_{j,u,f}^{t_0,nocf} / (T - t + 1) \\ or \\ \sum_{j=t}^{T} LLCOEPROL_{j,u,m,b}^{t_0,cf} / (T - t + 1) \geq \sum_{j=t}^{T} LLCOENI_{j,u,m,b}^{t_0,cf} / (T - t + 1) \end{array} \end{cases}, \quad \textbf{(6)}$$

where $vgp = t$, $\forall t + s$ with $s > 0$.

When co-firing is not taken into account, the rule for no coal units (equation **(5)** above) apply for both coal and no coal units.[14]

3.5 Optimization problem

The optimization problem is formed as a dynamic linear programming model, in which a series of yearly decisions is computed for electricity dispatch and investment. The need to extend the generation mix is created by the increasing electricity demand and the decommissioning of some of the out-of-lifetime units. The objective function is a sum of annual costs for electricity generation and investment. The model considers a range of constraints to reflect technical requirements, resources availability, interconnections, co-firing conditions, market-clearing, etc. Figure 1 provides an overview of the GES optimization problem (the full mathematical formulation is available in the online mathematical appendix).

[14] A more detailed presentation is available in the online mathematical appendix. One can also find the LLCOE expressions in this documentation.

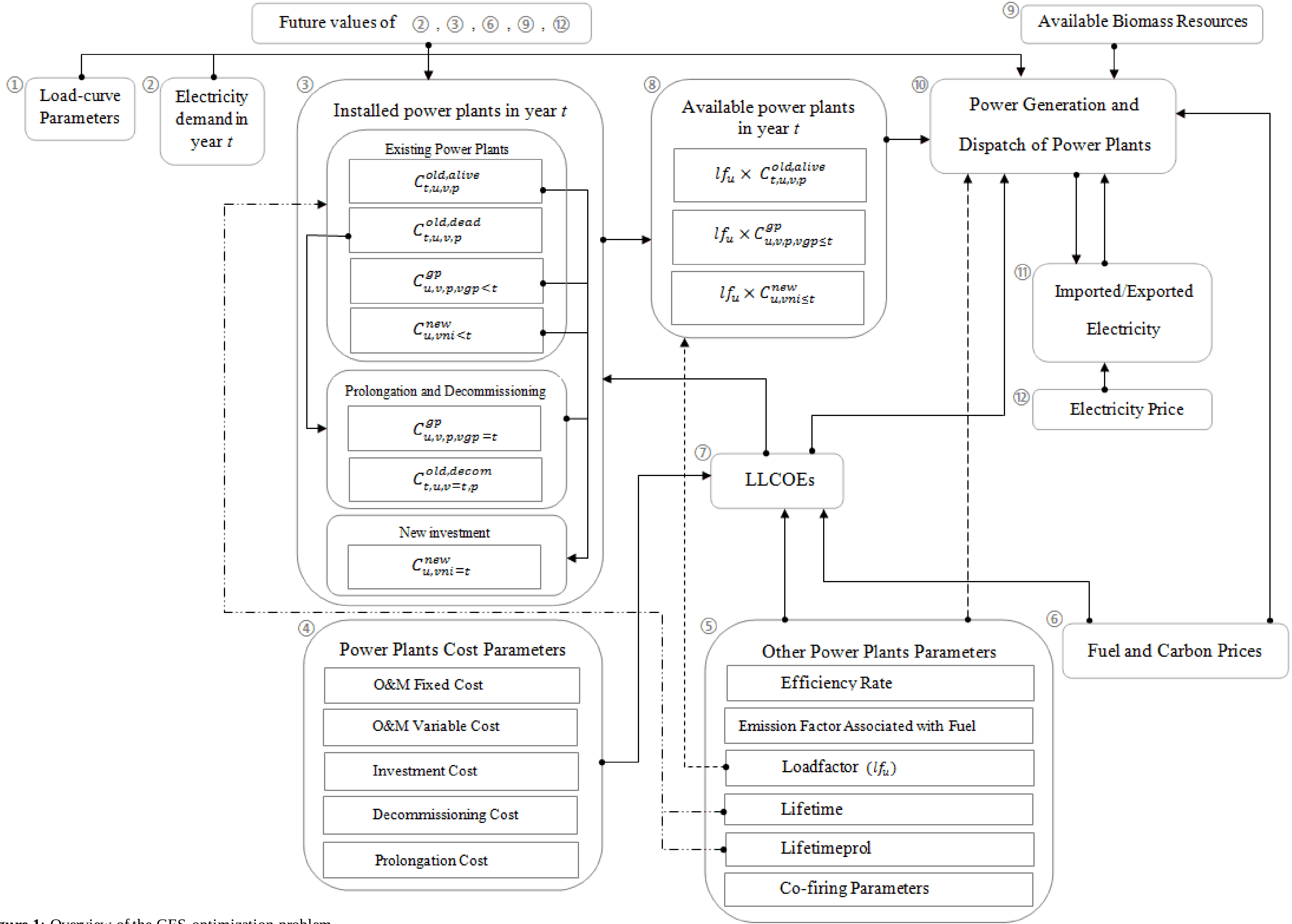

Figure 1: Overview of the GES optimization problem.

4. Application to French power sector

4.1 Data

4.1.1 Installed power capacity

The French power sector is largely dominated by nuclear, which represents more than 50% of installed capacity. Fossil (oil, gas and coal) and hydroelectricity account each for approximately 20% of generation equipments, while renewables (wind, solar, geothermal, and biomass) and waste amount to about 6%. The WEPP data base (Platts, 2009) provides values for generation equipments at the end of 2009. We use these values as proxy of the French generation capacity at the beginning of 2010, the base year in GES (Figures 2 and 3).

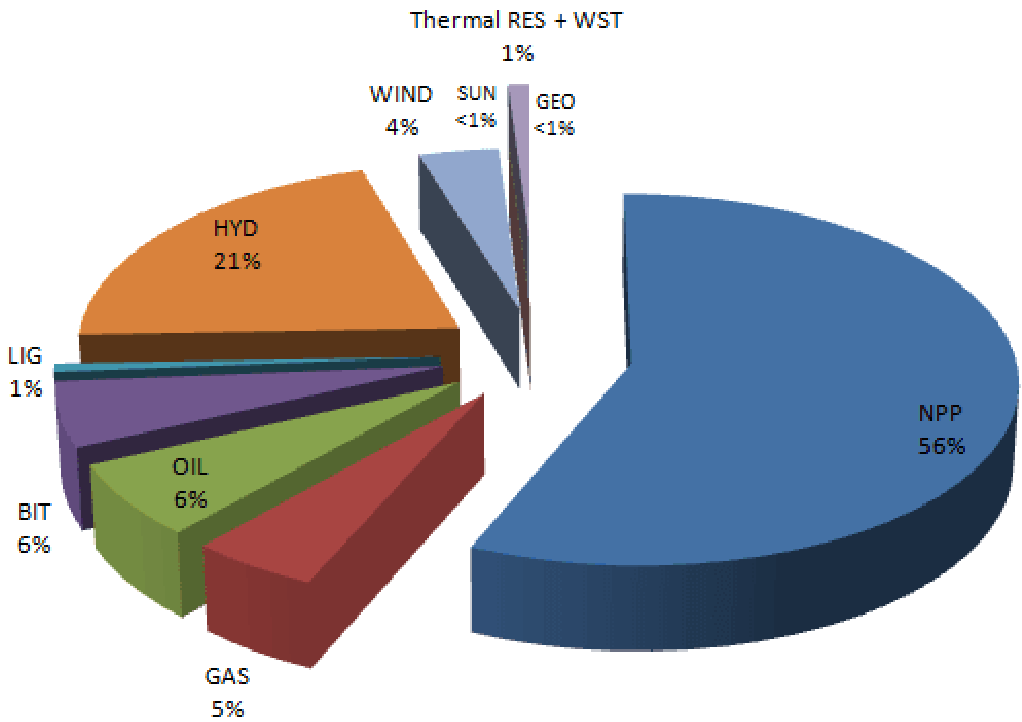

Figure 2: Power generation equipments in the base year 2010.

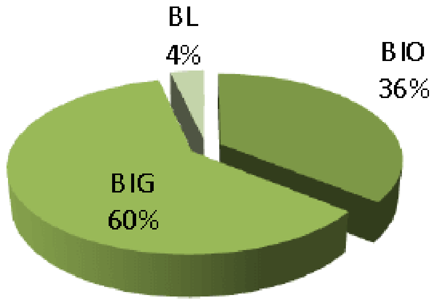

Figure 3: Distribution of the technologies in the thermal RES capacities (base year 2010).

Regarding the transmission capacities for electricity trades at interconnections, we use the 2010 NTC (Net Transmission Capacities) data from the RTE website.[15] We take the sum of all the NTC between France and countries at the border: 13 216 MW for import and 10 109 MW for export. As a simplification, we assume a 150% increase of the transmission capacities by 2050 (Kannan and Turton, 2013), which translates into an Average Annual Growth Rate (AAGR) of 2.3% per year. As a consequence, import (export) capacities would increase to 20 896 (15 984) MW in 2030.

4.1.2 Projections for power demand, fuel and carbon price trends

In order to distinguish between different future evolutions of markets and prices, we use the scenarios from the World Energy Outlook (IEA, 2012): Current Policy Scenario (CPS), New Policy Scenario (NPS), 450 Scenario (450). We use the AAGRs reflecting these three scenarios to compute projections of electricity demand in France over the period 2010-2030. We also compute price trends for EUAs (European Union Allowances, the carbon certificates from the EU ETS), which are indexed on the above mentioned scenarios over the same period. Regarding solid biomass fuels, the price trends are indexed on price projections for solid biomass (Brenner, 2012) and resource mobilization cost (ECF *et al.*, 2010), simultaneously with the oil price evolution from IEA (2012). This allows deriving values associated with each of the IEA (2012) scenarios, which also reflect the expected evolutions in the biomass industry.[16] In all cases, price series reflect (local) European resources. Table 4 gives a summary of the fuel and EUA price projections associated with the CPS and 450 scenarios.

[15] RTE is the French electricity transmission system operator: http://www.rte-france.com/.

[16] The complete price data and indexation methodology is detailed in the online appendix about indexed price trends for fuels, which is available in the following link: Indexed Price Trends_Appendix_GES1.0. As explained above, the price trends have been computed through different indexations applied to different values. In this way, we can derive different price trends by modifying the weights we use in the calculation (*i.e.* the weights attributed to oil price, cost of resource mobilization, and price projections for solid biomass). Basically, we consider two indexations reflecting conservative (low indexation on decreasing costs for resources mobilization) or optimistic (high indexation on decreasing costs for resources mobilization) expectations about the price evolution of solid biomass. One may think that the optimistic would arise with higher probability than the conservative hypothesis, due to technological progress and move towards more structured industry. Accordingly, in order to conserve space, we only report the biomass price form the optimistic hypothesis in this paper, and the associated results. All the biomass price projections associated with all the hypothesis can be found in the online appendix.

Table 4: Fuel and EUA price projections (CPS and 450 scenarios). The prices are expressed in Euros per MWh_{prim} for fuels and in Euros per tonne for CO_2.

CPS Scenario					
	2010	2015	2020	2025	2030
OIL	42.45	51.16	61.56	74.08	89.14
GAS	21.89	26.80	32.77	40.06	48.98
BIT	10.76	12.04	13.47	15.06	16.84
LIG	5.87	6.59	7.40	8.31	9.33
OU	1.64	1.68	1.72	1.76	1.81
BL	49.73	53.55	57.67	62.09	66.86
BIG	40.00	45.33	51.38	58.23	65.99
MGW	4.59	5.52	6.64	8.00	9.62
AR	14.50	14.14	13.78	13.44	13.10
WC	18.00	17.67	17.35	17.03	16.72
WP	27.00	28.37	29.81	31.33	32.92
TOP	30.84	34.23	37.99	42.16	46.79
EUA	15.00	17.51	20.45	23.87	27.87
450 Scenario					
	2010	2015	2020	2025	2030
OIL	43.17	48.04	53.43	59.42	66.09
GAS	22.25	25.21	28.55	32.33	36.61
BIT	11.03	10.95	10.88	10.80	10.73
LIG	5.87	6.21	6.58	6.96	7.37
OU	1.64	1.68	1.72	1.76	1.81
BL	49.73	55.93	62.90	70.74	79.55
BIG	40.00	45.11	50.87	57.37	64.70
MGW	4.59	5.10	5.68	6.31	7.02
AR	14.50	14.13	13.77	13.42	13.07
WC	18.00	17.66	17.33	17.00	16.68
WP	27.00	27.72	28.45	29.20	29.98
TOP	30.84	32.69	34.66	36.75	38.96
EUA	15.00	21.74	31.51	45.67	66.19

Finally, we apply the following emission factors (tCO_2/MWh_{prim}) to compute the CO_2 emissions associated with burning non-carbon-neutral fuels (IPCC, 2006): 0.357 for LIG, 0.339 for BIT, 0.268 for OIL and 0.204 for GAS.

4.1.3 Biomass availability

We use several references in order to get data on resource availability and projections for different solid biomass fuels in France. The AR and WC resources correspond to quantities reported in Panoutsou *et al.* (2009) for the year 2010. In case of TOP and WP, the available quantities have been computed using the production capacity listed in DGEC (2011) for the year 2010. Then, in order to get projections for availability of different resources over the considered period, we apply to the 2010 base values the AAGRs for biomass availability in European agriculture and forest, as reported in Panoutsou *et al.* (2009). A summary of computed projections for France is given in Table 5.

Table 5: Biomass and waste availability in France (GWh_{prim} per year).

	2010	2020	2030
AR	126 418	139 644	154 254
WC	83 895	92 672	102 368
WP	6 569	8 165	9 019
TOP	367	1 318	4 738
BIG	2 419	3 008	3 595
BL[a]	6 933	9 295	12 461
MGW	136 676	150 975	166 770

[a]: Based on the IEA (2006) Reference scenario.

We also include available quantities for other non-solid biomass fuels (BIG and BL) and waste (MGW). The values come from Panoutsou et *al.* (2009) for BIG and MGW, and from IEA (2006) and IEA (2007a) for BL.[17]

4.2 Calibration and validation

The validation process was conducted through a calibration of the dispatch module. We have iteratively adapted the load-factor of each technology (on the basis of values reported in the literature) so as to best replicate the French power generation mix in 2010 (RTE, 2011). Results appear in Figures 4 and 5.

[17] More details about data, calculation and references are given in the online appendix about biomass and waste availability, which is available in the following link: Biomass_and_Waste_Availability_Appendix_GES1.0. In addition, this document provides similar values reflecting biomass and waste availability in the whole Europe (with further references for the data), as the values reported for France in the paper.

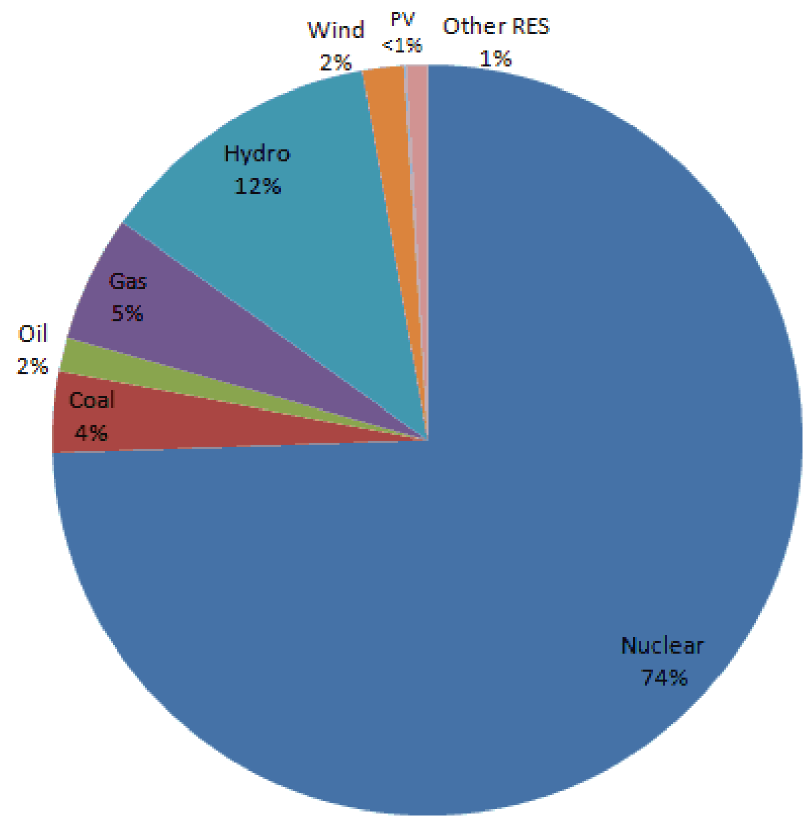

Figure 4: The 2010 French power generation mix (RTE, 2011).

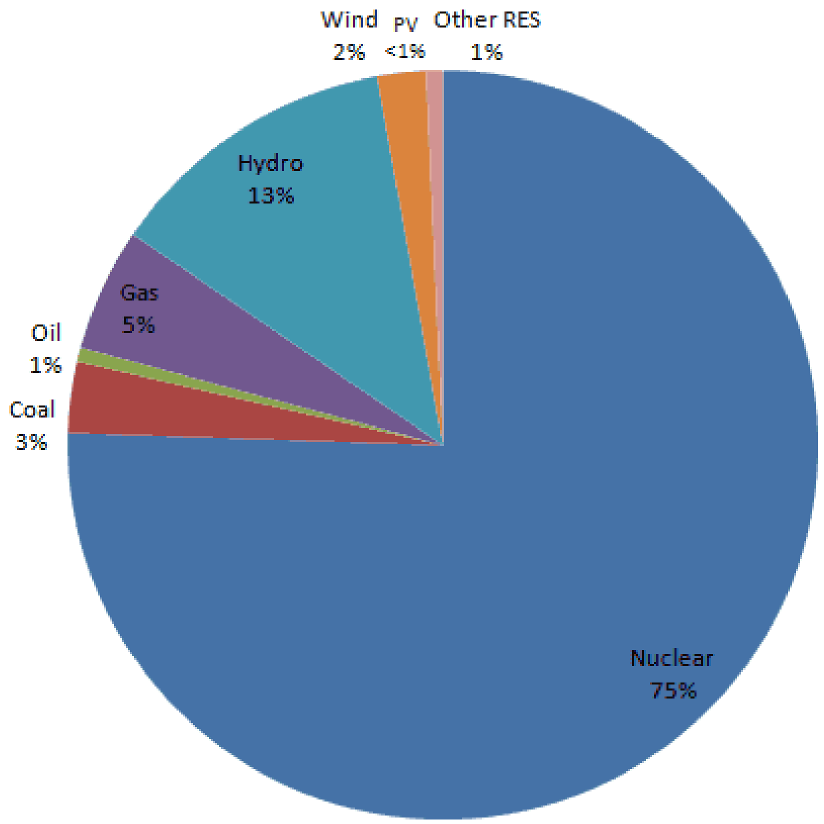

Figure 5: 2010 French power generation mix as computed by the GES model.

Figures 4 and 5 indicate that the model tends to underestimate production from oil and coal (the computed 2010 coal consumption is 45 TWh_{prim} comparing with the 50 TWh_{prim} of coal reported by Eurostat for the 2010 French power generation), whereas contributions of nuclear and hydroelectricity are somewhat overestimated. Nevertheless, the differences are slight, and overall, the model pretty well replicates the 2010 data.

5. Results

A range of analyses have been undertaken for this paper, in order to illustrate the methodology and investigate the consequences of biomass-based electricity in different model settings. Basically, we consider two types of model settings for the simulations, depending on if co-firing and prolongation of out-of-lifetime nuclear power plants are allowed or not.[18] This translates into four cases to investigate: *NPP* with *cf* (when the out-of-lifetime nuclear units can be prolonged and co-firing is allowed), *NPP* with *nocf* (when the out-of-lifetime nuclear units can be prolonged and co-firing is not allowed), *noNPP* with *cf* (when the out-of-lifetime nuclear units cannot be prolonged and co-firing is allowed), *noNPP* with *nocf* (when the out-of-lifetime nuclear units cannot be prolonged and co-firing is not allowed). Furthermore, we run these four cases with different scenarios reflecting the IEA (2012) projections, the implications of high carbon price, and the consequences of accounting for the biomass part of co-firing as a contribution for achieving the RES objective in power generation.

5.1 Base scenarios

The base scenarios correspond to the three scenarios of IEA (2012), as described in section 4.1.2. We do not include any constraint about the share of RES in these base cases. This is examined in section 5.2.3. In order to alleviate the presentation, we only discuss results from the CPS and 450 scenarios. Moreover, when results depend on random events (Table 1), we only report expected values.

[18] In the last few years, political debates have increasingly developed in France about the energy transition and the share of nuclear in the electricity mix. According to the current project of law, the power production from nuclear should be reduced by 25% in 2025. Such arrangement would strongly impact the development of other thermal power technologies, in a country where about 75% of power generation rely on nuclear. In order to account for these effects in our simulations, we run the model with allowing or not the prolongation of the out-of-lifetime nuclear units. This allows investigating how this may impact the share of coal and co-firing in the electricity mix.

5.1.1 Production and generation capacity mix

Unsurprisingly, nuclear dominates power generation in all cases (Figure 6). The contribution of other technologies strongly depends on the ability to prolong or not the out-of-lifetime nuclear units. For example, in the CPS scenario, with *nocf* and *noNPP* settings, the 2030 production of coal and gas units amounts to 192 and 97 TWh_{elec}, respectively, whereas the same values are 77 and 48.1 with *nocf* and *NPP* (the percentage of power production related to these values are summarized in Table 6). In the 450 scenario with the *nocf*, the 2030 production of coal and gas units in the *noNPP* amounts to 80.7 and 128.8 TWh_{elec}, respectively, compared with 24.1 and 40 in the *NPP* setting.

Table 6: Percentage of coal and gas in the total power generation of 2030.

