An exercise of comparison of the impact of environmental policies on electricity generation in France: feed-in tariffs vs. the EU ETS*

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Abstract

This paper is an exercise of comparison of the impact of environmental policies on electricity generation in France: feed-in tariffs vs. the EU ETS. Comparison is based on investment and CO2 emission reduction induced, as well as improvement in competition, with in parallel policy cost beard to the society. This exercise is run by considering two types of producers, the incumbent and the smaller producers aggregated (the entrant) who supply two types of consumers:

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consumers depending on temperatures, such as residential, commercial, public consumers and the other ones. Our results show that the two policies contribute to reduce CO2 emissions. The retained feed-in tariff policy seems more expensive for the "social welfare" and less effective in terms of emissions reduction. In that we are in line with theoretical literature on feed in tariffs and quotas obligation system.

1 Introduction: binding targets to greenhouse gas emissions and to renewable energy share

Electricity production is responsible for 20% of total greenhouse gases (GHG) emissions in the world. Among GHG, CO2 is the most common and is mostly emitted through combustion of fossil fuel, industrial processes and deforestation. Political support to renewable energy technologies has a history of over 30 years within the European Union (EU). The last framework is given by the 1997 Kyoto protocol which sets legally binding targets for industrialized countries, to stabilize CO2 concentration in the atmosphere. The EU-15 Member States are committed to reduce their GHG emissions by 8% compared to 1990 levels. In April 2002, the EU agreed on different targets by country depending on economic circumstances and on accomplished progress since 1990. Since the 17th of March 2007, the EU-25 Member States confirmed the 17 propositions of the EU's package "Energy - Climate Change" proposed on January 10th in order to strengthen the European policy on climate change. They have to reduce GHG emissions by 20% before 2020, or even by 30% in case of an international agreement. They decided on a binding target of 20% of renewable energies in the European primary energy mix. In parallel an objective on energy efficiency is added: a 20 % saving on primary energy consumption before 2020. National objectives remain to be defined, which will take into account the countries' current and potential energy mixes.

Renewable energies are not mature generation technologies because they are not yet technologically and / or economically efficient. These technologies are often intermittent energies sources. Thus they generate additional costs due to the additional plants necessary to supply peak demand and to equilibrate networks. Policy measures to promote renewable energies are seen as solutions to reach environmental objectives, secure supply, and also an alternative way to enhance competition on the EU power market. They are market-based instruments which can be distinguished between direct subsidies (or taxes which can be considered as indirect subsidies) and tradable quotas. The European Commission survey (2005) established that the two common promotion measures were feed-in tariffs (in seven out of the EU-15 Member States including France, which offer the advantage to allow for differentiation between renewable technologies) and quota obligation systems with tradable green certificates. The European Union Greenhouse Gas Emission Trading Scheme (EU ETS), superseding the latter, is now implemented in all EU countries. In January 2005 the EU ETS begun to operate as the largest multi-country, multi-sector GHG emission trading scheme world-wide, based on Directive 2003/87/EC. Since the beginning the scope of the EU ETS includes the electricity sector. In order to cap GHG emissions, the EU ETS is the marketplace for CO2 emission quotas. But as shown by Reinaud (2003), the electricity price does not totally include the CO2 emission price, because of the market strategies of generators who are not in pure and perfect competition (market price does not equal marginal cost), and who are constrained by regulation. So the start of power plants, which is formerly defined by the economical "merit order" (according the increased long-term marginal costs), does not only follow the environmental "merit order", which can modify the places of coal-fired and gas-fired plants according to the assumed fuel and CO2 prices.

We choose a numerical model[1] which focuses on sequencing a one-stage decision and multi-period actions in order to model investments in generation capacities under deregulated environment. In the absence of competition and considering an annual load-duration curve, power is generated according to a chosen capacity mix, to meet demand at a minimal cost. Chaton (1998) determines optimal investment in thermal power plants in a two-period model. This model accounts explicitly for the nature of the electric demand through the load-duration curve and considers emission constraints. The extension proposed by Chaton and Doucet (2003) adds an additional period to her model and explicitly takes into account electricity trading. For Madlener, Kumboglu and Ediger (2005), firms adopt a profit maximizing behavior on the competitive market. Their paper introduces the interest for environmental sustainability by adding emission reductions into the model. Kumboglu, Madlener and Demirel (2007) extend this model by considering learning curves for renewable energy technologies. Additionally, Pineau and Murto (2005) focus on investment decisions and competition in the long run. They question the competitive nature of European markets and compare competition and oligopoly maximizing profits. They also assume that supply is constrained by limited technologies (nuclear and hydropower), due to social-political considerations and the restricted availability of sites. It responds to a demand which is split between base and peak load periods for 80% vs. 20% of time. At last, Genc and Sen (2007) add a specification as competition takes place in wholesale markets where large user customers (e.g. industrials) pay market prices, while end-user customers pay fixed regulated prices.

This modelling describes competition on European electricity markets. It allows us to introduce the two environmental policies we focus on, feed-in tar-

[1] In this paper, we don't consider the uncertainty that numerical models can introduce on demand or price.

iffs and the EU ETS, and to compare them in terms of deployment, prices and profits. Comparisons on renewable energy promotion policies often conclude that feed-in tariffs incur substantial excess cost in terms of public subsidies compared to an EU-wide tradable green quota (cf. Menanteau, Finon and Lamy, 2003, Böhringer, Hoffman, Rutherford, 2006). This excess cost can be interpreted as the price tag that policy makers have to attach to reach other objectives[2] than attaining the determined part of renewable energy in the generation mix. Although in theory the United-Kingdom scheme (quota and auction mechanisms) should be a lower cost mechanism than the German one (feed-in tariff), in practise this is not the case as Butler and Neuhoff (2007) confirmed by focusing on one technology, onshore wind energy. The resource-adjusted cost to society of the feed-in tariff is currently lower than the cost of renewable obligation certificates, when averaged over the lifetime of the project. Feed-in tariff is interpreted as a RPI-X regulation. It confirms to stimulate investment in renewable energy generation. Even if we could estimate that decreased costs due to technological progress is insufficiently transposed in the feed-in tariff (to the benefit of energy producers), differences of electricity prices between Germany and UK are low. We wonder on the conclusions we can obtain in France.