	CPS scenario		450 scenario	
	nocf - noNPP	*nocf-NPP*	*nocf - noNPP*	*nocf-NPP*
Coal	31.6%	11.5%	15.2%	4%
Gas	16%	7.1%	24.2%	6.6%

Indeed, when the prolongation of nuclear is not allowed, the number of active nuclear units decreases as time passes (Figure 7). This creates a need to invest in new capacities in order to maintain the size of the fleet. As we consider a constraint that disallows investment in nuclear, this results into more investments in other technologies that mainly rely on gas and coal (Figures 7 and 8).[19] For example, the 2030 cumulated investments in gas plants with *cf* and *noNPP* settings amount to 37.2 GW (37.6 in *nocf*), for both the CPS and 450 scenarios. In the *NPP* setting, the same values are 16.6 and 8.3 GW in the CPS and 450 scenarios (for both *cf* or *nocf*), respectively. In the same way, the 2030 cumulated investment in coal plants in the CPS scenario with *cf* is 18.1 GW (17.8 in *nocf*) in *noNPP*, and 7.97 GW (7.96 in *nocf*) in *NPP* setting.[20] Additionally, these results indicate that co-firing has a very limited influence on

[19] Whereas the model considers situations in which the out-of-lifetime nuclear power plants can be prolonged, investment is never allowed. This reflects political pressure in France, where construction of new nuclear reactor is very unlikely by 2030, while prolongation of old units is more discussed.

[20] Results indicate that there are very few investments in coal plants in the 450 scenario: 3.3 GW in *cf* (2.9 GW in *nocf*) with *noNPP*, and 1 GW in both *cf* or *nocf* with *NPP*. Moreover, in this case, investments in coal plants only rely on STBITs, whereas all the coal plant technologies are involved in the CPS scenario. Since both the prices of BIT and LIG are lower in the 450 scenario than in the CPS, this decrease in new coal capacities is obviously explained by the carbon price, which is higher in the 450 compared with the CPS. This is illustrated in Figure 11 of section 5.2.1, which shows that investments in coal plants are strongly reduced (and finally disappear), when increasing the carbon price compared with its value in the CPS scenario.

investments in coal plants in these base cases, since the above mentioned values show a very slight difference when moving form *nocf* to *cf* setting. Co-firing also produces small effects on the production of coal plants. For example, moving from *nocf* to *cf* increases the 2030 production of coal plants from 192 (31.6% of production) to 192.7 TWh_{elec} (31.7% of production), when considering the CPS scenario with *noNPP*, and from 80.7 (15.2% of production) to 83.7 TWh_{elec} (15.7% of production), when considering the 450 scenario with *noNPP*. Co-firing can more significantly impact the production and investment decisions for coal plants, when considering a high carbon price (section 5.2.1). Moreover, when a constraint about the share of RES is introduced, co-firing can greatly impact the generation mix, depending on if the share of biomass from co-firing is accounted for as RES or not (section 5.2.2).

Regarding RES (others than hydroelectricity), results show very slight contributions to power generation in the base scenarios, whatever the settings (*cf* or *nocf*, *NPP* or *noNPP*). Indeed, without constraint about the share of RES in power generation, the renewables remain less competitive than conventional technologies. For the same reason, no investment is made in RES in the base scenarios, except in the 450 with *noNPP* setting (Figure 8). In this case, results show some investments in wind. However, the values remain very small compared with conventional technologies: the 2030 cumulated investment in wind is 1 GW in *nocf*, and 0.97 GW in *cf* setting. By contrast, when considering a high carbon price or a constraint on the share of RES, results indicate that numerous investments in RES are undertaken (section 5.2).

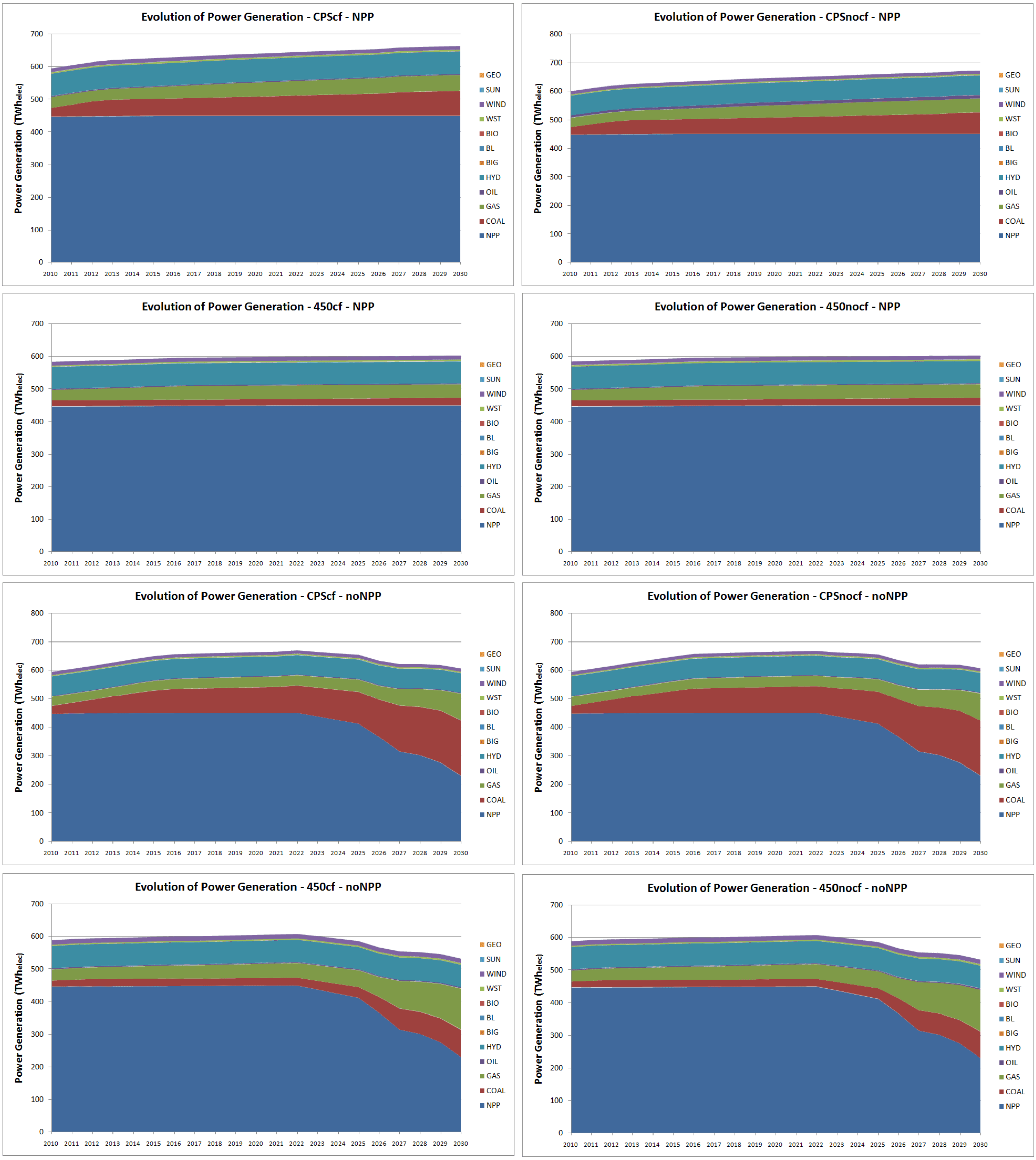

Figure 6: Evolution of the power generation mix for base scenarios in different model settings. *CPScf – NPP* refers to the CPS scenario with co-firing and prolongation of out-of-lifetime nuclear units allowed, *450nocf – noNPP* refers to the 450 scenario with co-firing and prolongation of out-of-lifetime nuclear units not allowed, etc.

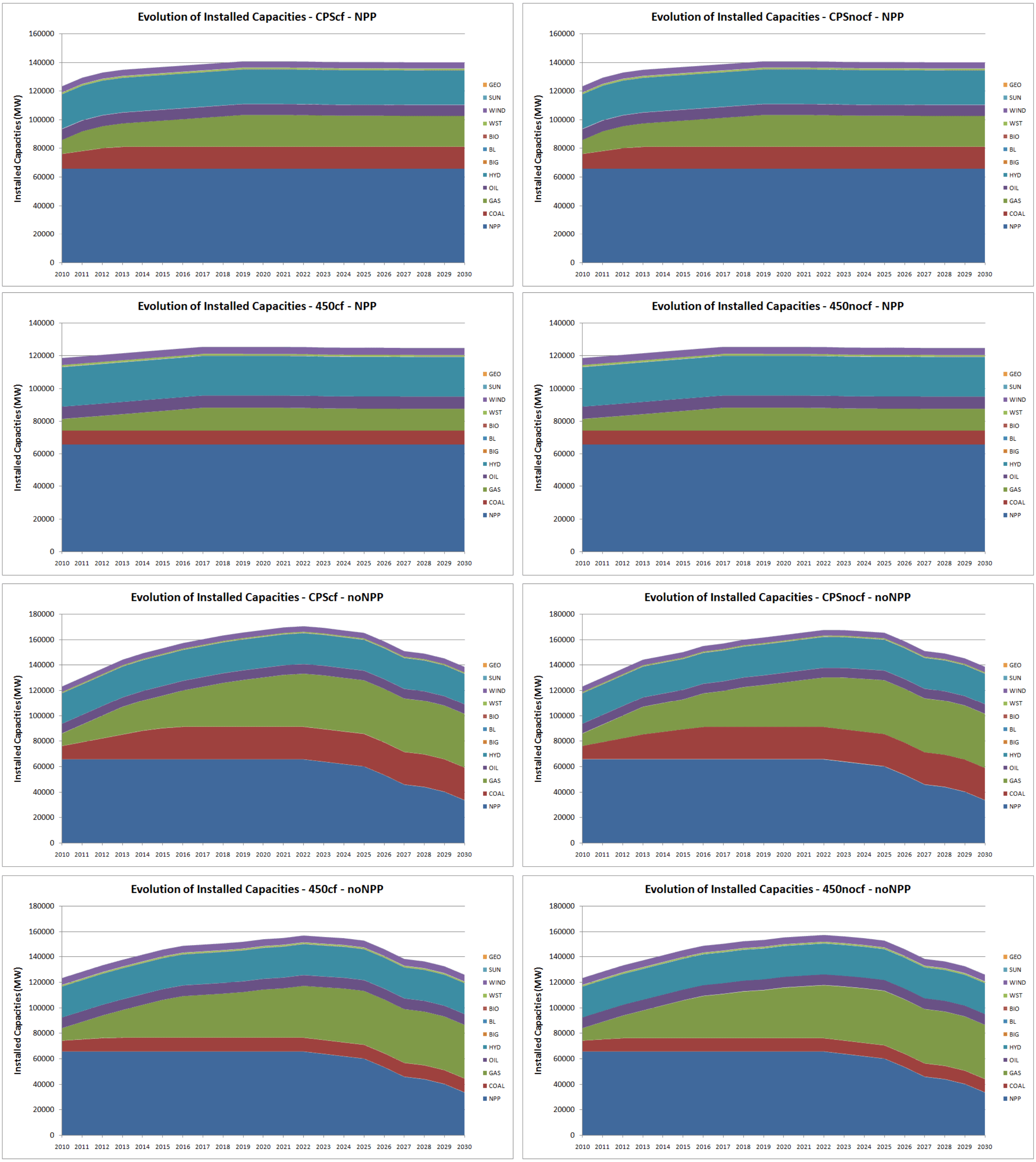

Figure 7: Evolution of the generation capacity mix for base scenarios in different model settings.

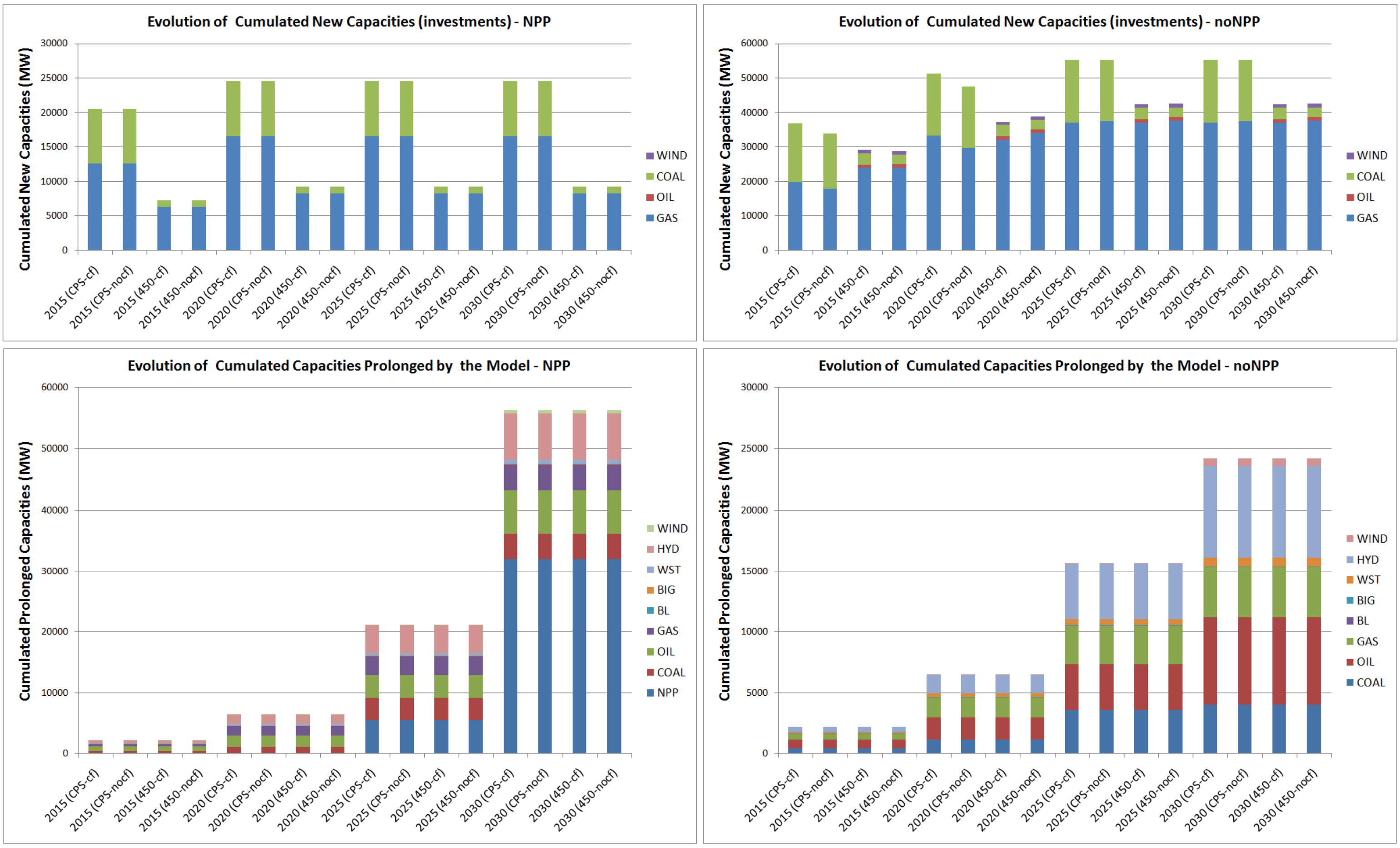

Figure 8: Evolution of cumulated new investments and prolonged (*i.e.* the *gp* units, as computed by the model) capacities. Values for 2015, 2020, 2025, and 2030, in the base scenarios with different model settings.

5.1.2 Biomass consumption

Results indicate that, when co-firing is allowed, it can generate almost all the biomass consumption. Furthermore, the ability to prolong or not the out-of-lifetime nuclear units has also a very significant influence on biomass consumption, since it largely determines the quantity of electricity generated from coal plants. Hence, this is the combination of these two model settings (*cf* or *nocf*, *NPP* or *noNPP*) that determines the magnitude of the biomass demand. This can be summarized as in Table 7.

Table 7: Typical biomass consumption pattern associated with different combinations of the model settings. The "−−" and the "++" stand for the lowest and the highest consumption, respectively. The "−+" and the "+−" are intermediate consumptions with +− > −+.

	NPP	*noNPP*
nocf	−−	−+
cf	+−	++

An overview of biomass consumption results in the base scenarios is depicted in Table 8 (see also Figures 16 and 17 in appendix A1.1).

Table 8: Biomass consumption for the base scenarios in different model settings (TWh_{prim} per year). Values in brackets denote the percentages of demands from co-firing and dedicated biomass power plants in the total biomass consumption.

	2010	2020	2030
		CPS – nocf – NPP	
Biomass All	1.14	1.18	1.29
Biomass Dedicated	1.14 (100%)	1.18 (100%)	1.29 (100%)
Biomass Co-firing	-	-	-
		CPS – cf – NPP	
Biomass All	1.17	3.00	13.00
Biomass Dedicated	1.14 (97%)	1.18 (39%)	1.29 (10%)
Biomass Co-firing	0.03 (3%)	1.82 (61%)	11.71(90%)
		CPS – nocf – noNPP	
Biomass All	1.14	1.13	1.51
Biomass Dedicated	1.14 (100%)	1.13 (100%)	1.51 (100%)
Biomass Co-firing	-	-	-
		CPS – cf – noNPP	
Biomass All	1.17	3.74	32.23
Biomass Dedicated	1.14 (97%)	1.13 (30%)	1.51 (5%)
Biomass Co-firing	0.03 (3%)	2.61 (70%)	30.72 (95%)
		450 – nocf – NPP	
Biomass All	1.10	1.18	1.29
Biomass Dedicated	1.10 (100%)	1.18 (100%)	1.29 (100%)
Biomass Co-firing	-	-	-
		450 – cf – NPP	
Biomass All	1.17	5.48	9.96
Biomass Dedicated	1.14 (97%)	1.18 (22%)	1.29 (13%)
Biomass Co-firing	0.03 (3%)	4.30 (78%)	8.67 (87%)
		450 – nocf – noNPP	
Biomass All	1.14	1.13	1.60
Biomass Dedicated	1.14 (100%)	1.13 (100%)	1.60 (100%)
Biomass Co-firing	-	-	-
		450 – cf – noNPP	
Biomass All	1.17	6.32	24.47
Biomass Dedicated	1.14 (97%)	1.13 (18%)	1.60 (6%)
Biomass Co-firing	0.03 (3%)	5.19 (82%)	22.87 (94%)

The values provided above confirm that co-firing generates much higher biomass demand compared with dedicated biomass units, and, *ceteris paribus*, a higher demand occurs in *noNPP*. Moreover, we observe that the biomass consumption tends to be more significant in the CPS scenario than in the 450. This is explained by a higher co-firing in the CPS scenario due to overall more favorable price conditions, despite the lower carbon price. In this case, differences in the prices of coal and biomass compared with the 450 scenario, combined with the higher electricity demand in the CPS scenario, may explain these differences in co-firing and then in biomass consumption. Prices of coal are higher in the CPS scenario, while the main biomass fuels (AR and WC) have pretty similar prices in the two scenarios (Table 4). Hence, when turning to co-firing in the CPS scenario, substituting biomass for coal generates a greater benefit compared with the 450 scenario because this entails a more significant avoided cost for coal consumption with a similar biomass cost. This makes co-firing profitable with lower levels of carbon prices in this case (Bertrand, 2013). As, in the same time, the electricity demand is higher in the CPS scenario, technologies other than nuclear need to produce more in order to meet demand (Figure 6). Accordingly, coal plants are more solicited in the CPS scenario, with more co-firing and higher biomass consumption.

5.1.3 Co-firing results

Figure 9 shows detailed results on power generation from coal plants in classical (*i.e.* when coal is the only input) and co-firing (*i.e.* when coal and biomass are involved) configurations. [21] It mainly resorts from this that, for a given scenario, different coal technologies do not necessarily use the same configuration (classical or co-firing), and, in case of co-firing, they may use different biomass fuels depending on prices conditions. We observe that, in the 450 scenario, all the 2020 power generation from coal plants is made under co-firing, whereas it is splitted between co-firing and classical in the CPS. This is mainly explained by reduction in the *new* coal capacities in the 450 scenario (that are used under classical configuration in the CPS), due to fewer investments in coal plants in this case (Figure 8). This is also explained by a modification in the 2020 configuration of STLIG units, which turns from classical to co-firing when moving from CPS to 450. First, it is obvious that this change in the STLIG configuration is related to the carbon price increase when considering the 450 scenario rather than the CPS. Furthermore, it is interesting to mention that the two main coal technologies, STBIT and STLIG, do not run the same configuration in the

[21] As the *noNPP* setting gives more pronounced co-firing results, we focus on it in this section, so as to better illustrate the results from GES.

2020 power generation of the CPS scenario, where the STBITs are used under co-firing (Figure 10). The underlying driver of this result is the price difference between the two coal fuels, BIT (hard-coal) and LIG (lignite), which determines why, in this case, co-firing is profitable with BIT whereas it is not with LIG. The higher price of BIT, compared with LIG, makes co-firing with BIT more profitable, *ceteris paribus*, because it entails a greater cost saving from coal consumption when substituting biomass for BIT. In case of LIG, the avoided cost for coal consumption plus the carbon cost saving from co-firing (which is more significant with LIG due to a higher emission factor) are not high enough to compensate the additional cost associated with burning biomass in STLIGs.[22] This is why it is more profitable to run the STLIGs under classical configuration in this case, whereas the STBITs are cheaper under co-firing. This is illustrated in the upper part of Figure 18 (appendix A1.1), which shows the LLCOEs of new investments in STBITs and STLIGs under co-firing or classical configuration in the CPS scenario. Values of the 2020 LLCOEs are sometimes lower with co-firing than under classical configuration for STBITs (with AR and WC), whereas it is never the case with STLIGs.

We already saw that moving from the CPS to the 450 scenarios in 2020, generates co-firing with AR in the STLIGs because of the carbon price increase.[23] Similarly, Figures 9 and 10 indicate that, in the CPS scenario, the STLIGs are used under co-firing with AR in 2030 whereas they were in classical configuration in 2020. The rise in the carbon price between 2020 and 2030 (+36%) is the main driver of this change, that may also be triggered by the increase of LIG price (+26%) and the decrease of AR price (-5%). The influence of the carbon price on co-firing also takes place in decisions about the quality of biomass to be co-fired. Figure 10 provides a detailed overview of biomass consumptions from varying quality for different coal plant technologies in 2030. Interestingly, it shows that increasing the carbon price induces a move towards biomass with higher quality. First, we see that AR is used for co-firing in 2030 with the CPS scenario, whereas it is not in the 450, where WC is preferred (*e.g.* WC is co-fired in STLIGs in the 450 scenario, whereas AR is co-fired in the same units in the CPS). This change cannot be explained by difference in the relative price of biomass fuels with different quality, because both AR and WC have very similar prices in the two

[22] The same result applies here for STBITLIGs as for STLIGs, because, in this case, both technologies are used with LIG. The STBITLIGs can use either BIT or LIG depending on the price conditions. In this case, the coal cost saving from LIG is more significant than the additional carbon cost when burning LIG rather than BIT. Hence, LIG is chosen to feed the STBITLIGs rather than BIT. A higher carbon price can reverse this situation.

[23] Regarding the coal price effect, moving from CPS to 450 translates into a decrease in the price of LIG. With pretty similar prices for AR in both scenarios, this clearly favors classical against co-firing configuration. Accordingly, in this case, the change in the STLIG configuration unambiguously results from the carbon price increase.

scenarios (13.10 against 13.07 Euros for AR, 16.72 against 16.68 for WC). In addition, the price of LIG decreases in the 450 scenario compared with the CPS, which tends to disfavor co-firing against classical configuration (due to a weaker cost saving from coal consumption), and then cannot justify the move from cheap AR to more expensive WC. The high carbon price in the 450 scenario (more than two times the one of CPS in 2030), clearly explains the decision to co-fire WC rather than AR. Indeed, WC is associated with a higher incorporation rate than AR (Table 2), because of its better properties that enable putting more biomass in coal plants without generating more efficiency losses. The higher incorporation rate means that coal plants generate less CO_2 (*i.e.* the value of e_c^{cf} is reduced in equation **(2)**), which reduces the carbon cost from each co-fired MWh_{elec}. Overall, the carbon cost saving with WC is more than the higher biomass cost compared with AR, which makes cheaper running STLIGs with WC rather than with AR. This can be observed when comparing Figure 18 (CPS scenario, appendix A1.1) with Figure 19 (450 scenario, appendix A1.1), where we can see that the 2030 LLCOEs of new STLIGs under co-firing is lower with AR than with WC in the CPS, whereas the reverse is true in the 450 (the same pattern holds for *old* and *gp* units).

As for decision to change the co-fired biomass fuel in STLIGs from AR to WC when moving to the 450 scenario, Figures 10 also indicates that some CHPs (STCHPBITs and STCHPBITLIGs) are used under co-firing with TOP in the 450 scenario, whereas the same units co-fire WC in the CPS. Here again, this change is mainly motivated by higher carbon price in the 450 scenario (simultaneously with lower TOP price compared with the CPS), which makes co-firing with TOP more profitable than with WC due to higher incorporation rate. Other examples of such move for quality can be observed when comparing, for a given scenario, co-firing decisions in different periods associated with different price conditions. Among these results, one can mention modifications of the co-fired biomass fuel from AR, in 2020, to WC, in 2030, for STBITs in the CPS, and STLIGs in the 450. These changes are mainly explained by the rise in the carbon price between 2020 and 2030 (+36% in the CPS, +110% in the 450), which makes co-firing with WC more profitable than with AR due to higher incorporation rate. This is illustrated by values of LLCOEs in Figures 18 and 19 (appendix A1.1). [24]

[24] In order to investigate the effect of modifying the values of the co-firing parameters ρ and inc (with respect to values provided in Table 2), we have run the model with different modification applied to these parameters. In order to converse space, we do not report the results in this paper, but they can be found in the following link: Sensibility Analysis on Co-firing Paramters Appendix GES1.0. Basically, results indicate that modifying ρ produces unambiguous effects, whereas the impacts of variations in inc are uncertain and depend on the price conditions. Nevertheless, the unsteady effects when varying inc do not represent a very significant concern, since uncertainty on co-firing parameters is essentially on the values of ρ.

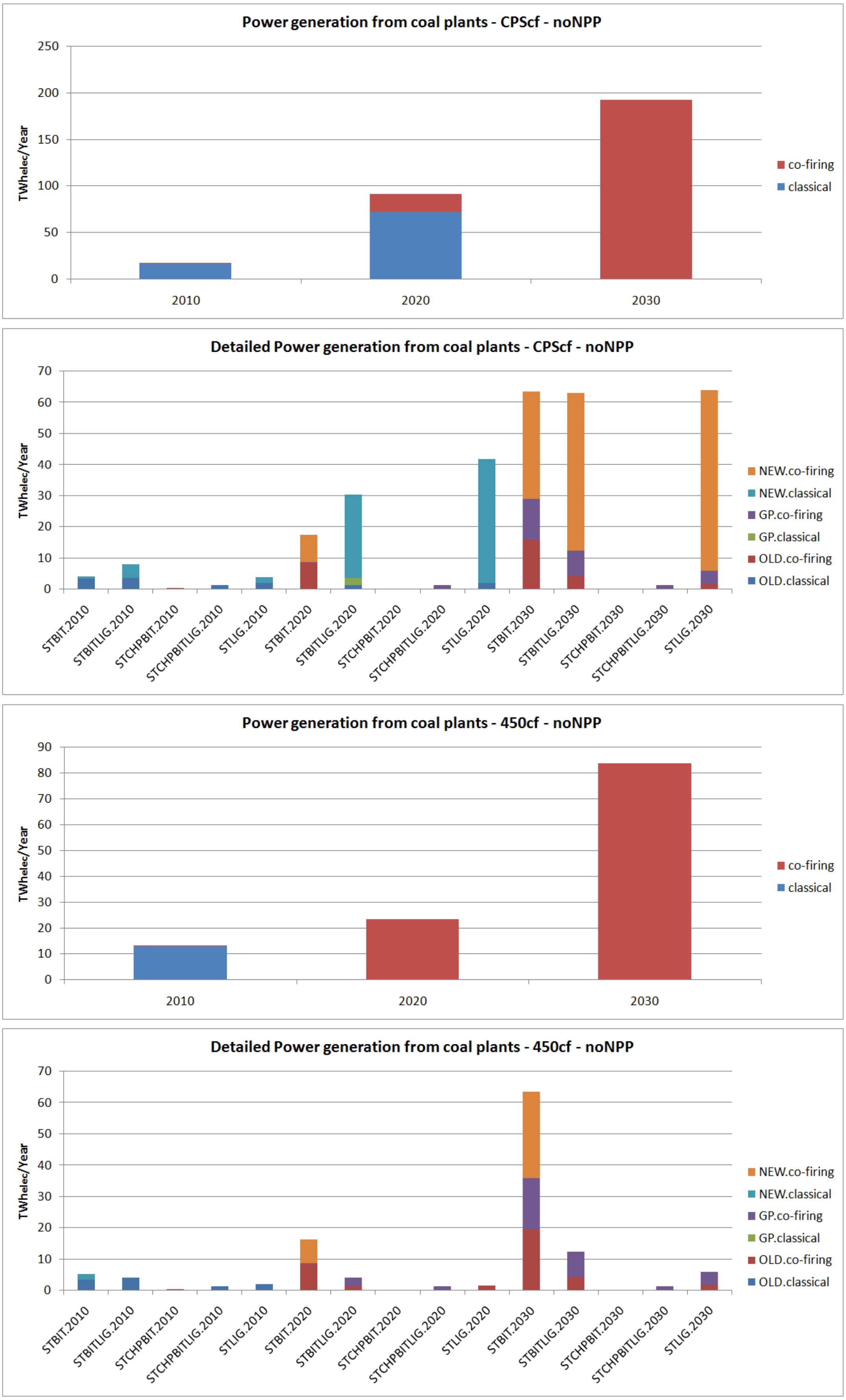

Figure 9: Power generation from coal plants when co-firing is allowed. Values for 2010, 2020, and 2030, in the base scenarios with the *cf* and *noNPP* settings.

Figure 10: Biomass consumption from coal plants under co-firing in 2030. Base scenarios in the *cf* and *noNPP* setting.

5.2 Policy analysis

5.2.1 Carbon price analysis

In order to further investigate how the carbon price can impact results, we ran the model with different fixed values for the carbon price (*e.g.* zero, 50 or 100 Euros per tonne of CO_2). We use the CPS scenario with *noNPP* setting as a reference for this exercise, and we compare the results we obtain from different modified carbon prices. The aim is not to provide precise values associated with different carbon prices, but rather drawing some trends about how modifying the carbon price may impact results.

Regarding power generation, the main effects when increasing the carbon price are a decrease in production from coal plants and rises in production from gas (Table 9, see also Figures 20 and 21 in appendix A1.2).[25] This also generates slight increases in production from dedicated biomass, waste, and bio-liquid, whereas there is no effect on productions from solar, because of very high costs (which remain much higher than all other technologies, even with high carbon prices). Finally, when the carbon price reaches 100 Euros, there are sharp increases in production from bio-gas and wind (Table 9, see also Figures 20 and 21 in appendix A1.2).

Table 9: Power generation from coal, gas, bio-gas, wind, and dedicated biomass power plants (TWh_{elec} per year), in the CPS scenario with *noNPP* and *cf* settings, when considering different modified values for the carbon price. Values in brackets correspond to results we obtain when running the model with the *nocf* setting in similar situations.

	2010	2030
	CPS – cf – noNPP / No carbon price	
COAL	48.10 (48.10)	292.30 (292.30)
GAS	32.50 (32.50)	59.20 (59.20)
BIG	0.09 (0.09)	0.09 (0.09)
WIND	11.40 (11.40)	11.40 (11.40)
BIO (dedicated)	0.23 (0.23)	0.27 (0.27)
	CPS – cf – noNPP / Unmodified carbon price	
COAL	27.30 (27.30)	192.70 (192.00)
GAS	32.50 (32.50)	95.40 (97.00)
BIG	0.09 (0.09)	0.09 (0.09)
WIND	11.40 (11.40)	11.40 (11.40)
BIO (dedicated)	0.23 (0.23)	0.32 (0.32)

[25] Table 9 provides the results associated with the *noNPP* setting. The general shape of results is not modified with the *NPP*. We basically observe the same effects when modifying the carbon price, but they are lesser in magnitude because nuclear remains dominant in the mix.

CPS – cf – noNPP / Fixed 50 Euros carbon price		
COAL	16.00 (15.90)	127.00 (117.40)
GAS	30.50 (30.50)	121.30 (127.10)
BIG	0.09 (0.09)	0.09 (0.09)
WIND	14.00 (14.00)	24.50 (24.50)
BIO (dedicated)	0.24 (0.24)	0.35 (0.35)
CPS – cf – noNPP / Fixed 100 Euros carbon price		
COAL	5.70 (5.60)	25.00 (16.20)
GAS	30.10 (30.10)	106.60 (110.20)
BIG	1.40 (1.40)	56.90 (60.30)
WIND	11.20 (14.00)	25.90 (32.40)
BIO (dedicated)	0.24 (0.24)	0.35 (0.35)

Even though the production from coal plants decreases when the carbon price is increased, Table 9 shows that the reduction is greater when co-firing is not allowed. Co-firing reduces coal plants exposure to carbon price increases, which maintains their profitability. Furthermore, when co-firing is allowed, results indicate that all the power generation from coal plants is made under co-firing in every year when considering fixed 50 or 100 Euros carbon prices (co-firing becomes the only configuration from 2023 on, when the CPS carbon price is not modified). As opposed to what we observe for coal plants, we see that increasing the carbon price increases the power generation from gas, mainly from CCGASs. Because rises in the carbon price more strongly impact coal than gas plants, this tends to increase profitability of CCGASs compared with coal plants.[26] If CCGASs become more profitable, they must switch places with coal plants in the merit order, which results in more production from gas and less from coal.[27] However, by increasing profitability of coal compared with gas, co-firing can lower the benefits from coal-to-gas switching and explain the trend towards more coal and less gas when running the model with the *cf* compared with the *nocf* setting (Table 9). We cannot precisely highlight the influence of co-firing on coal-to-gas switching,

[26] Producing one MWh of electricity usually generates more CO_2 emissions from coal compared with gas plants. However, co-firing can strongly reduce the drawback of coal plants. When considering co-firing with high percentage of (high-quality) biomass in coal plants, the CO_2 emission factors of coal and gas plants can become almost identical. For example, using the efficiency rates of existing STBITs and CCGASs (see online appendix about cost and technical data) with the same CO_2 emission factors for primary energy as presented in section 4.1.2, one can compute that CCGASs and STBITs yield 0.44 and 0.94 tCO_2/MWh_{elec}, respectively. However, when considering the ability to use STBITs under co-firing, the emission rate of STBITs can be reduced to 0.9 (5% incorporation rate with low-quality biomass), and even 0.47 tCO_2/MWh_{elec} (50% incorporation rate with high-quality biomass). See equation for $e_{c,b}^{cf}$ in section 3.3.2.

[27] This reversal in the merit order between coal and gas power plants is well documented in the literature (*e.g.* Delarue *et al.*, 2010; Bertrand, 2012; Solier, 2013).

because such investigation would necessitate reasoning with fixed fleet. Both variations in the carbon price and modifications in the model settings can change the number of available capacities (including coal and gas capacities). Hence, it is difficult to see whether variations in generation from coal and gas during a given hour are explained by modifications in switching or by the composition of the fleet.[28] However, looking at the marginal costs (computed in a similar fashion as in equation **(3)**) we see that co-firing can modify the merit-order of coal and gas plants, so that switching that would exist with coal plants under classical configuration, may be no more profitable when co-firing is implemented.[29] As an illustration, let us consider the marginal costs associated with existing (*old* or *gp*) CCGASs and STBITs, under classical and co-firing configurations, for the year 2019, in the CPS scenario with 50 Euros or unmodified carbon price. Results indicate that STBITs are cheaper than CCGASs with the unmodified carbon price (19.82 Euros per tonne of CO_2), with both classical and co-firing configurations: 64.6 Euros par MWh_{elec} for CCGASs, against 51 (classical configuration), 50.8 (co-firing with WC), or 50.6 (co-firing with AR) for STBITs. With a 50 Euros carbon price, CCGASs become cheaper than STBITs under classical configuration, but remain more expensive when considering co-firing (which prevents the coal-to-gas switching that would exist without co-firing): 75.8 Euros par MWh_{elec} for CCGASs, against 77.3 (classical configuration), 74.6 (co-firing with WC), or 75.7 (co-firing with AR) for STBITs.[30] This shows that co-firing can change the merit-order of coal and gas plants, and may modify the switching decisions between these units. This is an interesting question that may be investigated with the model by turning off the investment and decommissioning/prolongation modules.

Investment results also exhibit the same trend towards more gas and less coal when the carbon price increases. This is illustrated in Figure 11.

[28] For example, in 2020, when considering the *NPP* setting, moving from the unmodified CPS to the CPS with a 50 Euros carbon price increases the generation capacities by 4 GW for wind and 1 GW for CCGAS, with both *cf* and *nocf*, whereas the STBIT capacities are reduced in the *nocf* (by 0.2 GW) and increased in the *cf* (by 1 GW).

[29] These results confirm some preliminary investigations in an early version of GES (see Le Cadre *et al.*, 2011).

[30] Results indicate that moving from the unmodified CPS to the CPS with a 50 Euros carbon price increases the 2019 generation of STBITs in each of the l_2S_1 hours (intermediate load levels in winter) from 5629 to 6579 MW (in the medium demand event for electricity, Table 1), in the *NPP* with *cf*, whereas this reduces the same values from 5629 to 5424 MW in the *NPP* with *nocf*. This is an interesting result with the simultaneous effect of co-firing on the merit-order of coal and gas plants, as described above. However, as explained earlier, this is difficult to see which part of this change is due to the influence of co-firing on the marginal costs, and which one is due to modifications in the fleet.

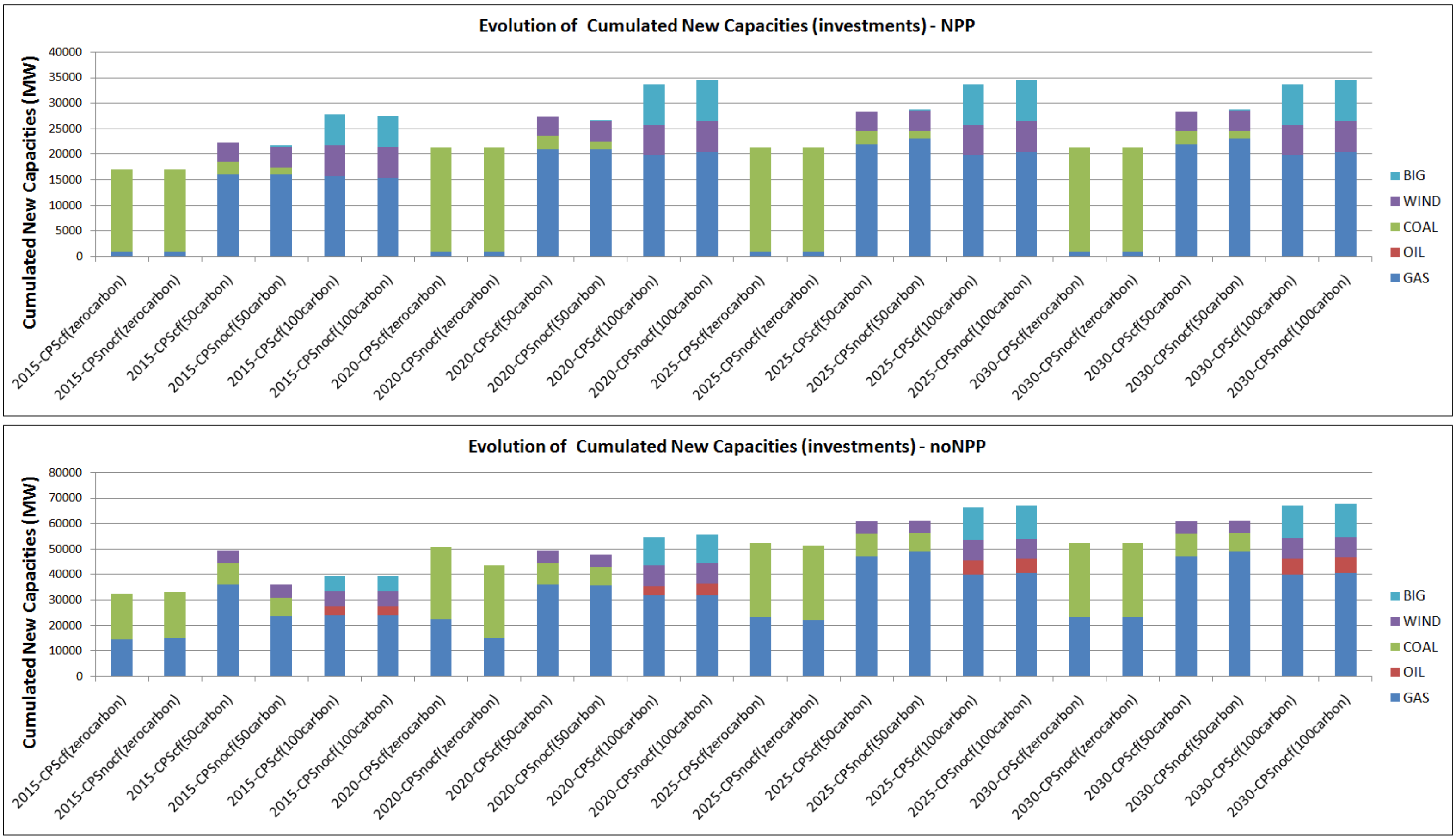

Figure 11: Evolution of cumulated new investments with different modified values for the carbon price in the CPS scenario with different model settings.

Interestingly, results show that more investments in coal are undertaken with the *cf* setting, *ceteris paribus*. For example, the 2030 cumulated investment in coal when considering a fixed 50 Euros carbon price is 8.6 GW, with *cf* and *noNPP*, and 7.2 GW, with *nocf* and *noNPP*. This illustrates again this influence of co-firing on the coal plants profitability. Figure 11 also indicates that a 100 Euros carbon price produces investments in wind and bio-gas. Increasing the carbon price may also modify decisions about prolongation or decommissioning of the out-of-lifetime coal plants (Figure 22, appendix A1.2). In this case, the decisions also depend on the ability to use coal plants under co-firing. This is analyzed in section 5.2.2.

Regarding biomass consumption, results indicate that the carbon price is an important driver (Figure 12, see also Figures 23 and 24 in appendix A1.2).

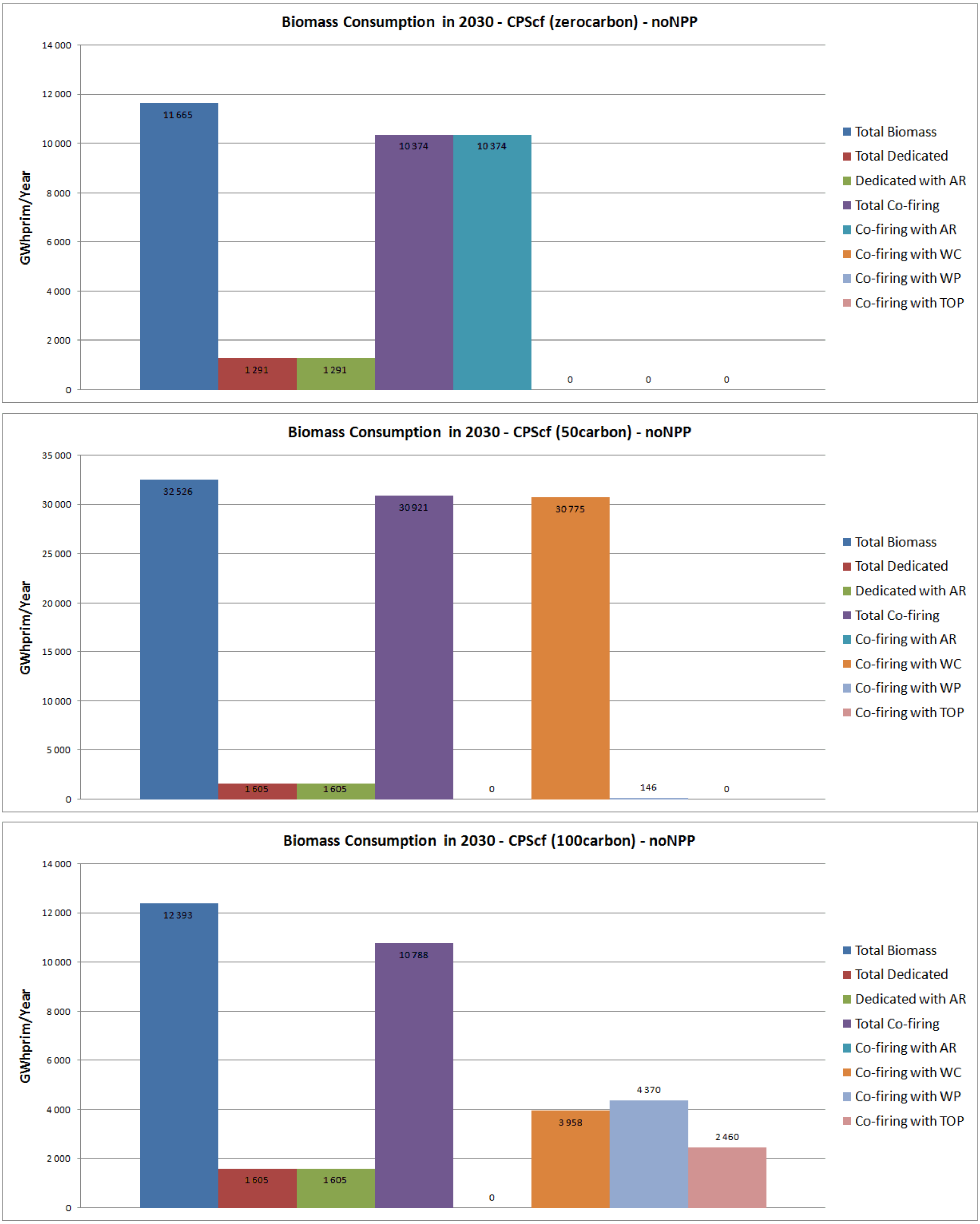

Figure 12: Detailed 2030 biomass demand with different modified values for the carbon price in the CPS scenario with *cf* and *noNPP* settings.