In our paper, we analyze simultaneously the impacts of competition and environmental policies, feed-in tariffs vs. the EU ETS, on investment decisions and generation choices in France. The following of the paper is organized as follows. In section2, we set out the main assumptions of the models. In section 3, using French public data, we simulate the equilibriums in different market structures and under different environmental policies. The final section concludes and provides some elements of discussion.

2 The model

We consider a model with several periods (years) denoted by $\theta = 1, \ldots, \Theta$. Within each period we consider infraperiods, denoted $t = 1, \ldots, T$, in order to take into account the seasonality of demand, i.e. on a monthly basis. Though our main focus is the impact of environmental policies on investment and prices neglecting uncertainties related to competition and to climate weather forecasts.

[2] i.e. reduce additional market failures.

2.1 Demand

The households' demand as well as public demand depend for most part on climate and consequently are seasonal. On the contrary, some industrials show a nearly flat demands. Thus, we consider two types of consumers[3]: consumers depending on temperatures, such as residential, commercial, public consumers (denoted by h) and the other ones (denoted by nh) that are not dependent on temperatures.

Consumer h. The inverse demand function of consumers h is defined by:

$$p_h(t,\theta) = \overline{p}_h - \alpha_h \frac{\overline{p}_h}{\overline{q}_h(t,\theta)} q_h(t,\theta), \tag{1}$$

where α_h is a positive constant and $\overline{p}_h$ is the price threshold. If the current price is greater than $\overline{p}_h$, the demand equals zero. $\overline{q}_h$ represents the seasonal demand and is defined by the following equation:

$$\begin{aligned} \overline{q}(t,\theta) &= \frac{4t^2(PKP(\theta) - BASE(\theta))}{[card(t)]^2} \\ &\quad - \frac{4t(PKP(\theta) - BASE(\theta))}{card(t)} + PKP(\theta). \end{aligned} \tag{2}$$

Note that $\int_0^{8760} \left(\frac{PKP(\theta)-BASE(\theta)}{8760}\tau + PKP(\theta) \right) d\tau$ is the annual demand for h in period θ when h are supplied at a regulated tariff, where $PKP(\theta)$ the peak demand and $BASE(\theta)$ the minimal demand for h in θ.

Consumer nh. The inverse demand function for these consumers is flat and defined by the following equation:

$$p_{nh}(t,\theta) = \overline{p}_{nh} - \alpha_{nh} \frac{\overline{p}_{nh}}{\overline{q}_{nh}(\theta)} q_{nh}(t,\theta), \tag{3}$$

where α_{nh} positive constant.

2.2 Supply

We assume that electricity is supplied by two types of producers denoted by a, the incumbent $(a = I)$ who is dominant and the others ones $(a = E)$ that is alternative and smaller producers aggregated in our study for convenience's sake. Both actors have already invested in generation capacities,

[3]Consequently, two markets (two prices) which avoid cross-subsidies.

$PED\,(1, c, a) \in R^{C \times A}$, where $card(C)$ is the number of generation technologies c considered and $A = \{I, E\}$.

Conceptually, the optimization problem to be solved initially for each actor a is thus:

Max [Net Present Value (NPV)]

Subject to constraints:

total supply produced by each actor a = total demand expressed by both consumers

for each actor a, installed available capacity $\geq$ supplied capacity

(plus some model specific constraints)[4]

Where,

The objective function of actor a implies to maximize its NPV. The NPV is the present profit generated by production over the 12 months, net of fixed and variable exploitation costs, and net of investment costs. The variable costs include fuel (i.e. gas and oil, coal, uranium) costs.

Production is sold by the incumbent at regulated tariffs to non eligible consumers or by any actor at market prices when consumers are eligible. Due to the evolution of regulation, we assume that consumers depending on temperatures are non eligible at first and become eligible in time. Nevertheless these two kinds of eligible consumers will not be supplied at the same market price on account of their different load profiles. Production supplies the demands expressed monthly by both kinds of consumers and cannot exceed the installed capacities which take into account lag of construction and decommissionning.

The model is modified as followed according the environmental policy we consider.

2.3 Environmental policies

2.3.1 Feed-in tariffs

In France, the incumbent is required to buy the electricity produced using renewable sources. Then it sells this quantity of electricity to the market. He is reimbursed by the difference between feed-in tariffs and the accounting average production cost according renewable source (cf. contributions to the

[4]These constraints mentioned are similar to Chaton (1998) and Chaton and Doucet (2003), without uncertainty and electricity trading, but with the addition of numerous periods. For ease of exposition, we only describe the problem. The complete model is provided in the appendix A at the end of the paper.

Electricity public service, CSPE). The other actors face a twoflod option: either the sell their electricity to the incumbent at feed-in tariffs or at market price to consumers. The modification of the basic model is detailed in Appendix B.

Remark: Feed-in tariffs can be viewed as direct subsidies which lower the exploitation unit cost of green-power stations.

2.3.2 The EU ETS

The EU ETS restricts emissions of european electricity actors. The constraints (i.e. allocations of quotas) are established at the national level by National Allocation Plans (NAPs). In France, the NAP set a constraint of 35.92 million tons of CO2 per year (MtCO2/y) for the first phase (2005-2007). It strengtens it for the second phase (2008-2012) with a decrease to 25.592 MtCO2/y. A. Piebalgs, the European Commissioner of energy, announced that he will present by the end of 2007 his project concerning emissions constraints for the third phase running from 2013 to 2018[5]. The NAPs transpose these sectorial constraints into installation-level allocations. Methods[6] used to determine installation-level allocations of quota, including baseline changes, commissioning and rationalisation rules and appeals against application of these rules. In France, allocations are based on "grandfathering". Quotas are allocated freely on the basis of historical emissions. But new entrants, except for extensions of plants, are allocated quotas according the Best Available Technologies (BAT) using the less pollutant fuel, natural gas.