The influence of the carbon price appears in the evolution of biomass demand from co-firing, which represents between 90 and 95% of the total biomass demand in all cases. By comparison, the biomass demand associated with dedicated biomass units is weak (when running simulations with the *nocf* setting, we get the same values from dedicated units as in Figure 12). From zero to 50 Euros carbon price, the biomass demand increases. For example, the total biomass demand in 2030 is 11.7 TWh_{prim} with zero carbon price, 32.2 with unmodified CPS carbon price, and 32.5 with 50 Euros carbon price. By contrast, when the carbon price is 100 Euros, the total biomass demand is reduced compared with results we obtain with a 50 Euros carbon price. This is explained by a sharp reduction in the power generation from coal plants in this case, because co-firing (in the same way as gas) becomes substantially less profitable than alternative technologies that do not emit CO_2 emissions such as wind and bio-gas. However, the diminution is less significant in the biomass demand (-62%) than in coal plants generation (-80%). This results from a move for quality with a high carbon price (as discussed in section 5.1.3), which induces more demand for high-quality biomass with high incorporation rates.

5.2.2 Co-firing and prolongation or decommissioning of out-of-lifetime coal plants

Since the profitability of co-firing may heavily depend on the cost for CO_2 emissions, we investigate here the consequences for prolongation and decommissioning decisions when increasing the carbon price (*i.e.* we apply different values for the carbon price to equations **(5)** and **(6)**). Results are summarized in Figure 13 (see also Figures 25, 26, and 27 in appendix A.1.2).

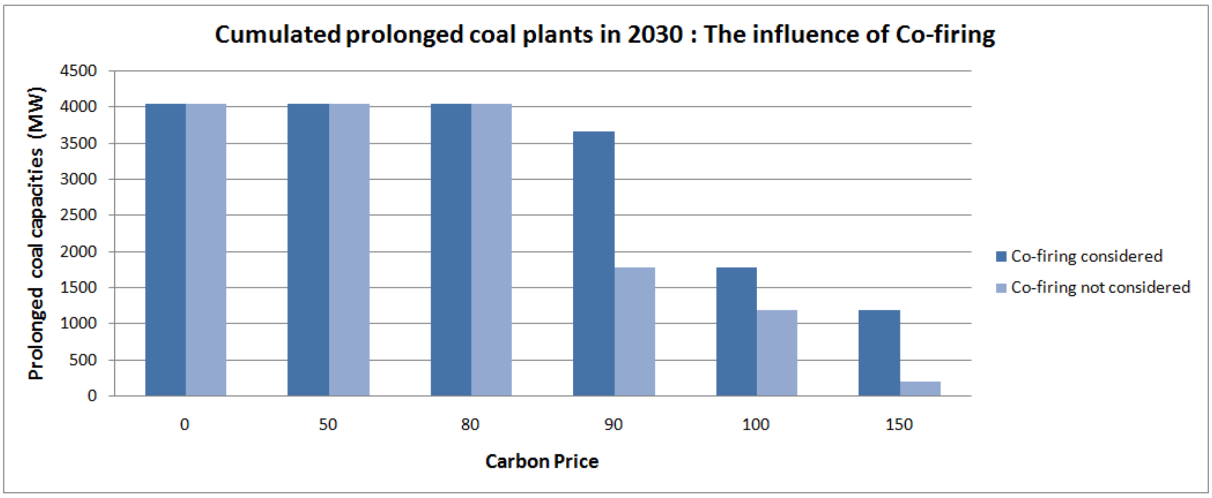

Figure 13: Influence of co-firing on the cumulated volume of prolonged (*gp*) coal capacities in 2030, when considering different modified values for the carbon price in the CPS scenario.

First, Figure 13 shows that the carbon price may impact the prolongation and decommissioning decisions, regardless of the influence of co-firing. Even though this corresponds to very high values for the carbon price, results indicate that when the carbon price reaches 90 Euros, some of the out-of-lifetime coal plants are no more prolonged. This intensifies when the carbon increases beyond this value.

Second, Figure 13 also exhibits an effect of co-firing on these decisions, which induces prolonging units that would be decommissioned without considering co-firing (see 90, 100, 150 Euros carbon prices in Figure 13). For example, with a 90 Euros carbon price, part of the STBITs is prolonged when considering co-firing whereas they would not without co-firing (Figure 25, appendix A.1.2). Similarly, some STLIGs are prolonged with a 100 Euros carbon price when co-firing is accounted for into decisions, whereas they would not otherwise (Figure 25, appendix A.1.2).

Results indicate that co-firing and the carbon price exert a joint influence on the prolongation/decommissioning decisions. In order to explain this, two effects have to be compared: a capital effect, which benefits to prolongation (due to lower capital cost compared with new investments), and an efficiency effect, which benefits to new investments (due to higher efficiency rates compared with prolonged units). When the carbon price is low, the capital effect tends to dominate the efficiency effect, because the carbon expense is relatively weak in this case. Hence, the lower carbon cost with new investment (due to higher efficiency rates) is not enough to compensate the lower capital cost with prolonged units. This is what we observe in Figure 13 when the carbon price is no more than 80 Euros. In this case, all the out-of-lifetime coal plants are prolonged since prolongation is still cheaper than similar new investments, no matter if co-firing is accounted for in decisions or not (Figure 27, appendix A.1.2). By contrast, when the carbon price becomes high enough, the efficiency effect may dominate the capital effect, so as it may be cheaper to invest in new coal plants rather than prolonging the out-of-lifetime units. This is what happens in Figure 13 when the carbon price reaches 90 Euros. In this case, some of the out-of-lifetime coal plants that were prolonged with a lower carbon price are decommissioned. However, taking into account co-firing may modify the results, so that prolongation remains cheaper than new investment (*i.e.* the capital effect remains more significant than the efficiency effect despite the high carbon price) for some coal plants. This is illustrated in Figure 26 in appendix A.1.2. As a consequence, part of the coal plants that would be decommissioned without co-firing are still prolonged. This is what happens for the main part of STBITs with a 100 Euros carbon price, which is prolonged with co-firing whereas they would be decommissioned otherwise (Figure 25, appendix A.1.2).

5.2.3 RES obligation and co-firing

Another interesting topic to explore with the model is the question of how co-firing would impact the electricity mix if it is recognized as a contribution to achieve the RES objective. In this case, the biomass part of the primary energy that is burned in coal plants under co-firing would be accounted for as RES. This does not correspond to the current legislation in most the EU countries, however this constitutes an interesting prospective analysis since co-firing is often pointed out as a low-cost opportunity to increases the share of RES in power generation.[31]

In order to investigate this question, we add an additional constraint to the optimization problem that assigns a mandatory target regarding the share of RES in the overall electricity production (*i.e.* 27% for France as of 2020; MEEDDM, 2008). We apply this constraint with two different settings depending on whether co-firing is accounted for as a RES (*REScf* setting, which corresponds to the optimization problem with constraint **(c.35)**) or not (*RESnocf* setting, which corresponds to the optimization problem with constraint **(c.34)**). In the first case, we add the electricity associated with the biomass part from co-firing (*i.e.* the product between the biomass consumptions from co-firing and the associated efficiency rates, $\eta_{c,b}^{cf}$) to the sum of all the RES power generation. As an illustration, we present in this paper the results we obtain when applying this to the CPS scenario.

Results confirm the intuition that recognizing co-firing as a contribution to the RES objective may greatly modify the electricity mix. Unsurprisingly, results from the *RESnocf* setting show a sharp increase in the RES capacity and generation, compared with what we obtain in the base CPS with no constraint on the share of RES (section 5.1). By contrast, results from the *REScf* setting are similar to those from the base CPS. This is illustrated in Table 10 and Figures 14 and 15 for the *noNPP* setting (see also Figures 28 and 29 in appendix A.1.2). In this case, recognizing the biomass part of co-firing as RES leads to the substitution of coal for wind and bio-gas compared with the *RESnocf* setting. Hence, such a policy arrangement for co-firing would maintain the share of coal in the power mix. While this would help increasing the share of RES in the short run, this may be a concern for social acceptability in the longer run.

[31] The UK is among the few EU countries that recognize co-firing as a contribution to RES power generation. Notably, Renewables Obligation Certificates (ROCs) are now attributed to electricity generated in coal plants under co-firing with biomass. In this case, the ROC rate (ROC per MWh_{elec}) is lower than that of dedicated biomass power plants. See Alexander *et al.* (2013).

Table 10: Main results from coal, bio-gas, and wind, in CPS scenario with *cf* and *noNPP*, when considering different settings regarding the share of RES in power generation: no constraint (base case), *REScf*, and *RESnocf* (with *cf* and *nocf*). Values in brackets correspond to results we obtain when running the model in the *nocf* setting with the same prices.

	Power Generation (TWh_{elec} per year)					
	2010			2030		
	Base Case	*REScf*	*RESnocf*	*Base Case*	*REScf*	*RESnocf*
Coal	27.3 (27.3)	27.3	27 (27)	192.7 (192)	192.7	111 (108.9)
Bio-gas	0.09 (0.09)	0.09	0.4 (0.4)	0.09 (0.09)	0.09	49.6 (49.4)
Wind	11.4 (11.4)	11.4	14 (14)	11.4 (11.4)	11.4	42.9 (42.9)
	Total Installed Capacities (GW)					
	2010			2030		
	Base Case	*REScf*	*RESnocf*	*Base Case*	*REScf*	*RESnocf*
Coal	10.5 (10.5)	10.5	10.5 (10.5)	25.6 (10.5)	25.6	14.2 (7.5)
Bio-gas	0.1 (0.1)	0.1	1.1 (1.1)	0.1 (0.1)	0.1	16.1 (17.5)
Wind	4.3 (4.3)	4.3	5.3 (5.3)	4.3 (4.3)	4.3	16.3 (16.3)
	Cumulated New Capacities (GW)					
	2010			2030		
	Base Case	*REScf*	*RESnocf*	*Base Case*	*REScf*	*RESnocf*
Coal	3 (3)	3 (3)	3 (3)	18 (17.9)	18	6.7 (6.4)
Bio-gas	- (-)	- (-)	1 (1)	- (-)	-	16 (15.9)
Wind	- (-)	- (-)	1 (1)	- (-)	-	12 (12)

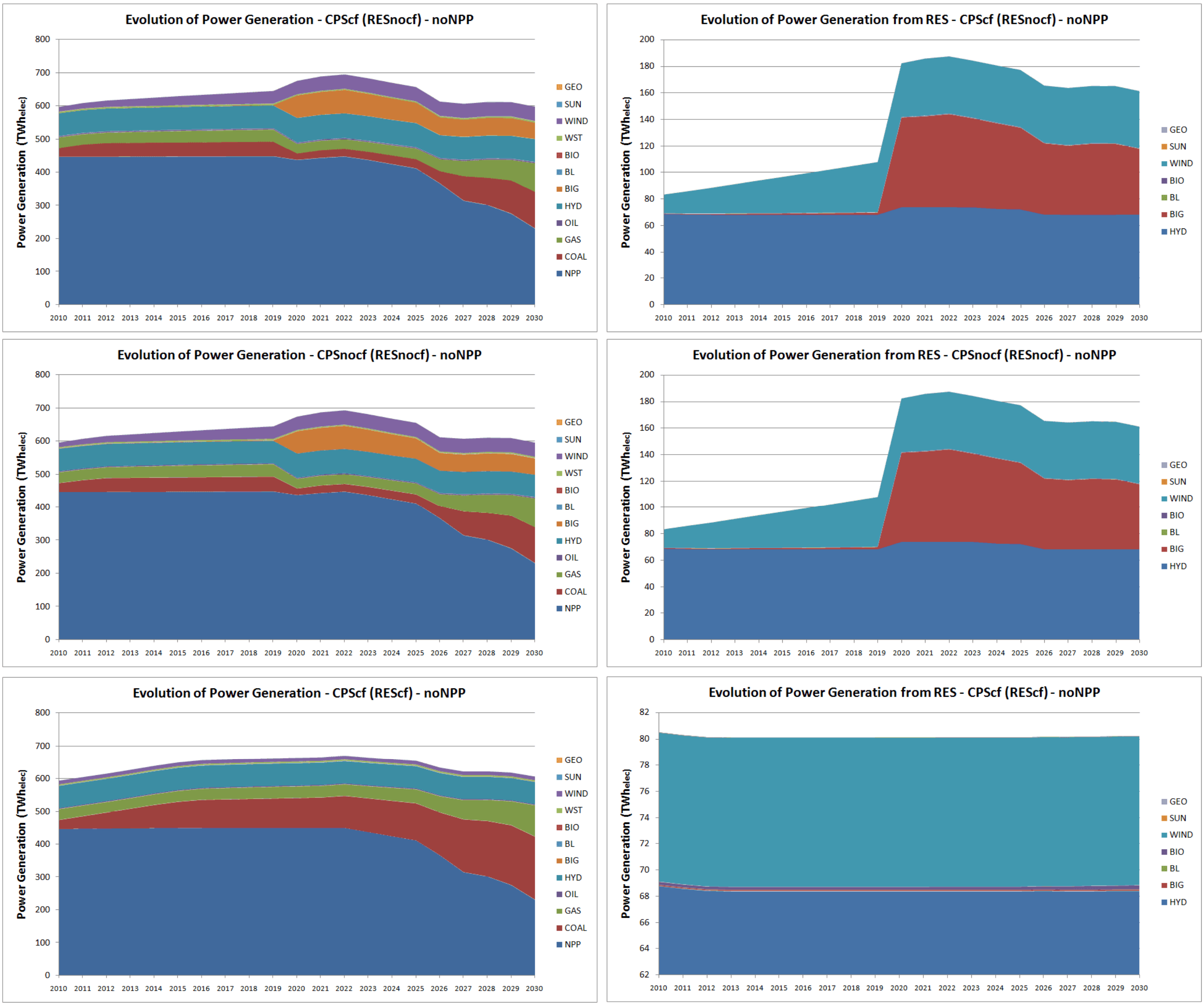

Figure 14: Evolution of the power generation mix in the *noNPP* setting, with a constraint on the share of RES in the total power generation in the CPS scenario. *RESnocf* (with *cf* and *nocf* settings) corresponds to the case in which co-firing is not recognized as a RES, whereas it is in the *REScf*.

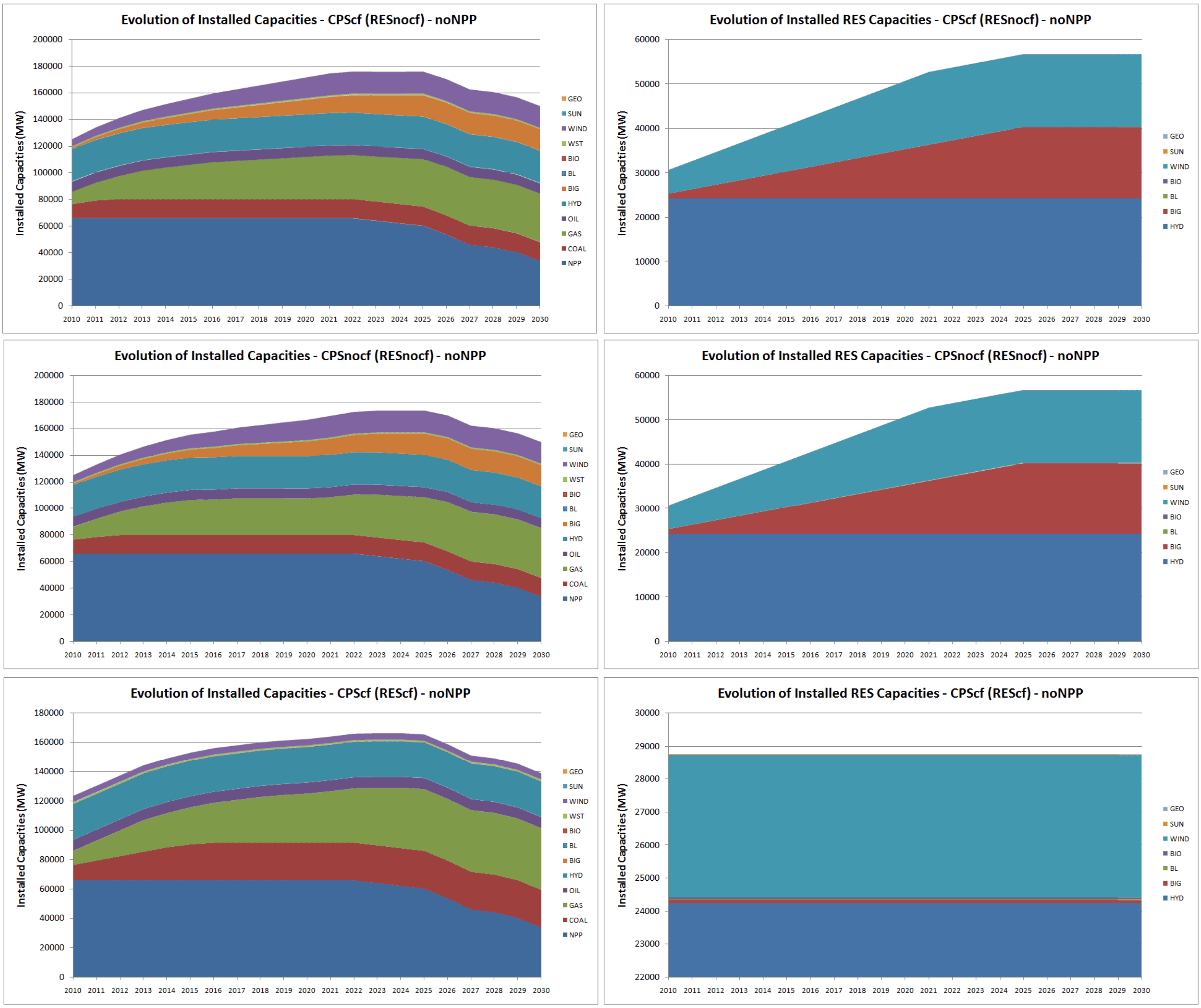

Figure 15: Evolution of the generation capacity mix in the *noNPP* setting, with a constraint on the share of RES in the total power generation in the CPS scenario. *RESnocf* (with *cf* and *nocf* settings) corresponds to the case in which co-firing is not recognized as a RES, whereas it is in the *REScf*.

More surprisingly, results indicate that the RES power generation and capacity are increased for both the *RESnocf-nocf* (*i.e.* when co-firing is neither recognized as RES nor allowed) and the *RESnocf-cf* (*i.e.* when co-firing is not recognized as RES whereas it is allowed) when considering the *NPP* setting rather than the *noNPP* (Figures 28 and 29, appendix A.1.2). This means that more RES are involved when the prolongation of out-of-lifetime nuclear units is allowed, which seems counter-intuitive. This is actually the consequence of the higher power generation from conventional technologies due to more nuclear capacities in this case, compared with the *noNPP*. For example, in the *RESnocf-cf* setting, the total power generation from conventional technologies (*i.e.* all the power technologies except the RES) in 2030 is 502.92 TWh_{elec} with the *NPP*, whereas it is 436.33 with the *noNPP*. Hence, in order to reach 27% of RES in the total electricity production (the mandatory percentage in France), the total power generation from RES has to be more significant in the *NPP*: 185.22 TWh_{elec} compared with 161.38 in the *noNPP*. This also translates into more investments in RES with the *NPP* than with the *noNPP*. Notably, these are the only model settings that generate investments in dedicated biomass power plants: about 1.5 GW of cumulated new STBIO capacities in 2011 for both the *RESnocf-cf* and *RESnocf*-no*cf* with the *NPP*. Accordingly, the power generation from dedicated biomass units is more significant than in any other model setting: 9.5 TWh_{elec} in 2030 for both the *RESnocf-cf* and *RESnocf*-no*cf* with the *NPP* (the same value ranges from 0.27 to 0.32 TWh_{elec} in the base CPS), which is associated to 27.7 TWh_{prim} of (AR) biomass in dedicated biomass power plants (89% of the total biomass demand in the *RESnocf-cf*).

6. Conclusions

This paper presents the version 1.0 of GES, which is a simulation model that has been designed to investigate questions related to biomass-based electricity in the European countries, with a special focus on the biomass co-firing in coal plants. The model allows assessing the consequences of co-firing, carbon price and RES policies on the share of biomass in the electricity mix, the competition between different types of biomass with unequal qualities, investments or decisions about decommissioning or prolongation of out-of-lifetime coal plants. To the best of our knowledge, no other model provides a so comprehensive analysis of biomass-based electricity and co-firing. Interestingly, the GES model offers an original tool to investigate the indirect consequences of biomass-based electricity through couplings with models for availability of biomass resources, land use, or biomass supply to competing consumer sectors.