Firms receive quotas and can buy additonnal permits or sell permits if they have somme in excess on the EU ETS. Their objective functions take into account the balance of these quotas exchange. Because the EU ETS is an European market which concerns some industrial sectors as well as energy sectors, we assume that the price of quota is exogeneous. The modification of the basic model is detailed in Appendix C.

[5] These constraints will take into account the aims already fixed By the European Commission: -20% of CO2 emissions, +20% for energy efficiency and a share of 20% of renewable energy in the electricity mix by 2020.

[6] The EU ETS allows two means to allocate quotas : "grandfathering" and Best Available Technologies (BAT). In BAT, the emission factor is fixed according the fuel or the less pollutant fuel (i.e. natural gas). See C. Levy (2005) for a good description of the EU ETS.

3 Simulations

3.1 Data

The model is applied to public data on the French market (cf. DGEMP, 2003, 2006, 2007). We use GAMS with MINOS to solve these three optimization problems, so that we can compare them, over 15 years (from February[7] 2006 to January 2021). By hypothesis, the discount rate equals 5%.

3.1.1 Demand

In France, professional consumers became eligible in July 2004 and the other ones, the residential consumers became eligible in July 2007. Since then they have then the choice to be supplied by the incumbent at a regulated tariff approved by the government (more precisely by the ministry in charge of economy, finance and industry) after notice of the regulator, CRE[8]. This regulated tariff should exist until July 1^{st} 2010, but could be removed at every moment.

In broad outline, we assume that consumers depending on temperatures are non eligible during the first two years, from February 2006 to March 2008. They pay a regulated tariff established by the government at 0.1029 euros per kilowatt hour (€/kWh) the first year and 0.1203 €/kWh the second year. Then they become eligible such as the other ones who are independant to temperatures[9]. So they can be supplied either by the incumbent or by the others operators.

Demands of consumers are described below. Base and peak loads of consumers h when they are not eligible are equal to: $BASE\,(1) = 23$ gigawatt hours (GWh), $BASE\,(2) = 23.4$ GWh, $PKP\,(1) = 37.4$ GWh and $PKP\,(2) = 36.1$ GWh. For the following years ($\theta \geq 3$), when consumers h are eligible, base and peak loads do not increase. Load profiles of consumers nh are characterized by $\overline{q}_{nh}\,(1) = 9.8$ GWh, $\overline{q}_{nh}\,(2) = 9.9$ GWh and increase by 2% for the following years. To calibrate demands, we assume $\alpha_h = 1.8$ and $\alpha_{nh} = 1$. Price thresholds for both types of consumers are defined in the table. We suppose that the prices thresholds are constant for the climate

[7] In order to switch well real demands and peak loads, year begins in February.

[8] Commission de la Régulation de l'Energie.

[9] We don't take into account the fact that eligible professional customers can ask to their supplier (incumbent or entrants) to benefit from the regulated tariff, TaRTAM (tarif réglementé transitoire d'ajustement du marché), that is implemented on January 5th 2007. This regulated tariff includes a penalty, but is not volatil as market prices, and is available only for a determined and transitory period.

independent customer. On the contrary, the climate dependent customer are ready to pay expensive bills during winter.

Months	$\overline{p}_h$	$\overline{p}_{nh}$
1 (February)	1.9	0.8
2 (March)	1.2	0.8
3 (April)	1.2	0.8
4 (May)	1.1	0.8
5 (June)	1.1	0.8
6 (July)	1.1	0.8
7 (August)	1.1	0.8
8 (September)	1.3	0.8
9 (October)	1.7	0.8
10 (November)	1.9	0.8
11 (December)	1.9	0.8
12 (January)	1.9	0.8

3.1.2 Supply

Technologies. We consider 10 technologies ($card(C) = 10$). These technologies include Nuclear Power Plants (NPPs), large hydroelectric plants (HCHPs) and small hydroelectric plants (SCHPs), two technologies of coal-fired power plants which differ on costs and emissions (pulverized coal, COAL1, and flue gas desulphurization process, COAL2), combined cycle gas turbines (CCGTs), wind turbines (WIND), solar PV (SOLAR), fuel power plants (FUEL) and gas turbines (GTs). We do not consider biomass because investment costs are dependant on the size of plants and doesn't allows us to estimate unified costs per kWh. Morever, we do not take into account technical progress. For example, we do not integrate last coal based generation technologies such as those carbon captage and storage (CCS) which is not yet profitable. There is a scientific debate on this question, and in May 2007 a panel of experts on CCS told US legislators that the technology is ready for large-scale demonstration projects to speed its development, making it commercially viable in the next decade.

Initial capacities of actors. The assumed initial capacities of the incumbent are presented in the table below. The actor $E's$ aggregated capacities located in France include those of Suez (with two subsidiaries, CNR[10]

[10] Compagnie Nationale du Rhône.

and SHEM[11]), Endesa France and Gaz de France.

Generating technology (MW)	Incumbent I	Entrant E	Construction duration β_c
NPP	62840	0	7
HCHP	18800	2.937	4
SCHP	1800	0.773	2
COAL1	7042	2.477	5
COAL2	993	0	5
CCGT	0	0	4
WIND	228	0	1
SOLAR	0	0	1
FUEL	7521	0	2
GT	203	2.39	2

We assume that there is no possibility to invest in HCHP and that total investment in SCHP is bounded up to 2 GW. We do not detail here the investment and exploitation costs, which can be found in DGEMP (2003).

Remark: Hydropower is not considered as an avoided cost.

Availability functions. These functions noted $DISP(d, c)$, and defined in Appendix A, depend on technology type c and the number of operating hours (see Table in appendix D for the value of parameters). We assume that solar PV stations do not produce during the following months: March, October, November, December and January.

Fuel costs. We consider the lowest scenario given by DEGMP (2003). Hence, in February 2006, we have the following values for the price of the various fuels: 3.3 \$/MBtu[12] for gas; 177.3 euros per cubic meter (€/m^3) for oil; 30\$/ton for coal and 4.4 €/MWh for uranium. The increase of oil (respectively gas) price is equal to 5% (respectively 3%) per year. The other prices are assumed constant[13].

Emissions. Below, for each scenario (without and with each environnmental policy) we determine CO2 emissions due to production by considering the DGEMP emission factors, given for new plants built in 2007 and in 2015 (which emit less).

[11] Société Hydroélectrique du Midi.

[12] Dollars per one million British Thermal Unit.

[13] This assumption for coal and uranium is justified by the existence of long term contracts and the possibility of storage.

3.2 Results

Impacts of environmental policies are analyzed according to the cost beared by the society, to CO2 emissions and to improvement in competition.

3.2.1 The basic model as a benchmark

Investment The incumbent does not invest. Starting from the first year, the entrant diversifies his generation capacities for the future. His investment is mainly composed of thermal stations, of gas turbines (GTs then CCGTs) accounting for 57% of the total investment, followed by coal-fired plants (16%). The entrant even invests in NPPs the first two years. 27% of his investment does not emit carbon.

Remark : He saturates his hydroelectric capacity constraint.

FIG 3

Production The main share of demand is still supplied by the incumbent (cf. appendix E). We present technologies used to supply demands.

NPPs still supply baseload demand. We can note that hydroelectric capacities are more or less used according to seasons. HCHPs operate fully during winter but less during summer. In 2013 and 2014, these plants also operate during summer as a result of cost reduction of the entrant following the entrant's NPPs coming into service.

FIG 4

Competition Climate independent customers benefit from decreasing prices by 2008 whereas climate dependent customers suffer a sudden and significant increase as tariff regulation is abandoned. More competition (i.e. the eligibility of climate dependent customers) seems to favour those customers whose consumption is not highly sensitive to climate change as they benefit of a decrease in prices. The need to satisfy peak load demand for climate dependant customers can explain higher levels of price and increased volatility. Finally, before February 2008, climate independent customers paid for climate dependent customers who benefit from regulated tariffs.

FIG 5

CO2 emissions The incumbent does not emit CO2 because it uses only the nuclear thermal power stations and the hydroelectric plants. On the other hand, the emissions of CO2 of the entrant can reach 60.9 MT (see figure 6).

FIG 6

3.2.2 Feed-in tariffs considered as an environmental policy

Feed-in tariffs are implemented in France and since 2006 amount to 0.30 €/kWh for solar energy. For wind energy, they amount to 0.082 €/kWh for the first 10 years and then, for the 5 following years, will decreas to a value in between 0.082 €/kWh and 0.028 €/kWh according to the operating hours of windmills.

We suppose that the quantities produced by the entrant's solar PV and windmills sold to the incumbent at feed-in-tariffs and satisfy part of the demand of climate independent customers. Consequently, the inverse demand function of these customers (i.e. equation (3)) can be rewritten as follows:

$$p_{nh}\left(t,\theta\right)=\overline{p}_{nh}-\alpha_{nh}\frac{\overline{p}_{nh}}{\overline{q}_{nh}\left(\theta\right)}\left[q_{nh}\left(t,\theta\right)-QGS(t,\theta,E)-QGW(t,\theta,E)\right], \quad (4)$$

where $QGS(.)$ and $QGW(.)$ (in kWe) are the quantities produced by the entrant's solar PV and windmills to be sold to the incumbent at feed-in tariffs.

Investment The incumbent does not invest. The entrant's investment is diversified and is composed mainly renewable energy and hydroelectric plants (87%). The entrant does not invest anymore in NPPs, but still saturates his hydroelectric capacity constraint. He also invests in thermic plants, in gas turbines (GTs then CCGTs) with 12% of total investment, and marginally in coal-fired plants (1%).

FIG 7

Of course, the results depend on some unrealistic assumptions. Indeed, on the one hand, the entrant hasn't got any financing constraint, and on the other hand the investments in solar PV and windmills are not indefinitely scaleable (for examples, because of weather conditions, of hesitation of public opinion in the setting-up of these power plants in their neighbourhood[14] or of the incapacity of renewable technologies producers of to supply the total demand of electricity producers).

Nevertheless, the objective here is to determine the optimal investment by considering only the environmental constraints and to compare this case with the unconstrained one.

Production The main part of demand is still supplied by the incumbent (cf. appendix E). We present technologies used to supply demands.

FIG 8

According to the demand specification adopted for the climate independent customers, the quantities sold at the feed-in tariffs, $QGS(.)$ and $QGW(.)$, satisfy the maximum demand $\overline{q}_{nh}(\theta)$ of these consumers. They satisfy between 26% (in 2010/01) and 50% (in 2019/08 and in 2020/05) of the total demand. The incumbent is obliged to purchase these (exogeneous for him) quantities that replace the nuclear power production.

Competition Quantities $QGS(.)$ and $QGW(.)$ generate important incomes for the entrant, that become costs for the incumbent. Because of the CSPE, a part of these costs must then be supported by the consumers (and this is not taken into account in our analysis) and by the State (that we only assume here).

This type of policy seems to be beneficial for climate independant customers (who experience lower prices and hence increase in their consumption of electricity), while the climate dependent customer suffer a weakening of their initial situation.

FIG 9

Let us stress that this conclusion is to be mitigated. Indeed, insofar as the incumbent has an obligation to take the quantities $QGS(.)$ and $QGW(.)$, these quantities are not decision variables for the incumbent who optimizes

[14]cf. the NYMBY syndrom.

his production omitting these quantities (see equation (9) in appendix B). It follows that the demand function of the climate independent customers which is addressed to the operators is the residual demand. This residual demand is equal to zero because $QGW(.)$ and $QGS(.)$ satisfy the maximum demand of independent climate customer (at null price).

FIG 10

However these consumers should bear the cost of the CSPE and thus reduce their demand. An extension of the model would be to take into account this subsidy.