We extend previous works in the literature in essentially three directions. We provide the first simulation model for electricity that takes into account the biomass co-firing in coal plants with a wide range of induced effects. Notably, we represent the impact of biomass quality on the conversion efficiency of coal plants under co-firing configuration. Among the main results, we show that co-firing may increase the share of coal in the electricity mix, but its influence remains slight in the base scenarios and the actual contribution of coal (as that of other non-nuclear technologies) heavily depends on the ability to prolong or not the out-of-lifetime nuclear units. Results indicate that co-firing can more significantly impact the production and investments from coal plants when considering higher carbon prices than in the base scenarios. In all cases, co-firing generates a much more significant biomass demand (often close to 90% of the total demand) compared with dedicated biomass power plants. In addition, we find that increasing the carbon price generates a move towards quality that induces consuming more high-quality biomass (*e.g.* WP or TOP) with high incorporation rates.

Second, we analyze the effect of co-firing on decisions about prolongation or decommissioning of out-of-lifetime coal plants. Results indicate that co-firing exerts a joint influence with the carbon price. On the one hand, some of the out-of-lifetime coal plants that are prolonged with a low carbon price tend to be decommissioned when the carbon price is increased. On the other hand, taking into account co-firing may encourage to prolonging units that would be decommissioned otherwise. However, even though co-firing is able to increase the share of coal in the electricity mix, a high carbon price can heavily weaken its influence with much fewer prolongations and investments in coal plants.

Finally, we investigate the consequences of recognizing co-firing as a contribution to achieve the RES objectives in power generation. Results show that this can greatly modify the electricity mix. Indeed, whereas recognizing co-firing as a renewable may offer efficient opportunities to manage the short run development of RES in power generation, this may also maintain the share of coal in the power mix. In the longer run, this may be a concern, as maintaining a high share of coal would raise issues for social acceptability. At least, if agreed, such arrangement for co-firing would necessitate additional policy instruments so as to alleviate the incentive to rely too much on coal. Among these policies, a strong carbon market appears as a good driver to accelerate a more ambitious transition towards more RES in electricity.

In summary, this paper provides an extensive overview of the version 1.0 of the GES model, with an application to the French power generation. Overall, the results indicate that the biomass demand from co-firing is much greater than that from dedicated biomass units, and that co-firing can heavily influence the composition of the fleet under certain circumstances and policy arrangements. In the current 1.0 version, the GES model is made up of different modules for different European countries, which allows easily implementing the same simulations for other countries as for France in this paper. This will be a matter for further analyses based on the model. An avenue for future developments would be connecting all the country modules into a single model. This would allow investing the development of biomass-based electricity simultaneously at the EU level, with potential competition between countries to access the biomass resource.

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Appendix A1: Additional Figures and Tables.

A1.1 Base Scenarios

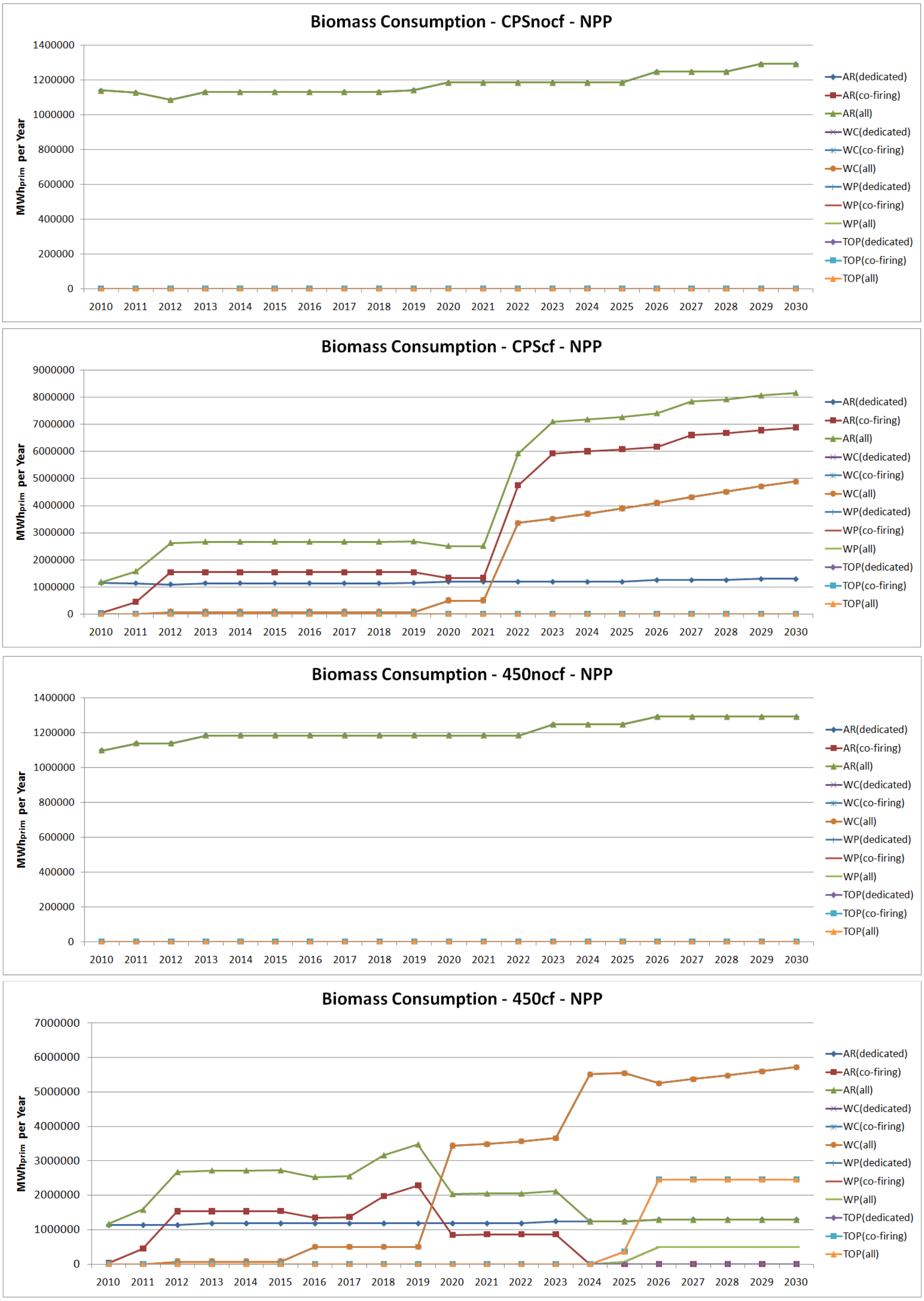


Figure 16: Evolution of biomass consumption in dedicated and coal power plants. Values for the base scenarios in the *cf* and *nocf* model settings, when prolongation of out-of-lifetime nuclear units is allowed (*NPP*).

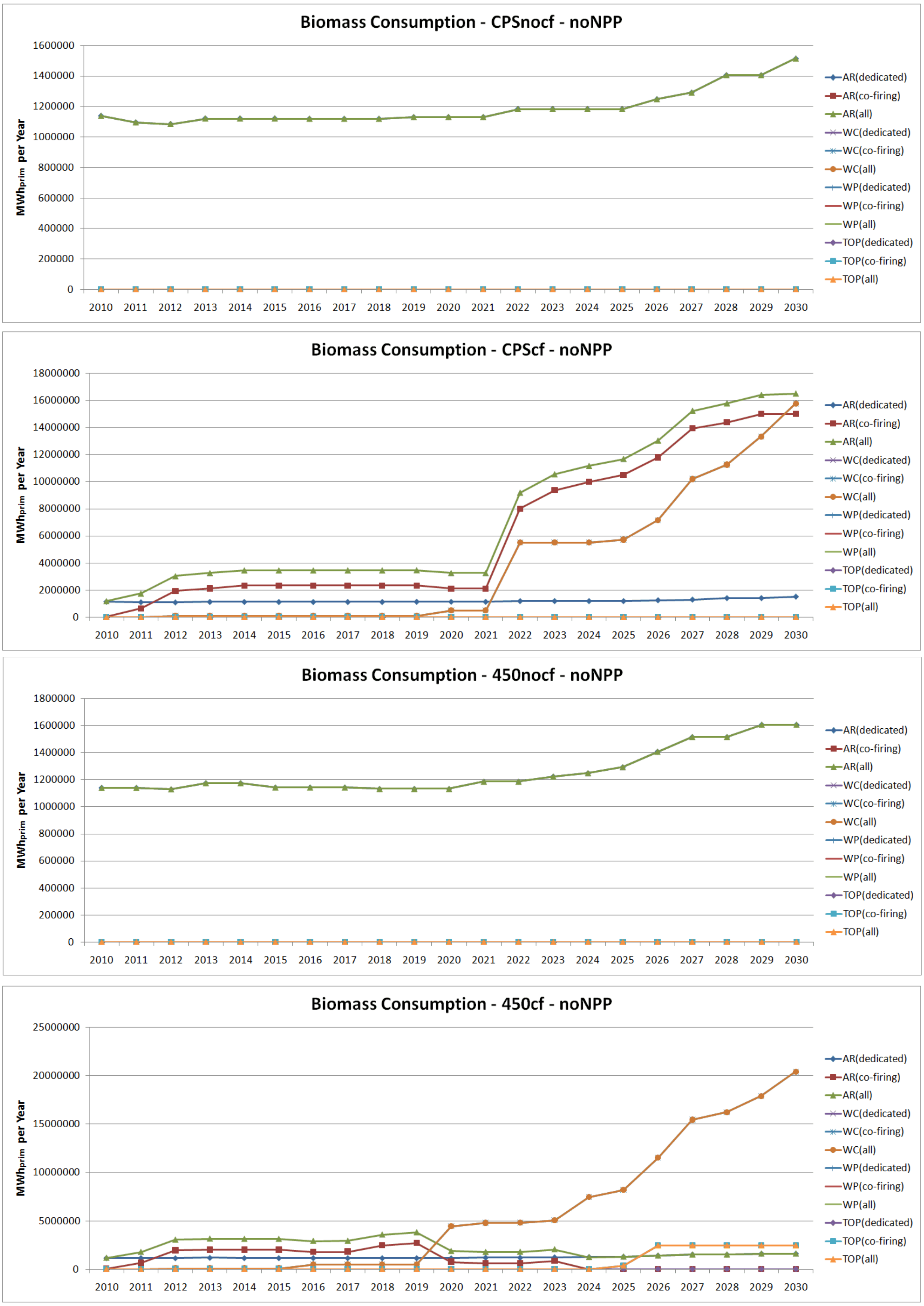
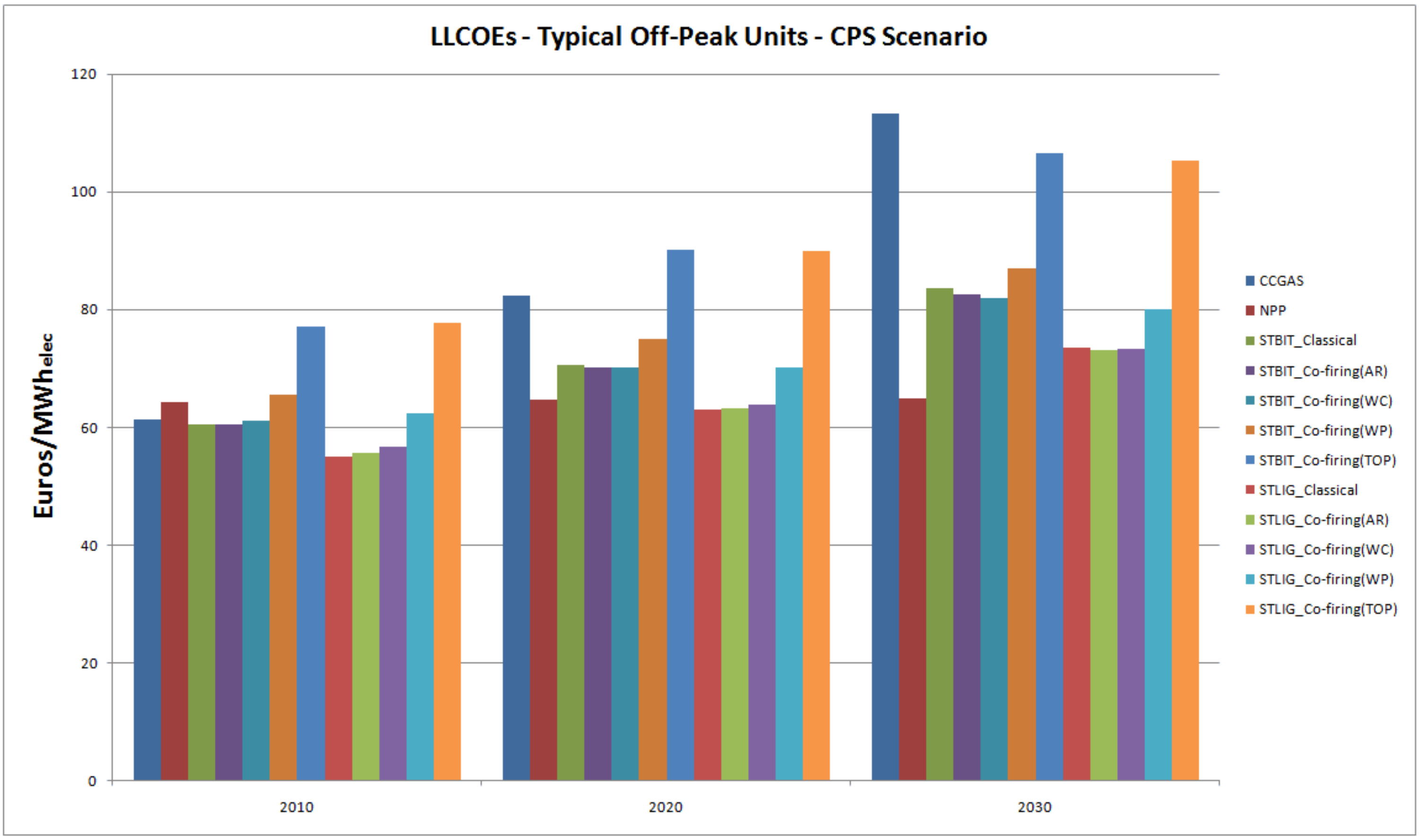


Figure 17: Evolution of biomass consumption in dedicated and coal power plants. Values for the base scenarios in the *cf* and *nocf* model settings, when prolongation of out-of-lifetime nuclear units is not allowed (*noNPP*).



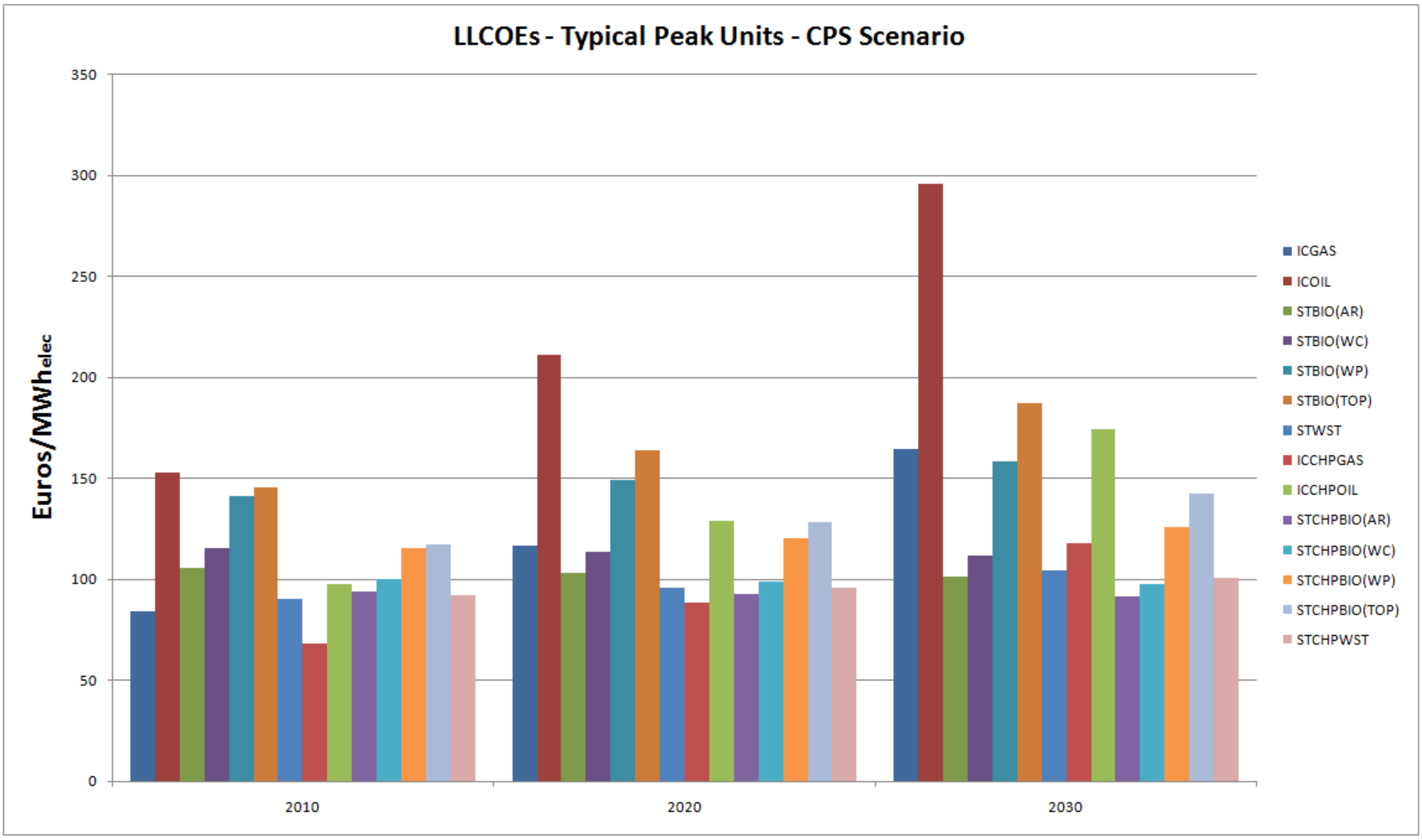
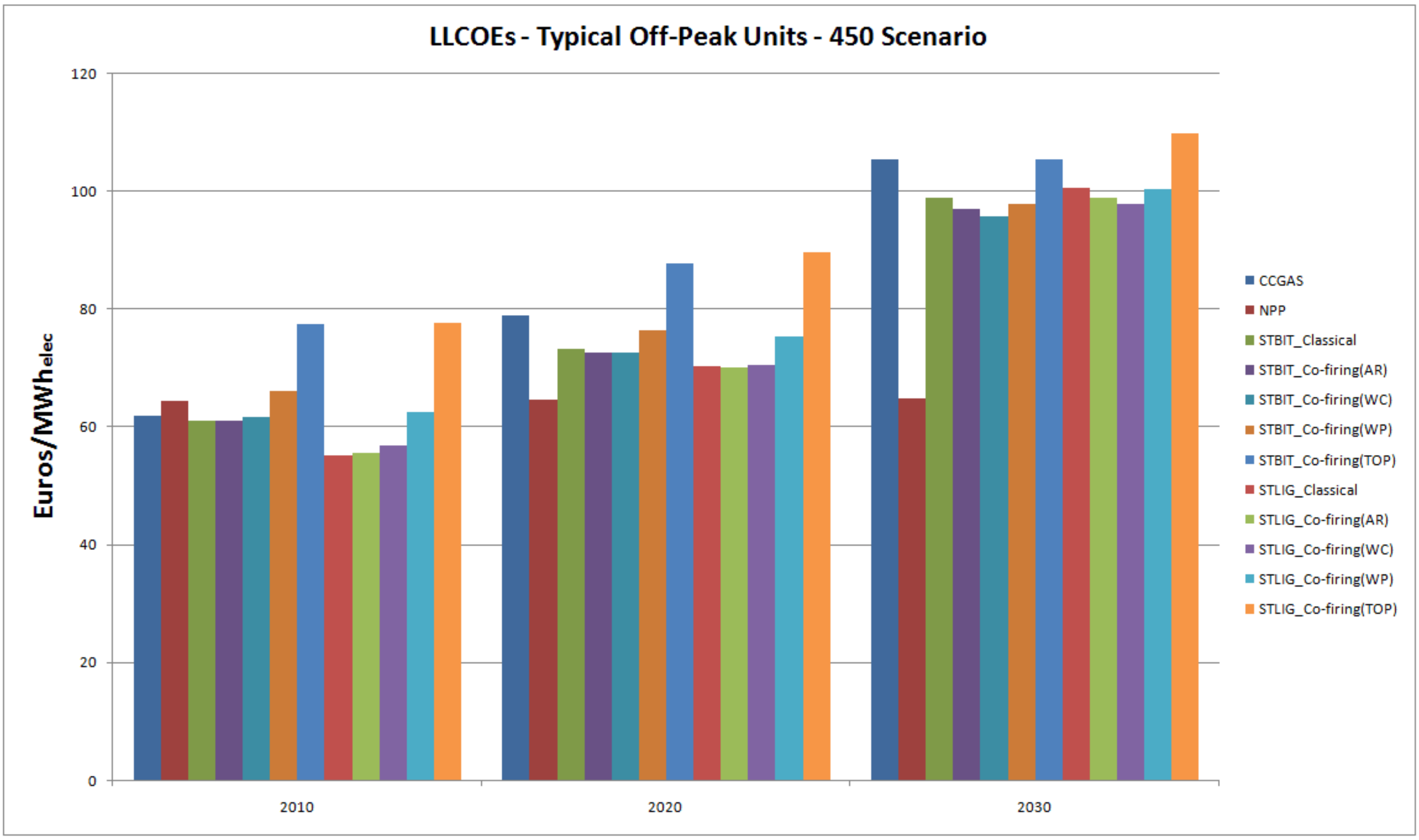


Figure 18: LLCOEs associated with *new* power plants, when considering the prices from the CPS scenario.