The nondiscounted annual cost for the incumbent which represents the environmental policy cost for the society is represented in the figure 11.

FIG 11

CO2 emissions Over the studied period (2006/02- 2021/01) the CO2 emissions are reduced by 40% (665Mt to 399Mt).

As of the thrid year, the reduction is effective as of the thrid year (- 25%). Thus, this policy makes it possible to achieve the objective of reduction in the CO2 emissions but at a cost which is important for the incumbent and which then will be reflected on the consumers.

FIG 12 - 13

3.2.3 The EU ETS considered as environmental policy

We do not take explicitely into account the EU ETS because it is endogeneous and the electricity sector is not the only activity in which emissions are constrained. We can notice also that the French generation mix does not emit a lot of CO2 besause it includes NPPs and hydropower plants. Furthermore the historical prices of emission permits do not seem to ease forecasts of prices in the future. At the end of the first phase, the prices of permits have fallen to nearly zero because actors on this EU ETS realized that they have been allocated excess permits and banking[15] was not allowed.

We model the outcome of the EU ETS game as yearly emission caps, but without taking into account trade of permits which are allocated according to the installation-level allocation method (described for the second phase in appendix C and which can be revised for the third phase). Note that we test this allocation method with various emission prices resulting from exchanges on the EU ETS. We find that the actors anticipate the decreasing cap and emit more during the first years in order to receive more quotas during the following years. Thus, we tested the following caps without permits trade. We considered, in each case, a cap of 35 CO2 Mt/y from February 2005 to January 2008. Then, the threshold equals to:

- 25 CO2 Mt/y from February 2008 to January 2021 (case 1);
- 20 CO2 Mt/y from February 2008 to January 2021 (case 2);
- 15 CO2 Mt/y from February 2008 to January 2021 (case 3).

Investment In each of the 3 cases, the entrant invests more into solar PV, wind turbines and NPPs instead of fossil-fired power stations (see Table 7-9)

FIG 14 - 16

Competition Case 1: The profits are relatively stable (+1.74% for the incumbent and -1.47% for the entrant). The demand of the climate independent customer supplied by the entrant is the more sensitive. The variation of total demand is contained between -10% and 10%.

Case 2: The reduction in profit for the entrant becomes consequent (-3.2%), the incumbent always experience a profit increase (+1%).

Case 3: the profit of the incumbent is always higher than in the benchmark case (+1.4%) and the profit of the entrant decreases (- 1.6%).

Demand variations are compared to the benchmark case.

FIG 17 -18

[15] The banking is the possibility given to EU ETS' actors to use permits given in a phase in the following one.

CO2 emissions Case 1: The CO2 emissions are reduced by 50% compared to the benchmark case.

Case 2: The emissions are reduced by more than 65%.

Case 3: The emissions decrease by approximately 71%.

4 Conclusion

Our model permits to analyze the consequences of environmental policies on the electricity market. We respectively test the impact of feed-in-tariffs and quotas obligation systems on decisions of an incumbent and its competitors, aggregated and denominated alternative producers. Our results show that the two policies contribute to reduce CO2 emissions. Nevertheless, the second policy that is EU ETS seems more effective (forced reduction in emissions, without loss of profits for both producers). For the consumers, the variations of the demand due to the taking into account quotas is about +/- 10% (according to month and year).

The retained feed-in tariff policy seems more expensive for the "social welfare" and less effective fin terms of emissions reduction. In that we are in line with theoretical literature on feed in tariffs and quotas obligation system (Menanteau, Finon Lamy, 2003 ; Böhringer, Hoffman, Rutherford, 2006).

As our goal was to focus on a comparison of environmental policies efficiency we did subscribe to a set of assumption that could be adapted to broaden the issues under study. Therefore, the model can be extended in several directions to illustrate other topical stakes on the electricity market. Firstly release measures can be introduced in order to allow the entrant to penetrate the market without capacity. Furthermore we can introduce risks relative to the environmental policies, which could slow down the investments in renewable energies, At last, we can take into account various options of investment while introducing uncertainty.

5 References

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6 Appendix A: the basic model

The objective function for actor a is such as:

$$\begin{aligned}
&\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}\left(p_h(\theta,t)\,q_h(\theta,t,a)+p_{nh}(\theta,t)\,q_{nh}(\theta,t,a)\right)\frac{8760}{card\,(t)} \qquad (5)\\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{c=1}^{C}\left(\eta_c PED\,(\theta,c,a)+\iota_c PEI\,(\theta,c,a)\right)\\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}\sum_{d=1}^{T}\sum_{c=1}^{C}\left(\omega_c+p_{c,a}r_c\right)PEF\,(\theta,t,d,c,a)\frac{8760}{card\,(t)}
\end{aligned}$$

where:

η_c (in euros per kilowatt of electricity or €/kWe) is the exploitation unit cost for the station type c;

ι_c (in €/kWe) is the investment unit cost for the station type c;

ω_c and r_c are non negative constants and r_c is the return of the station c;

$p_{c,a}$ is the price of the fuel used by the power station type c by producer a. Fuel prices are different for each producer according to the existence of long-term contracts (i.e. gas, nuclear);

$PEF\,(\theta,t,d,c,a)$ is the supplied electric power by the plant of type c by the generator a, used in the infraperiod t and in $(d-1)$ other infraperiods, d integer such as $1 \leq d \leq T$;

$PEI\,(\theta,c,a)$ is the new capacity purchased by the producer a for the station type c;

$PED\left(\theta,c,a\right)$ is the amount of the existing capacity of station type c of the producer a, in the period θ, which is defined by:

$$PED\left(\theta,c,a\right)=PED\left(\theta-1,c,a\right)-DEC\left(\theta,c,a\right)+PEI\left(\theta-\beta_{c},c,a\right),$$

where β_c is the construction duration of station type c;

$DEC\left(\theta,c,a\right)$ the amount of decommissionning for station type c of the producer a in period θ.

The constraints describing the power generation system are the following.

First, the supply constraints state that the capacity allocated cannot exceed the purchased. Then the bounds on production due to the installed capacities and the availability rates must be verified as

$$\sum_{d=1}^{T}\frac{\sum_{t=1}^{T}PEF\left(\theta,t,d,c,a\right)}{DISP(d,c)}\leq PED\left(\theta,c,a\right),\ \forall\theta,c,a. \tag{6}$$

The avaibility factor of a power station, denoted by $DISP(d,c)$ depends on the technology c, the number of operating hours $(d\frac{8760}{12})$ and climatic conditions. Note that this factor includes the average rate of the maintenance and the rate unscheduled outage. The latter is random. Yet, here, one passes over the disturbance term.

$$DISP(d,c)=\alpha_d+\beta_d d\frac{8760}{12}$$

The second constraint is inherent in the definition of $PEF\left(\theta,t,d,c,a\right)$, see Chaton (1998) for demonstration:

$$\sum_{t=1}^{T}PEF\left(\theta,t,d,c,a\right)-d.PEF\left(\theta,k,d,c,a\right)\geq 0,\ \forall\theta,k,d,c,a. \tag{7}$$

Third, for each producer a, the demand constraints state that the total supply of a in the infraperiod t in the period θ must be equal to the demand of the consumers depending on the temperature and the demand of the other consomers expressed to a:

$$\sum_{d=1}^{T}\sum_{c=1}^{C}PEF\left(\theta,t,d,c,a\right)=q_h\left(\theta,t,a\right)+q_{nh}\left(\theta,t,a\right),\ \forall\theta,t,a. \tag{8}$$

7 Appendix B: feed-in tariffs as environmental policy

The model is modified as followed according the policies we consider. Feed-in tariffs can be viewed as direct subsidies (taxation) which lower the exploitation unit cost for green-power stations.

The entrant E keeps the option to sell his electricity at feed-in tariffs to the incumbent or at the market price to consumers.

The objective function of the incumbent E becomes:

$$\begin{aligned}
&\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}\left(p_{nh}\left(\theta,t\right)q_{nh}\left(\theta,t,E\right)+PGS\left(t\right).QGS\left(\theta,t,E\right)+PGW(t).QGW\left(\theta,t,E\right)\right)\tfrac{8760}{card(t)} \\
&\quad+\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}p_{h}\left(\theta,t\right)q_{h}\left(\theta,t,E\right)\tfrac{8760}{card(t)} \\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{c=1}^{C}\left(\eta_{c}PED\left(\theta,c,E\right)+\iota_{c}PEI\left(\theta,c,E\right)\right) \\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}\sum_{d=1}^{T}\sum_{c=1}^{C}\left(\omega_{c}+p_{c,E}r_{c}\right)PEF\left(\theta,t,d,c,E\right)\frac{8760}{card\left(t\right)}
\end{aligned} \tag{9}$$

where $QGS(.)$ and $QGW(.)$ (in kWe) are the quantities produced by solar PV and windmills to be sold to the incumbent at feed-in tariffs $PGS\left(t\right)$ and $PGW(t)$.

According to the 2006 annual conference of SER[16] and the JO[17] order of July 10^{th} 2006, feed-in tariffs for solar PV are equal to 0.30 €/kWh during 15 years. Feed-in tariffs for windmills are equal to 0.82 €/kWh during 10 years and, during 5 years more, to:

- 0.028 €/kWh if windmills produce during 3650 hours and more;
- 0.068 €/kWh if windmills produce between 2190 and 3650 hours;
- 0.082 €/kWh if windmills produce during 2190 hours and less.

To simplify, we linearize these feed-in tariffs according to operating hours.

The incumbent is obliged to buy these two quantities, $QGS(.)$ and $QGW(.)$, produced by the entrant. He is reimbursed by the CSPE. We assume that

[16] Syndicat des Energies Renouvelables.

[17] Journal Officiel.

he sells these quantities to independent climate customers. The objective function of the incumbent I becomes:

$$\begin{aligned}
&\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T} p_{nh}(\theta,t)\left[q_{nh}(\theta,t,I)-QGS(\theta,t,E)-QGW(\theta,t,E)\right]\tfrac{8760}{card(t)} \\
&\quad+\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T} p_{h}(\theta,t)\,q_{h}(\theta,t,I)\,\tfrac{8760}{card(t)} \\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{c=1}^{C}\left(\eta_c PED(\theta,c,I)+\iota_c PEI(\theta,c,I)\right) \\
&\quad-\sum_{\theta=1}^{\Theta}\sum_{t=1}^{T}\sum_{d=1}^{T}\sum_{c=1}^{C}\left(\omega_c+p_{c,I}r_c\right)PEF(\theta,t,d,c,I)\,\frac{8760}{card\,(t)}
\end{aligned} \tag{10}$$

8 Appendix C: the EU ETS as environmental policy

In France, both generators are submitted to an additionnal constraint which represents the policy with quotas. During each period (year), emissions must be lower than a threshold of quotas:

$$\sum_{d=1}^{T}\sum_{c=1}^{C}\varphi_c PEF(\theta,t,d,c,a)\leqslant S(t),\ \forall t,a \tag{11}$$

where φ_c is the emissions factor of station c and $S(t)$ (in CO2 tons) are emissions thresholds during the period t and are constants.