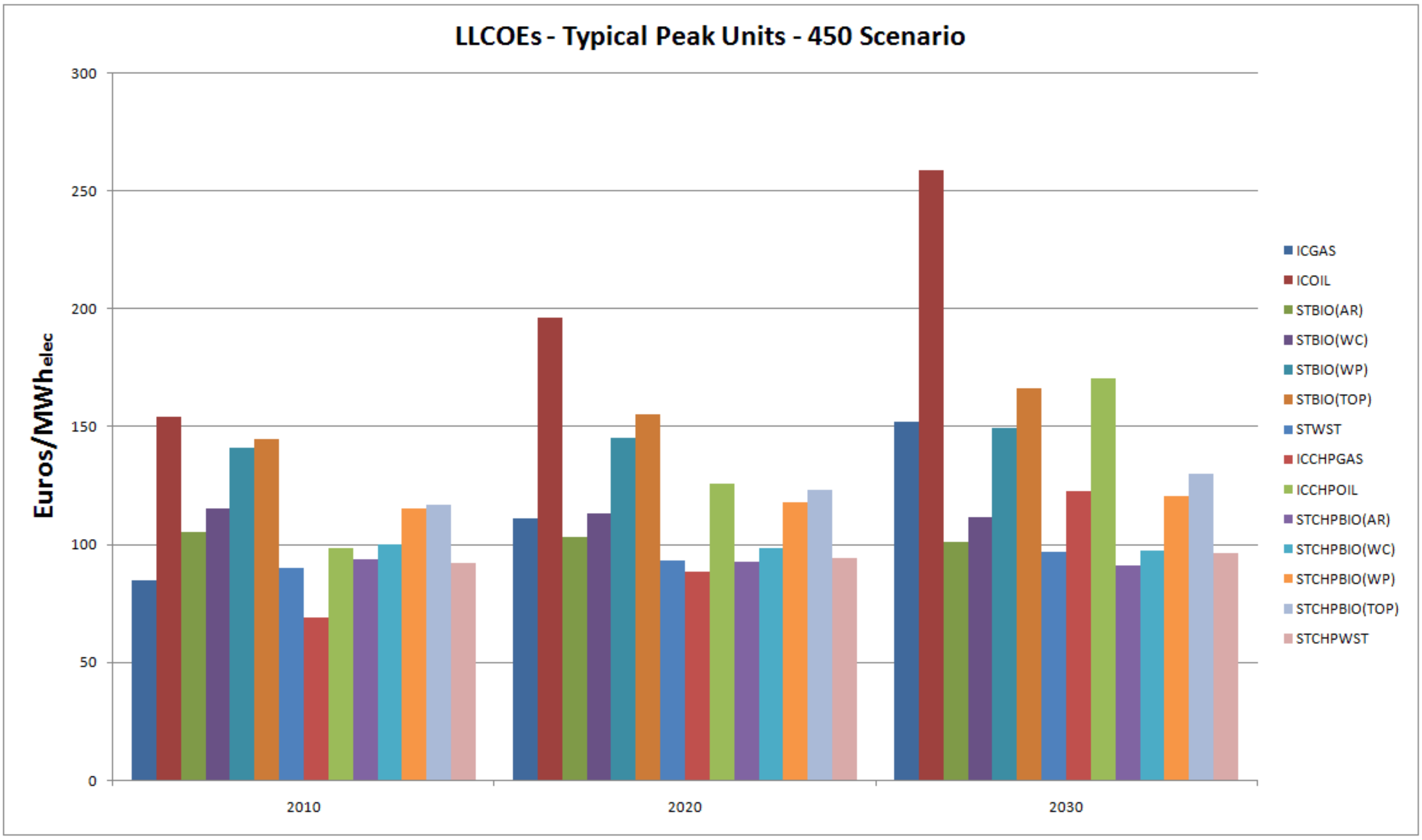


Figure 19: LLCOEs associated with *new* power plants, when considering the prices from the 450 scenario.

A1.2 Policy Analysis

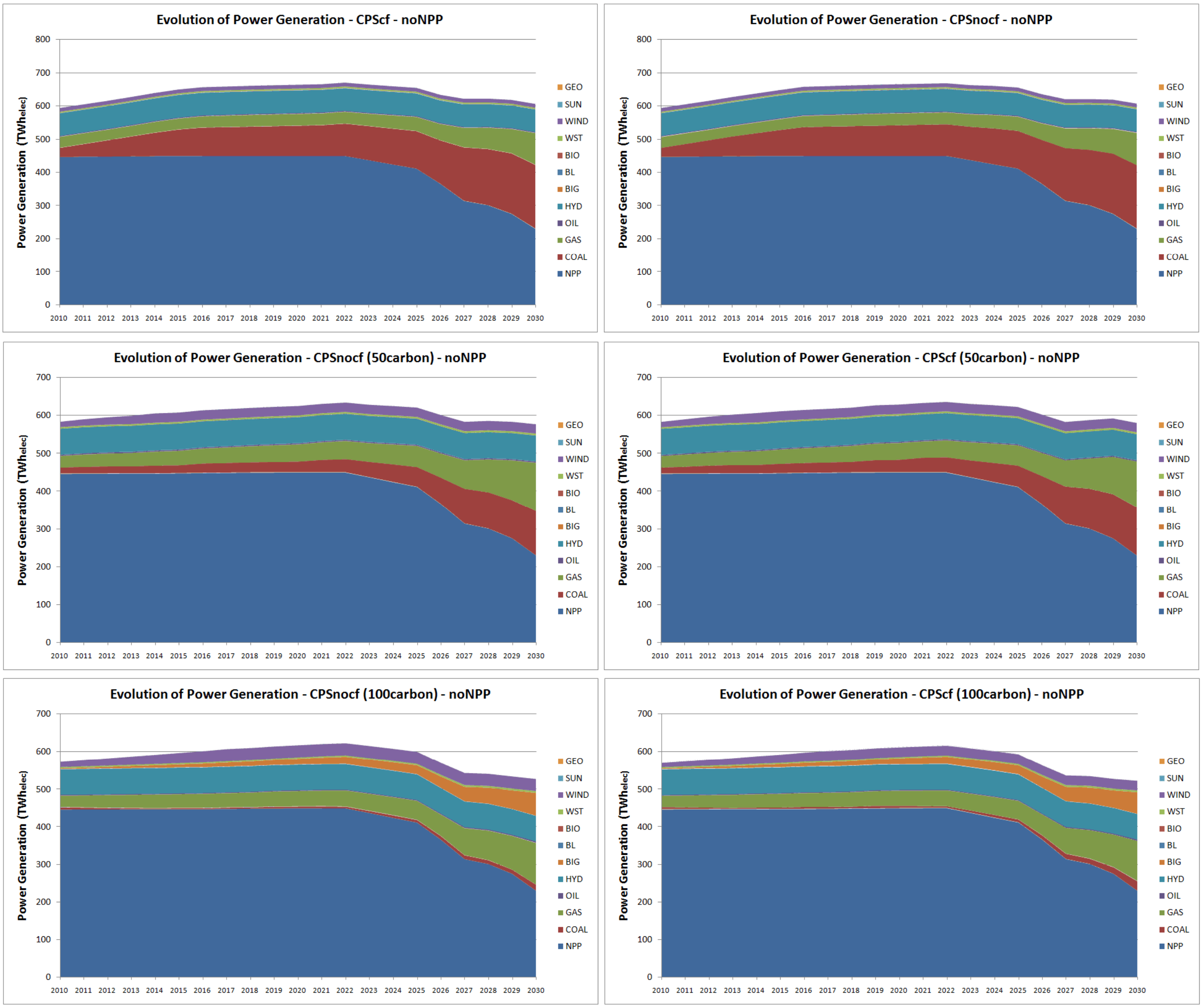


Figure 20: Evolution of the power generation mix in the *noNPP* with *nocf* and *cf* settings with different modified values of the carbon price in the CPS scenario.

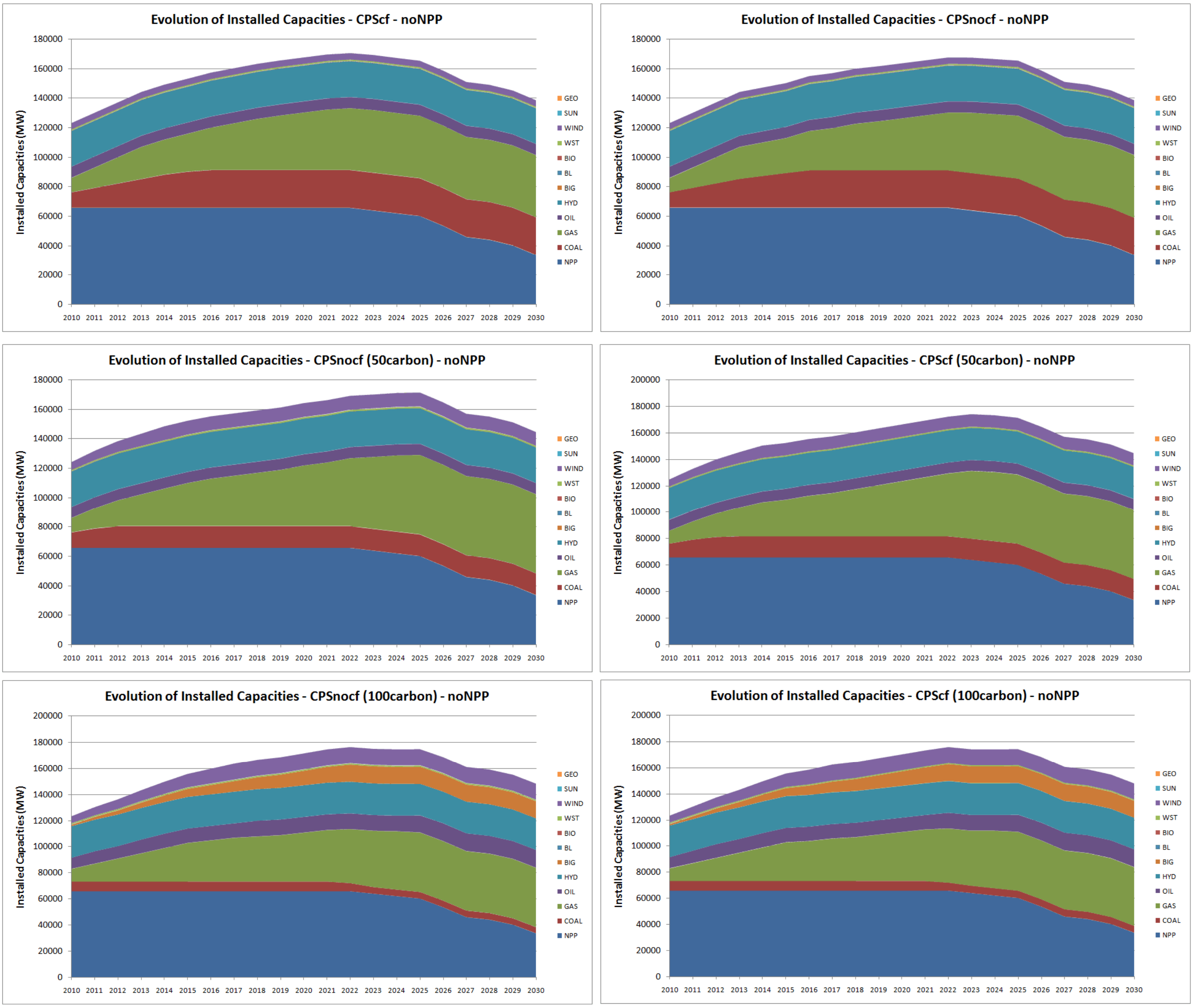
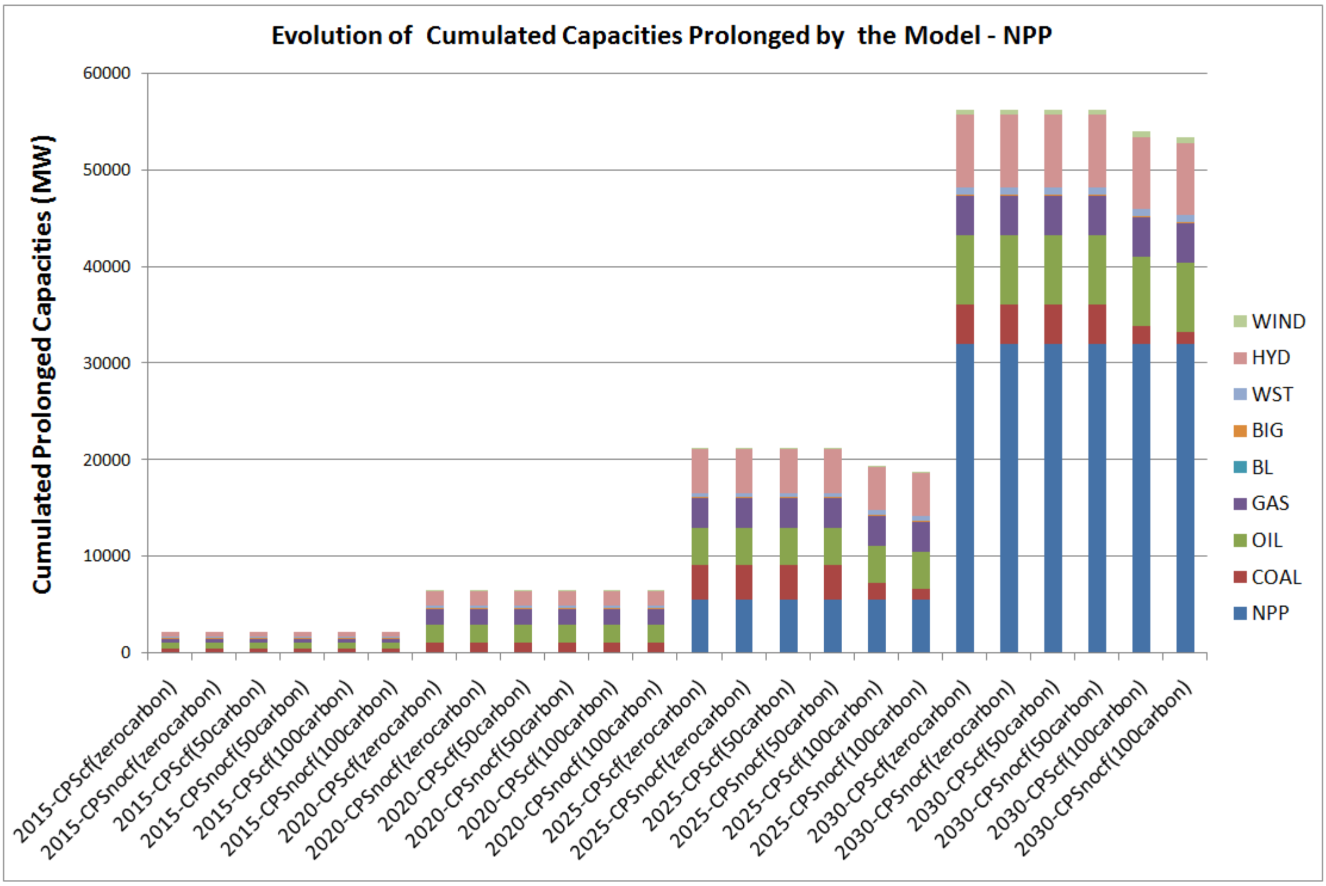


Figure 21: Evolution of the generation capacity mix in the *noNPP* with *nocf* and *cf* settings with different modified values of the carbon price in the CPS scenario.



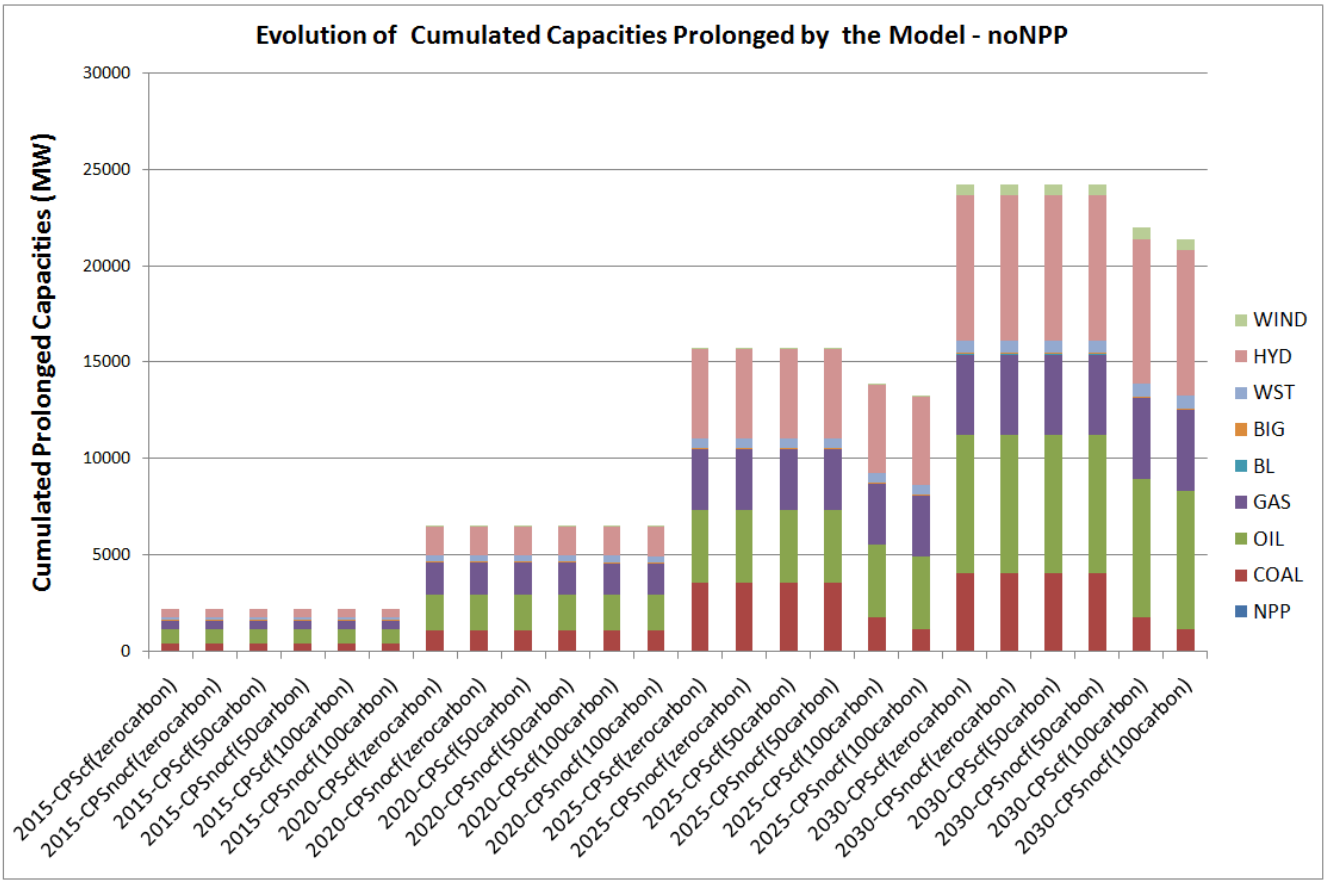


Figure 22: Evolution of cumulated prolonged (*i.e.* the *gp* units, as computed by the model) capacities. Values for 2015, 2020, 2025, and 2030, in the CPS scenario with different modified carbon prices and model settings.

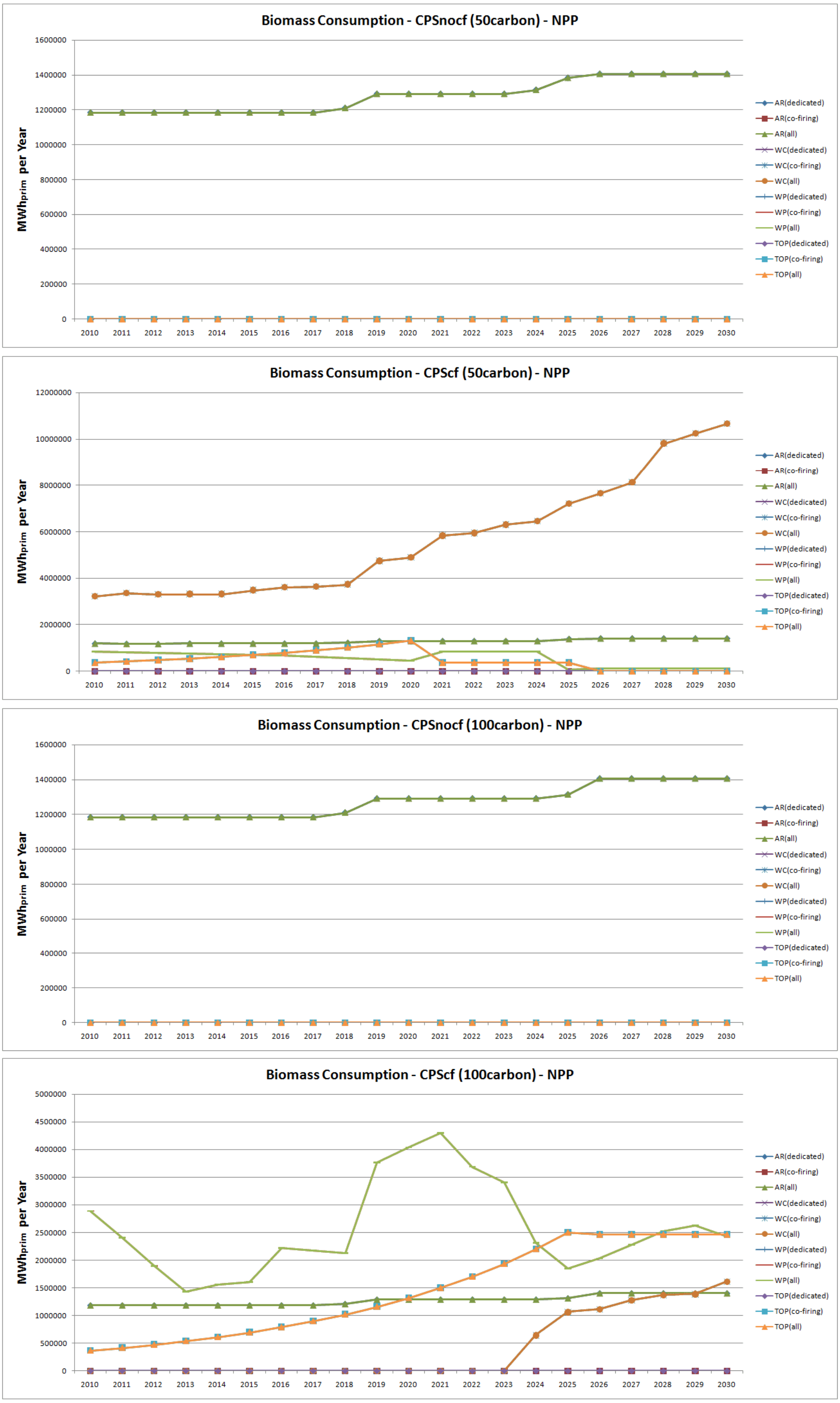


Figure 23: Evolution of biomass consumption in dedicated and coal power plants. Values for different modified carbon prices in the CPS scenario, with the *cf* and *nocf* model settings, when prolongation of out-of-lifetime nuclear units is allowed (*NPP*).