We do not take into account the formula described for the second phase for which installation-level allocations of quota $S(t)$ depend on emissions and investments of the previous periods:

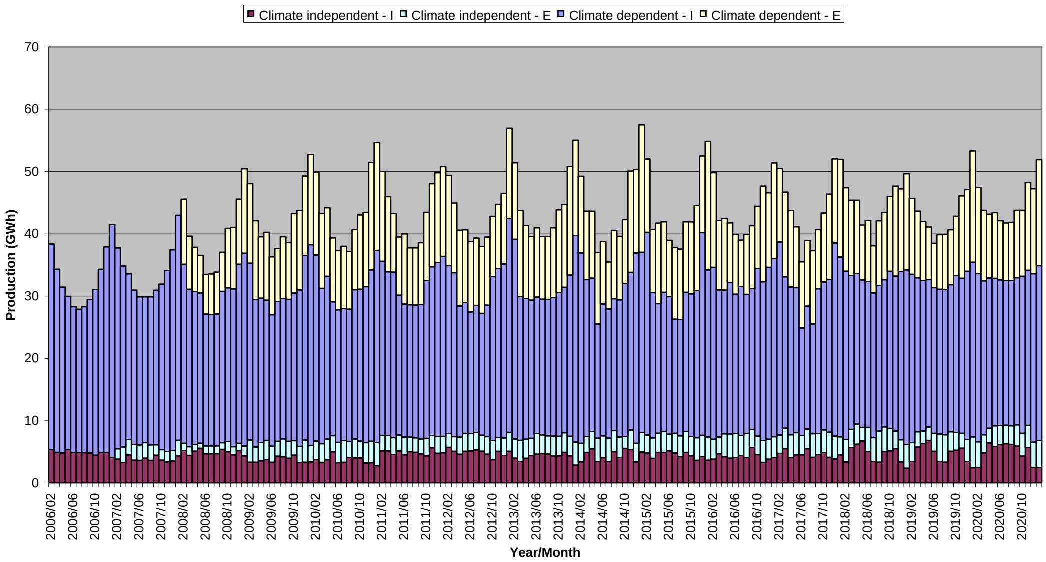
$$\begin{aligned}
S(t+1) &= \sum_{d=1}^{T}\sum_{c=1}^{C}\left(r.g\,(1-0.025)\right)\varphi_c PEF(\theta,t,d,c,a) \\
&\quad+\sum_{c=1}^{C} h_c\Phi(\theta,c)\,PEI(\theta,t,a)\,,\ \forall\theta,t,a
\end{aligned} \tag{12}$$

where r and g are two positive constants, a rate defined by the NAP and the GNP rate; $\Phi(\theta,c)$ is the emissions factor of new station c built after the first period; h_c is the functionning hours of each new station c defined in the NAP.

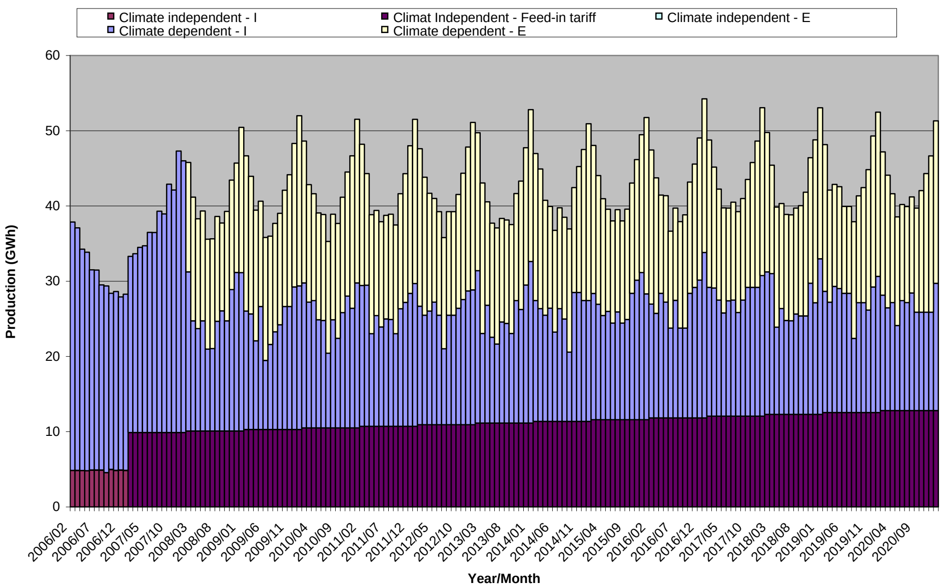
9 Appendix D: Availability factor

Number of operating hours 8760 d /12	<= 1000 hours		]1000;4000] hours		>4000 hours	
Generating technology						
NPP	0.98446016	-9.37E-06	0.98446016	-9.37E-06	0.98446016	-9.37E-06
HCHP	0.9	0	0.9	0	0.9	0
SCHP	0.97	0	0.97	0	1.10315455	-3.67E-05
COAL1	0.94494167	-7.28E-06	0.94494167	-7.28E-06	0.93511209	-3.67E-06
COAL2	0.94494167	-7.28E-06	0.94494167	-7.28E-06	0.93511209	-3.67E-06
CCGT	0.95636755	-4.15E-06	0.95636755	-4.15E-06	0.95636755	-4.15E-06
WIND	0.27	0	0.27	0	0.27	0
SOLAR	0.34	0	0.34	0	0.34	0
FUEL	0.97	0	0.97309999	-8.83E-06	0.97309999	-8.83E-06
TACG	0.97	0	0.97309999	-8.83E-06	0.97309999	-8.83E-06

10 Appendix E: Production according actors in the benchmark scenario



Demand (benchmark)



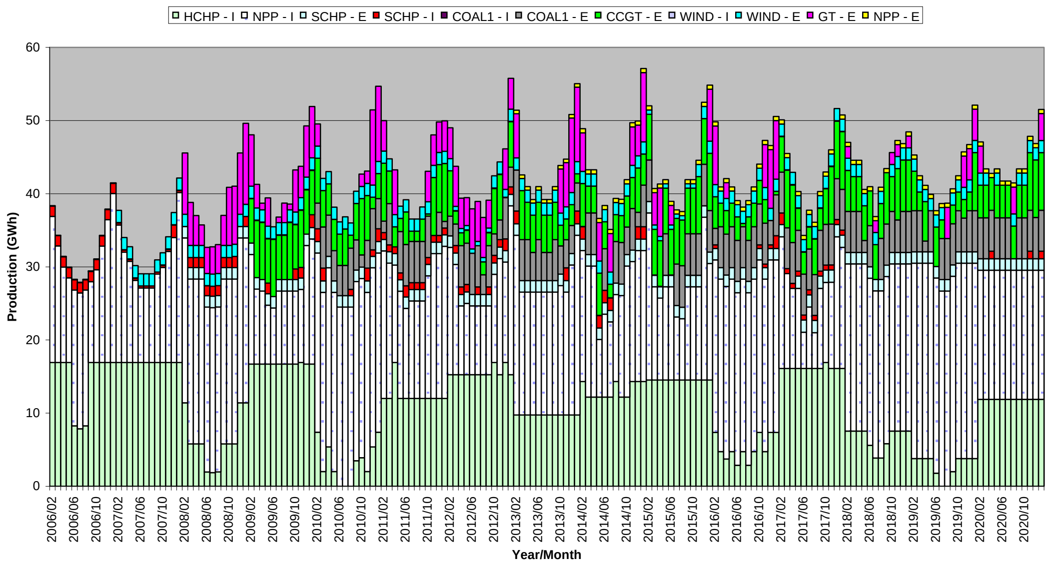
Demand (feed-in-tariffs)