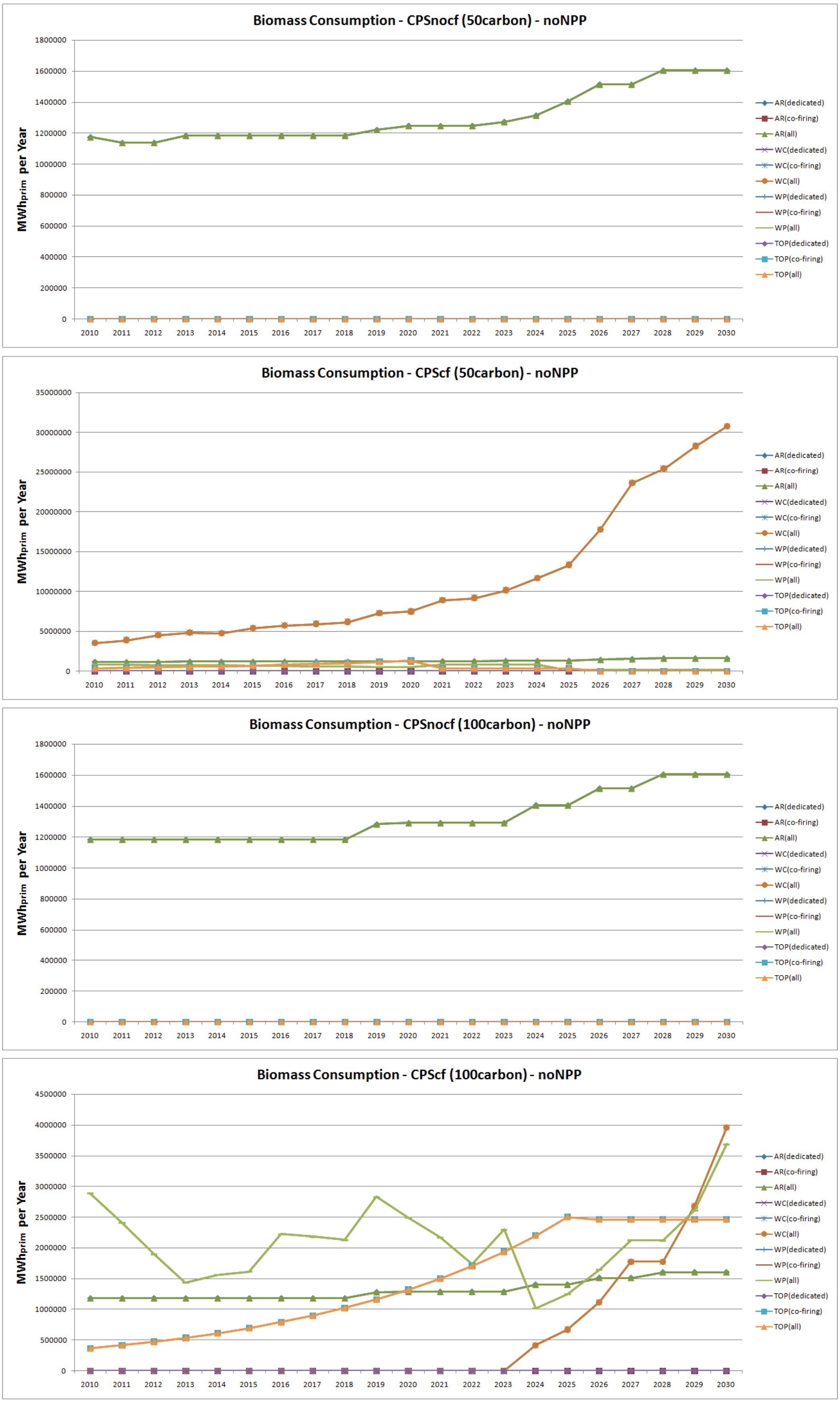
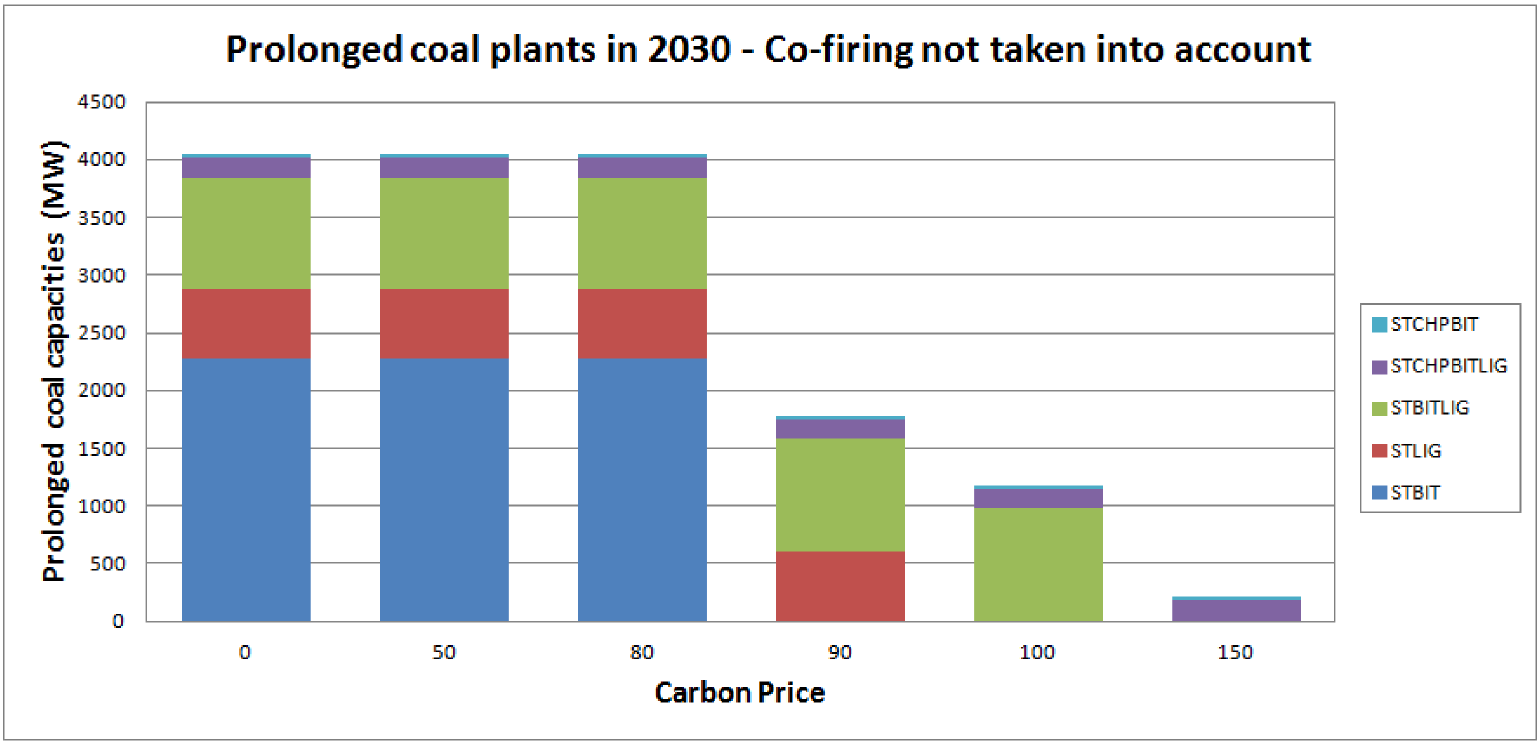


Figure 24 : Evolution of biomass consumption in dedicated and coal power plants. Values for different modified carbon prices in the CPS scenario, with the *cf* and *nocf* model settings, when prolongation of out-of-lifetime nuclear units is not allowed (*noNPP*).



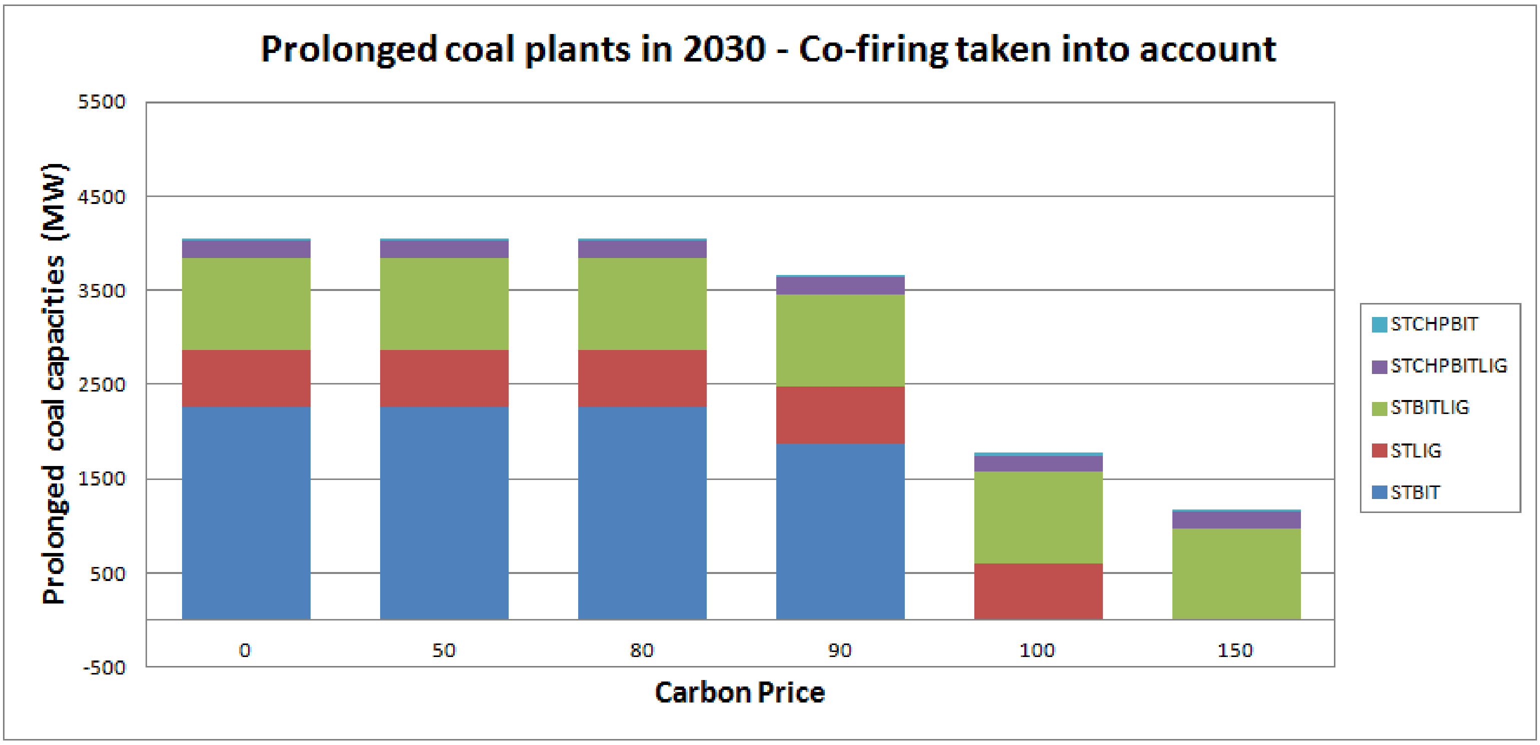


Figure 25: Detailed influence of co-firing (per coal technology) on the cumulated volume of prolonged (*gp*) coal capacities in 2030, when considering different modified values for the carbon price in the CPS scenario.

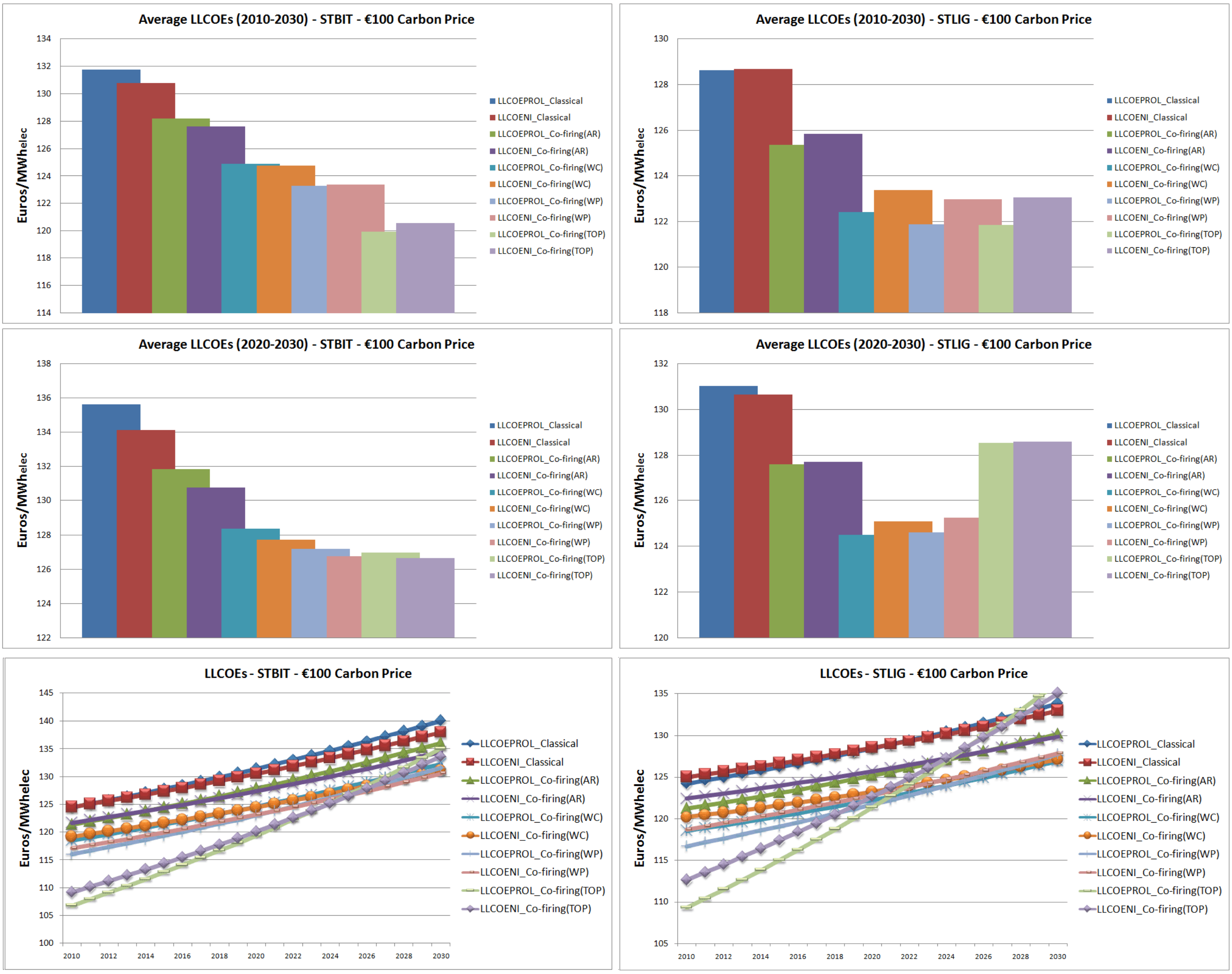


Figure 26: LLCOEs associated with the prolongation/decommissioning decisions (see equation **(5)** and **(6)**) when the carbon price is 100 Euros per tonne of CO_2 (with the fuel prices from the CPS scenario).

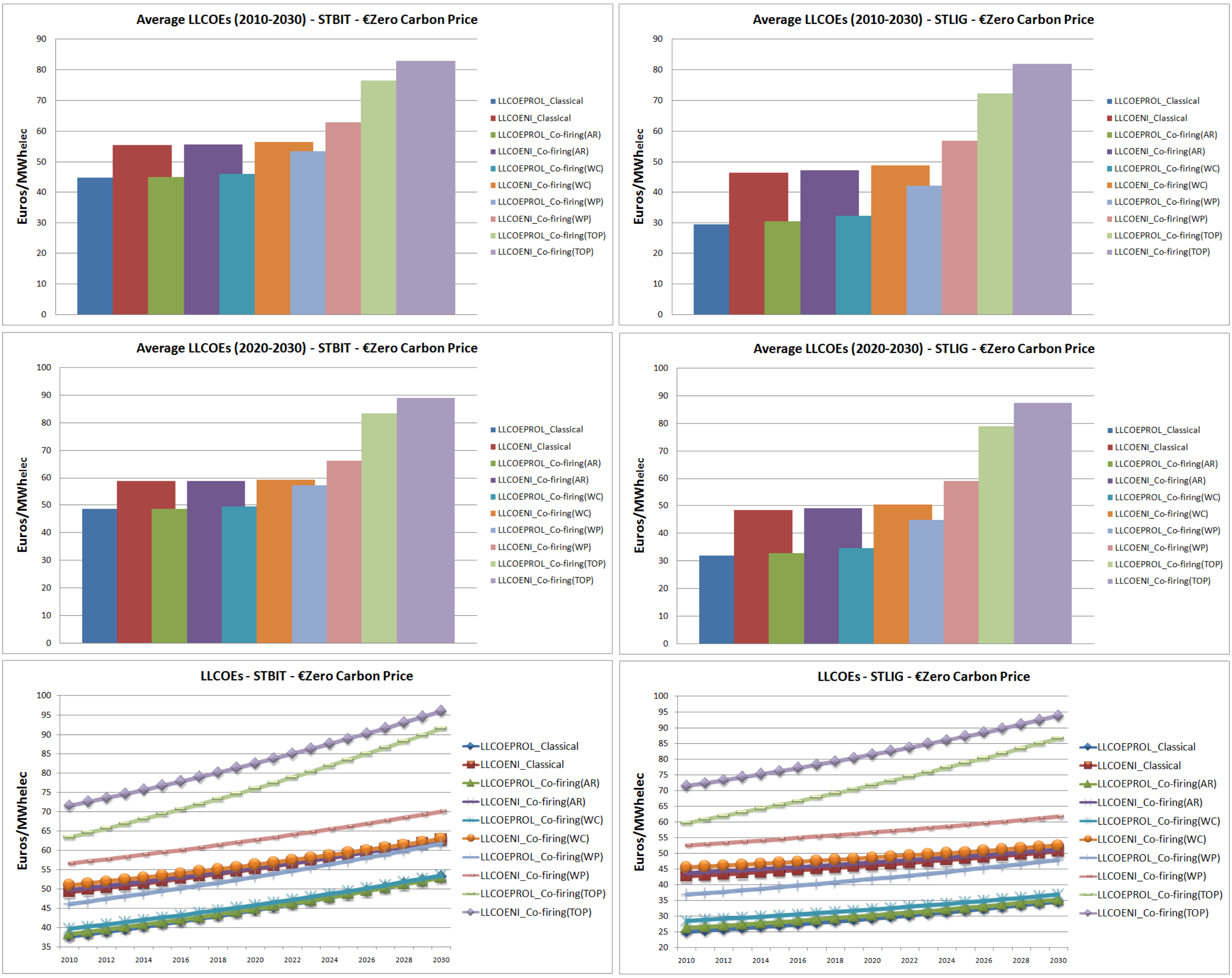


Figure 27 : LLCOEs associated with the prolongation/decommissioning decisions (see equation **(5)** and **(6)**) when there is no carbon price (with the fuel prices from the CPS scenario).

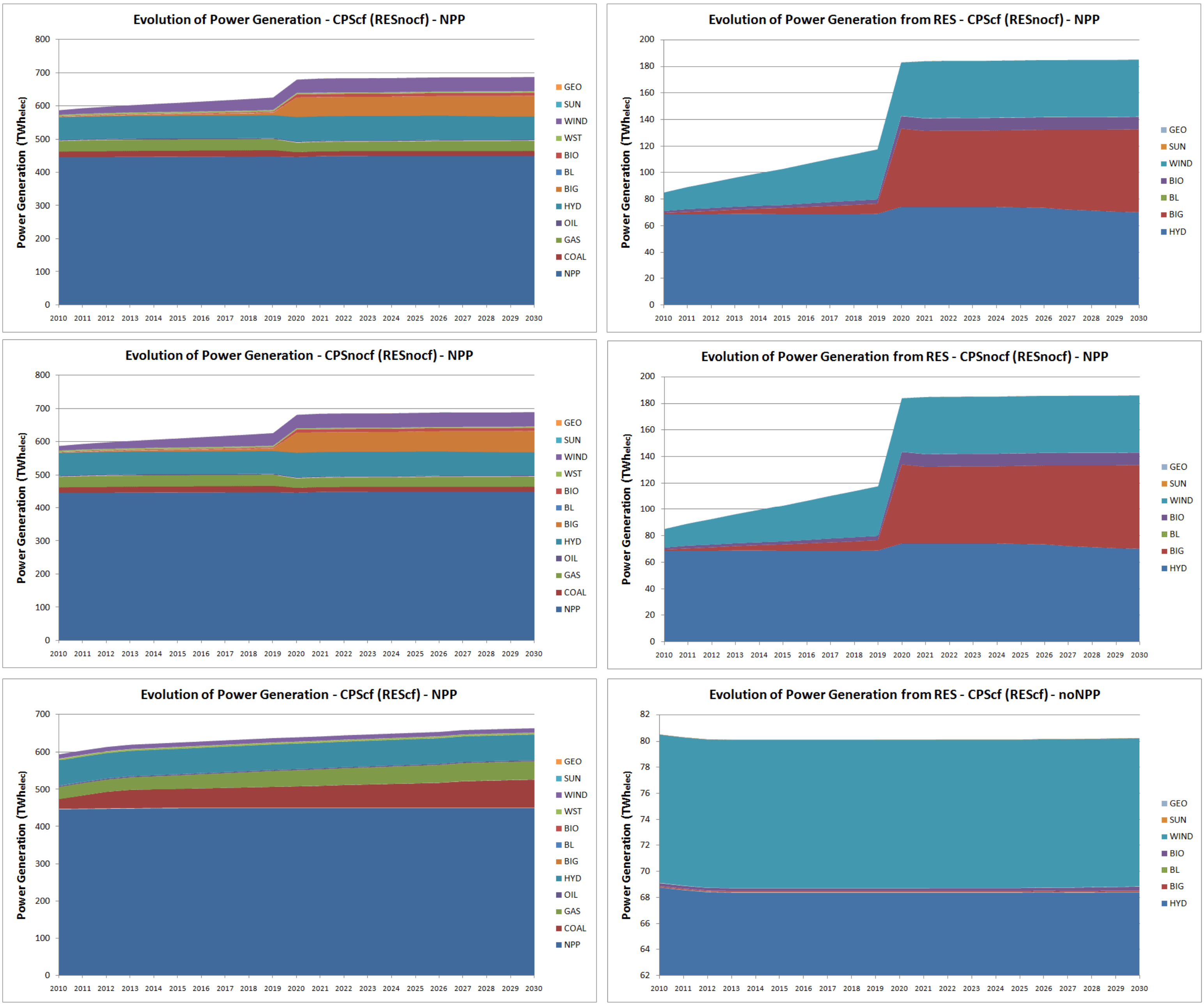


Figure 28: Evolution of the power generation mix in the *NPP* setting, with a constraint on the share of RES in the total power generation in the CPS scenario. *RESnocf* (with *cf* and *nocf* settings) corresponds to the case in which co-firing is not recognized as a RES, whereas it is in the *REScf*.

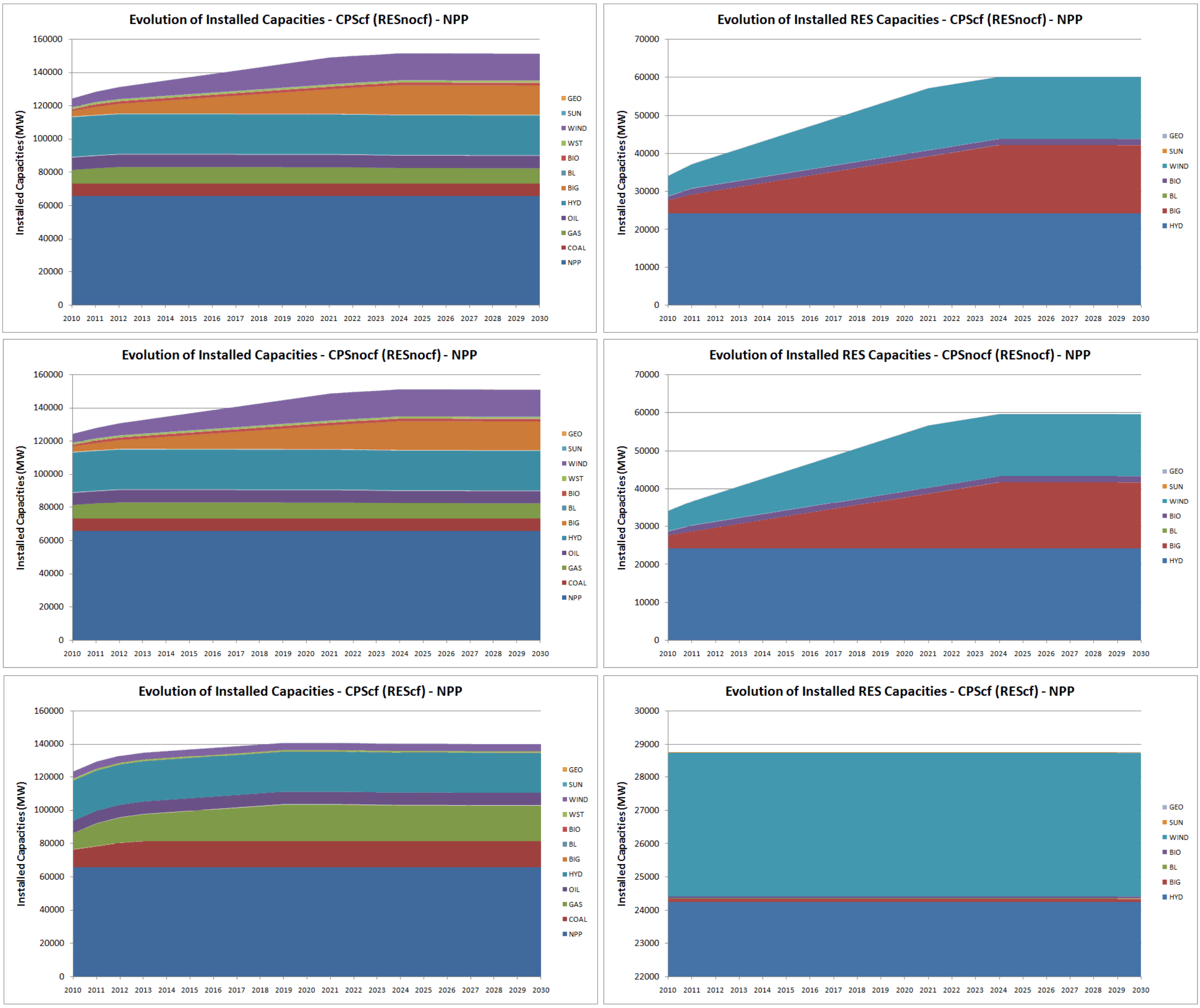


Figure 29: Evolution of the generation capacity mix in the *NPP* setting, with a constraint on the share of RES in the total power generation in the CPS scenario. *RESnocf* (with *cf* and *nocf* settings) corresponds to the case in which co-firing is not recognized as a RES, whereas it is in the *REScf*.

Appendix A2: Power Plants Technologies and Fuels.

Groups of Technologies	Power Plants Technologies	Notation in GES
Nuclear	Nuclear	NPP
	Nuclear CHP	NPPCHP
Bituminous Coal (hard coal)	Steam Turbine Bituminous Coal (hard coal)	STBIT
Lignite Coal	Steam Turbine Lignite Coal	STLIG
Bituminous/Lignite Coal	Steam Turbine Bituminous/Lignite Coal	STBITLIG
Bituminous Coal (hard coal) CHP	Steam Turbine Bituminous Coal (hard coal) CHP	STCHPBIT
Lignite Coal CHP	Steam Turbine Lignite Coal CHP	STCHPLIG
Bituminous/Lignite Coal CHP	Steam Turbine Bituminous/Lignite Coal CHP	STCHPBITLIG
Oil and Bio-liquid (biofuel)	Steam Turbine Oil	STOIL
	Combustion Turbine Oil	CTOIL
	Internal Combustion Oil	ICOIL
	Combustion Turbine Bio-liquid (biofuel)	CTBL
	Internal Combustion Bio-liquid (biofuel)	ICBL
Oil and Bio-liquid (biofuel) CHP	Steam Turbine Oil CHP	STCHPOIL
	Combustion Turbine Oil CHP	CTCHPOIL
	Internal Combustion Oil CHP	ICCHPOIL
	Internal Combustion Bio-liquid (biofuel) CHP	ICCHPBL
Gas and Biogas	Steam Turbine Gas	STGAS
	Steam Turbine Biogas	STBIG
	Combustion Turbine Gas	CTGAS
	Combustion Turbine Biogas	CTBIG
	Internal Combustion Gas	ICGAS
	Internal Combustion Biogas	ICBIG
Gas and Biogas CHP	Steam Turbine Gas CHP	STCHPGAS
	Steam Turbine Biogas CHP	STCHPBIG
	Combustion Turbine Gas CHP	CTCHPGAS
	Combustion Turbine Biogas CHP	CTCHPBIG
	Internal Combustion Gas CHP	ICCHPGAS
	Internal Combustion Biogas CHP	ICCHPBIG
Combined Cycle (CC) Gas turbine	Combined Cycle Oil	CCOIL
	Combined Cycle Gas	CCGAS
	Combined Cycle Biogas	CCBIG
Combined Cycle (CC) Gas turbine CHP	Combined Cycle Gas CHP	CCCHPGAS
Dedicated Biomass	Steam Turbine Biomass	STBIO
	Steam Turbine Waste	STWST
Dedicated Biomass CHP	Steam Turbine Biomass CHP	STCHPBIO
	Steam Turbine Waste CHP	STCHPWST
Hydro conventional (other than pumped and storage)	Hydro conventional (other than pumped and storage)	HYCV
Hydro pumped and storage	Hydro pumped and storage	HYPS
Solar PV	Solar PV	PVP

Wind	Wind Power	WPO
Geothermal	Geothermal	GEO
Geothermal CHP	Geothermal CHP	GEOCHP

Main fuel categories	Fuels included in the categories	Notation in GES	Allowed power plant technologies to burn fuels
Oil	Oil	OIL	STOIL, CTOIL, ICOIL, CCOIL, STCHPOIL, CTCHPOIL, ICCHPOIL
Natural Gas	Natural Gas	GAS	STGAS, CTGAS, ICGAS, CCGAS, STCHPGAS, CTCHPGAS, ICCHPGAS, CCCHPGAS
Coal	Bituminous coal (hard-coal)	BIT	STBIT, STBITLIG, STCHPBIT, STCHPBITLIG
	Lignite	LIG	STLIG, STBITLIG, STCHPLIG, STCHPBITLIG
Uranium	Uranium	OU	NPP, NPPCHP
Solid Biomass	Torrefied Pellets	TOP	STBIO, STCHPBIO, STBIT (co-firing), STLIG (co-firing), STBITLIG (co-firing), STCHPBIT (co-firing), STCHPLIG (co-firing), STCHPBITLIG (co-firing)
	Wood Pellets	WP	STBIO, STCHPBIO, STBIT (co-firing), STLIG (co-firing), STBITLIG (co-firing), STCHPBIT (co-firing), STCHPLIG (co-firing), STCHPBITLIG (co-firing)
	Wood Chips	WC	STBIO, STCHPBIO, STBIT (co-firing), STLIG (co-firing), STBITLIG (co-firing), STCHPBIT (co-firing), STCHPLIG (co-firing), STCHPBITLIG (co-firing)
	Agricultural Residues	AR	STBIO, STCHPBIO, STBIT (co-firing), STLIG (co-firing), STBITLIG (co-firing), STCHPBIT (co-firing), STCHPLIG (co-firing), STCHPBITLIG (co-firing)
Waste	Mixed Grade Waste	MGW	STWST, STCHPWST
Biogas	Biogas	BIG	STBIG, CTBIG, ICBIG, CCBIG, STCHPBIG, CTCHPBIG, ICCHPBIG
Bio-Liquid	Bio-Liquid	BL	CTBL, ICBL, CTCHPBL, ICCHPBL

Appendix A3: Summary of the main notations.

Sets and Indices

Main Sets			Sub-Sets	
Notation	**Description**	**Index**	**Notation**	**Description**
U	Power plant technologies.	u	UNC	All the power plants, except the coal plants (*no-coal power plants*).
			UC	All the coal plants.
P	Prolongation status for power plants [p_0,…,p_n], where p_n stands for power plants that have been prolonged n times before 2010.	p	-	-
F	Fuels for power plants.	f	FC	All the coal-based fuels.
			FNC	All the fuels, except the coal-based fuels.
			FSB	Solid biomass fuels.
MF	Main fuels for coal plants under co-firing configuration. $MF \subset FC$.	m	-	-
BAQ	Biomass alternate fuels for coal plants under co-firing configurations. $BAQ \subset FSB$.	b	-	-
T	Years in the considered time interval [2010,…,2030].	t	-	-
V	Initial vintages of power plants (year of commissioning or of last refurbishment).	v	-	-
PPC	Power plant categorization. We distinguish here between old units that have not been prolonged by the model (*old*),[b] out-of-lifetime units that have been prolonged by the model (*gp=GES prolongation*), and new units that come from investments (*new*).	-	-	-
VGP	Vintage of *gp* power plants (*i.e.* old plants, prolonged by the model as of 2010).	vgp	-	-
VNI	Vintage of *new* power plants (*i.e.* commissioned new investments as of 2010).	vni	-	-

Variable

Notation	**Description**
$C^{old}_{t,u,v,p}$	Installed capacity (MW) in year t for *old* power plants u of vintage v (with v < 2010), which have been prolonged p times before 2010.

$C^{gp}_{u,v,p,vgp}$	Installed capacity (MW) for *gp* power plants u (*i.e.* old plants, prolonged by the model as of 2010) of vintage *vgp* (with $vgp \geq 2010$), which have been prolonged p times since v (with $v < 2010$) and before 2010.[a]
$C^{old,decom}_{t,u,v,p}$	Decommissioned capacity (MW) in year t for *old* power plants u (*i.e.* old plants, decommissioned by the model as of 2010) of vintage v (with $v < 2010$), which have been prolonged p times before 2010.
$C^{new}_{u,vni}$	Installed capacity (MW) for *new* power plants u (*i.e.* commissioned new investments) of vintage *vni* (with $vni \geq 2010$).
$\left(LLCOENI^{t_0}_{t,u,f}\right)_{u \in UNC}$	LLCOE (2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering new investments in year t for no-coal power plants u using fuel f.
$\left(LLCOENI^{t_0,nocf}_{t,u,f}\right)_{u \in UC}$	LLCOE (2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering new investments in year t for coal power plants u using fuel f in classical configuration.
$\left(LLCOENI^{t_0,cf}_{t,u,m,b}\right)_{u \in UC}$	LLCOE (2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering new investments in year t for coal power plants u in co-firing configuration with main fuel m and alternate biomass fuel b.
$\left(LLCOEPROL^{t_0}_{t,u,f}\right)_{u \in UNC}$	LLCOE (2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering to prolong in year t out-of-lifetime no-coal power plants u using fuel f.
$\left(LLCOEPROL^{t_0,nocf}_{t,u,f}\right)_{u \in UC}$	LLCOE (2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering to prolong in year t out-of-lifetime coal power plants u using fuel f in classical configuration.
$\left(LLCOEPROL^{t_0,cf}_{t,u,m,b}\right)_{u \in UC}$	LLCOE(2010EUR/MWh$_{elec}$, with t_0 as reference year for discounting) when considering to prolong in year t out-of-lifetime coal power plants u in co-firing configuration with main fuel m and alternate biomass fuel b.

Parameters

Notation	Description
lf_u	Load-factor of power plants u.
$lifetime_u$	Lifetime of power plants u that have not been prolonged: $C^{new}_{u,vni}$ or $\left(C^{old}_{t,u,v,p}\right)_{p \in P \setminus \{p_1,\ldots,p_n\}}$ with $n > 0$.
$lifetimeprol_u$	Lifetime of power plants u that have been prolonged: $C^{gp}_{u,v,p,vgp}$ or $\left(C^{old}_{t,u,v,p}\right)_{p \in P \setminus p_0}$.

[a]: The v in this case refers to the same year as for *old* power plants.

[b]: Note that among the *old* units, some may have been already prolonged before 2010 (*i.e.* the ones associated with a p_n so that $n > 0$), but the prolongation in this case is not implemented by the model.

Appendix A4: Summary of the IEA (2012) scenarios.

	Current Policy Scenario (CPS)	New Policy Scenario (NPS)	450 Scenario (450)
Definitions	Government policies that had been enacted or adopted by mid-2012 continue unchanged.	Existing policies are maintained and recently announced commitments and plans, including those yet to be formally adopted, are implemented in a cautious manner.	Policies are adopted that put the world on a pathway that is consistent with having around a 50% chance of limiting the global increase in average temperature to 2°C in the long term, compared with pre-industrial levels.

Source: Chapter 1 of IEA (2012).

Appendix A5: Illustrations of merit-order with co-firing.

Table 11: Merit-orders for a sample of technologies with different carbon price conditions (marginal costs are given in brackets). Values are given for two representative years 2015 and 2025. In each case, the best co-firing configuration of bituminous (lignite, *respectively*) coal plants appears in green (brown, *respectively*).

2015 – CPS – Zero Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STLIG - Classical (18.31)	STLIG - Co-firing AR (19.49)	STBIT - Classical (30.88)	STBIT - Co-firing AR (31.35)	CCGAS (48.74)	STBIO - WC (70.68)	CTGAS (83.76)	STWST (122.24)	CTOIL (146.17)
2015 – CPS – Unmodified CPS Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STLIG - Classical (35.67)	STLIG - Co-firing AR (36.10)	STBIT - Co-firing AR (45.90)	STBIT - Classical (46.10)	CCGAS (55.23)	STBIO - WC (70.68)	CTGAS (94.93)	STWST (122.24)	CTOIL (159.58)
2015 – CPS – Fixed 50 Euros Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STLIG - Co-firing WC (66.56)	CCGAS (67.28)	STLIG - Classical (67.89)	STBIO - WC (70.68)	STBIT - Co-firing WC (71.99)	STBIT - Classical (74.34)	CTGAS (115.64)	STWST (122.24)	CTOIL (184.45)
2015 – CPS – Fixed 100 Euros Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STBIO - WC (70.68)	CCGAS (85.83)	STBIT - Co-firing TOP (102.78)	STLIG - Co-firing TOP (106.27)	STLIG - Classical (117.47)	STBIT - Classical (117.80)	STWST (122.24)	CTGAS (147.51)	CTOIL (222.74)
2025 – CPS – Zero Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.51)	STLIG - Classical (23.08)	STLIG - Co-firing AR (23.93)	STBIT - Classical (38.61)	STBIT - Co-firing AR (38.65)	STBIO - WC (68.12)	CCGAS (72.84)	CTGAS (125.19)	STWST (150.56)	CTOIL (211.65)
2025 – CPS – Unmodified CPS Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.51)	STLIG - Co-firing AR (46.60)	STLIG - Classical (46.75)	STBIT - Co-firing WC (58.24)	STBIT - Classical (59.36)	STBIO - WC (68.12)	CCGAS (81.69)	CTGAS (140.41)	STWST (150.56)	CTOIL (229.92)
2025 – CPS – Fixed 50 Euros Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.51)	STBIO - WC (68.12)	STLIG - Co-firing WC (72.66)	STLIG - Classical (46.75)	STBIT - Co-firing WC (78.84)	STBIT - Classical (82.07)	CCGAS (91.38)	STWST (150.56)	CTGAS (157.07)	CTOIL (249.93)
2025 – CPS – Fixed 100 Euros Carbon Price													
Merit-Order	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.51)	STBIO - WC (68.12)	CCGAS (109.93)	STLIG - Co-firing WC (115.72)	STBIT - Co-firing TOP (116.81)	STLIG - Classical (122.25)	STBIT - Classical (125.53)	STWST (150.56)	CTGAS (188.94)	CTOIL (288.22)

Table 12: Merit-orders for a sample of technologies between 2015 and 2020 (marginal costs are given in brackets). Values are given with two carbon price conditions: fixed 50 Euros and unmodified CPS carbon prices. In each case, the best co-firing configuration of bituminous (lignite, *respectively*) coal plants appears in green (brown, *respectively*).

Merit-Order	***CPS – Unmodified CPS Carbon Price***												
2015	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STLIG - Classical (35.67)	STLIG - Co-firing AR (36.10)	STBIT - Co-firing AR (45.90)	STBIT - Classical (46.10)	CCGAS (55.23)	STBIO - WC (70.68)	CTGAS (94.93)	STWST (122.24)	CTOIL (159.58)
2016	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.28)	STLIG - Classical (36.65)	STLIG - Co-firing AR (37.03)	STBIT - Co-firing AR (47.02)	STBIT - Classical (47.28)	CCGAS (57.43)	STBIO - WC (70.42)	CTGAS (98.71)	STWST (124.81)	CTOIL (165.51)
2017	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.30)	STLIG - Classical (37.65)	STLIG - Co-firing AR (37.98)	STBIT - Co-firing AR (48.13)	STBIT - Classical (48.48)	CCGAS (59.72)	STBIO - WC (70.16)	CTGAS (102.65)	STWST (127.44)	CTOIL (171.67)
2018	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.33)	STLIG - Classical (38.68)	STLIG - Co-firing AR (38.95)	STBIT - Co-firing AR (49.34)	STBIT - Classical (49.72)	CCGAS (62.11)	STBIO - WC (69.90)	CTGAS (106.75)	STWST (130.13)	CTOIL (178.05)
2019	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.35)	STLIG - Classical (39.73)	STLIG - Co-firing AR (39.93)	STBIT - Co-firing AR (50.55)	STBIT - Classical (50.99)	CCGAS (64.59)	STBIO - WC (69.64)	CTGAS (111.01)	STWST (132.87)	CTOIL (184.67)
2020	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.38)	STLIG - Classical (40.83)	STLIG - Co-firing AR (40.99)	STBIT - Co-firing AR (51.78)	STBIT - Classical (52.30)	CCGAS (67.16)	STBIO - WC (69.39)	CTGAS (115.44)	STWST (135.66)	CTOIL (191.54)
Merit-Order	***CPS – Fixed 50 Euros Carbon Price***												
2015	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.25)	STLIG - Co-firing WC (66.56)	CCGAS (67.28)	STLIG - Classical (67.89)	STBIO - WC (70.68)	STBIT - Co-firing WC (71.99)	STBIT - Classical (74.34)	CTGAS (115.64)	STWST (122.24)	CTOIL (184.45)
2016	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.28)	STLIG - Co-firing WC (66.93)	STLIG - Classical (68.32)	CCGAS (69.28)	STBIO - WC (70.42)	STBIT - Co-firing WC (72.60)	STBIT - Classical (75.04)	CTGAS (119.07)	STWST (124.81)	CTOIL (189.96)
2017	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.30)	STLIG - Co-firing WC (67.31)	STLIG - Classical (68.76)	STBIO - WC (70.16)	CCGAS (71.36)	STBIT - Co-firing WC (73.24)	STBIT - Classical (75.75)	CTGAS (122.65)	STWST (127.44)	CTOIL (195.68)
2018	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.33)	STLIG - Co-firing WC (67.70)	STLIG - Classical (69.21)	STBIO - WC (69.90)	CCGAS (73.52)	STBIT - Co-firing WC (73.88)	STBIT - Classical (76.48)	STWST (126.37)	CTGAS (130.13)	CTOIL (201.62)
2019	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.35)	STLIG - Co-firing WC (68.10)	STBIO - WC (69.64)	STLIG - Classical (69.67)	STBIT - Co-firing WC (74.54)	CCGAS (75.78)	STBIT - Classical (77.23)	CTGAS (130.25)	STWST (132.87)	CTOIL (207.78)
2020	HYCV (0.00)	PVP (0.00)	WPO (0.00)	NPP (5.38)	STLIG - Co-firing WC (68.51)	STBIO - WC (69.39)	STLIG - Classical (70.14)	STBIT - Co-firing WC (75.22)	STBIT - Classical (77.99)	CCGAS (78.13)	CTGAS (134.28)	STWST (135.66)	CTOIL (214.17)

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