11 Appendix F: Figures

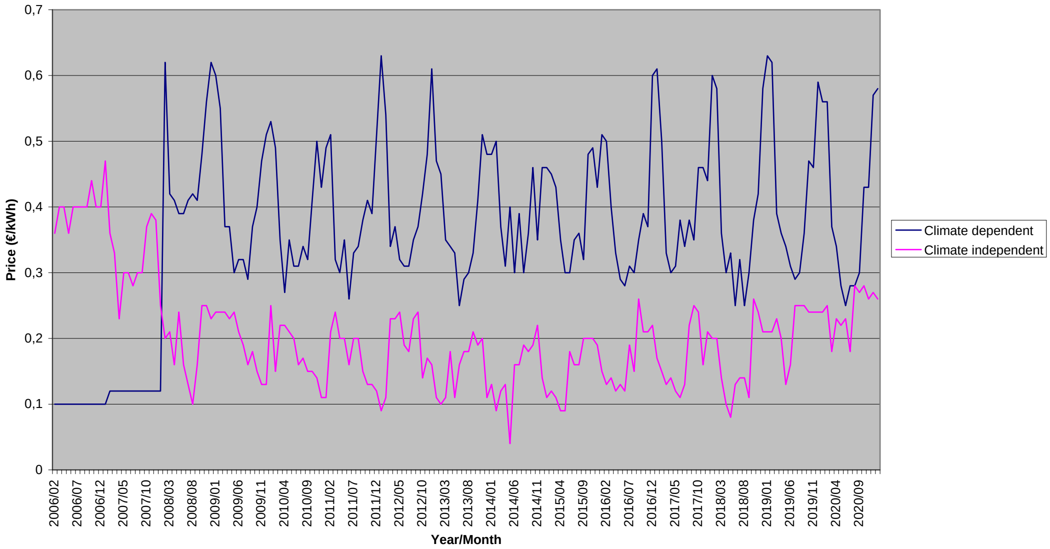
11.1 Benchmark scenario

Investment (GW)	NPP-E	SOLAR-E	WIND-E	SCHP-E	CCGT-E	GT-E	COAL1-E	COAL2-E
2006-2007	0.53	2.42	6.16	2.00	8.45	15.27	6.18	0.38
2007-2008	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.03
2010-2011	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00
	0.62	2.42	6.16	2.00	8.45	15.27	6.23	0.41

Investment according to technology for the entrant



Technologies used to supply demands



Prices in time for both customers

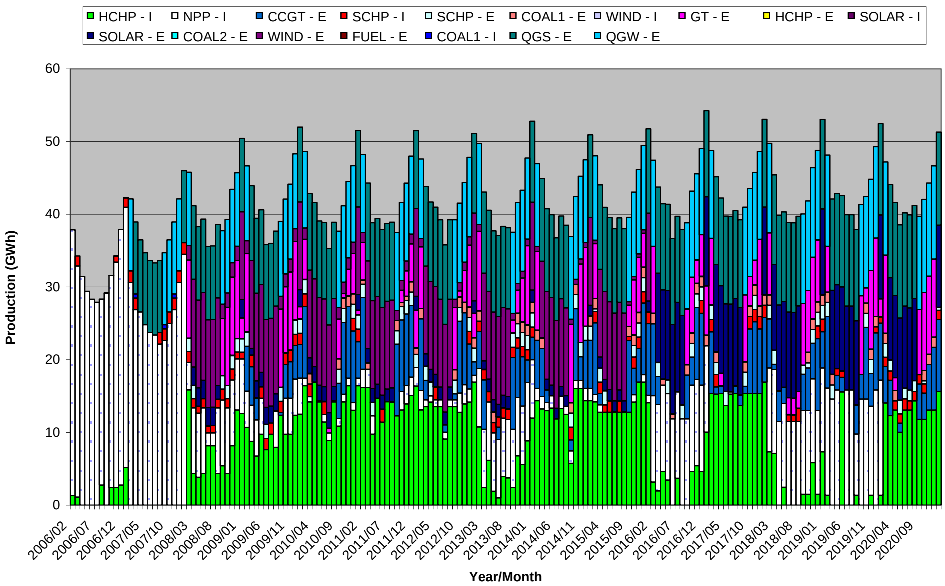
CO2 emission (Gt)	Incumbent	Entrant	Total
2006-2007	0.00	0.02	0.02
2007-2008	0.00	0.02	0.02
2008-2009	0.00	31.58	31.58
2009-2010	0.00	40.74	40.74
2010-2011	0.00	31.58	31.58
2011-2012	0.00	40.74	40.74
2012-2013	0.00	57.94	57.94
2013-2014	0.00	52.08	52.08
2014-2015	0.00	60.89	60.89
2015-2016	0.00	61.73	61.73
2016-2017	0.00	57.28	57.28
2017-2018	0.00	59.24	59.24
2018-2019	0.00	58.38	58.38
2019-2020	0.00	57.75	57.75
2020-2021	0.00	55.27	55.27
Total	0.00	665.24	665.24

CO2 emissions according actors (Benchmark)

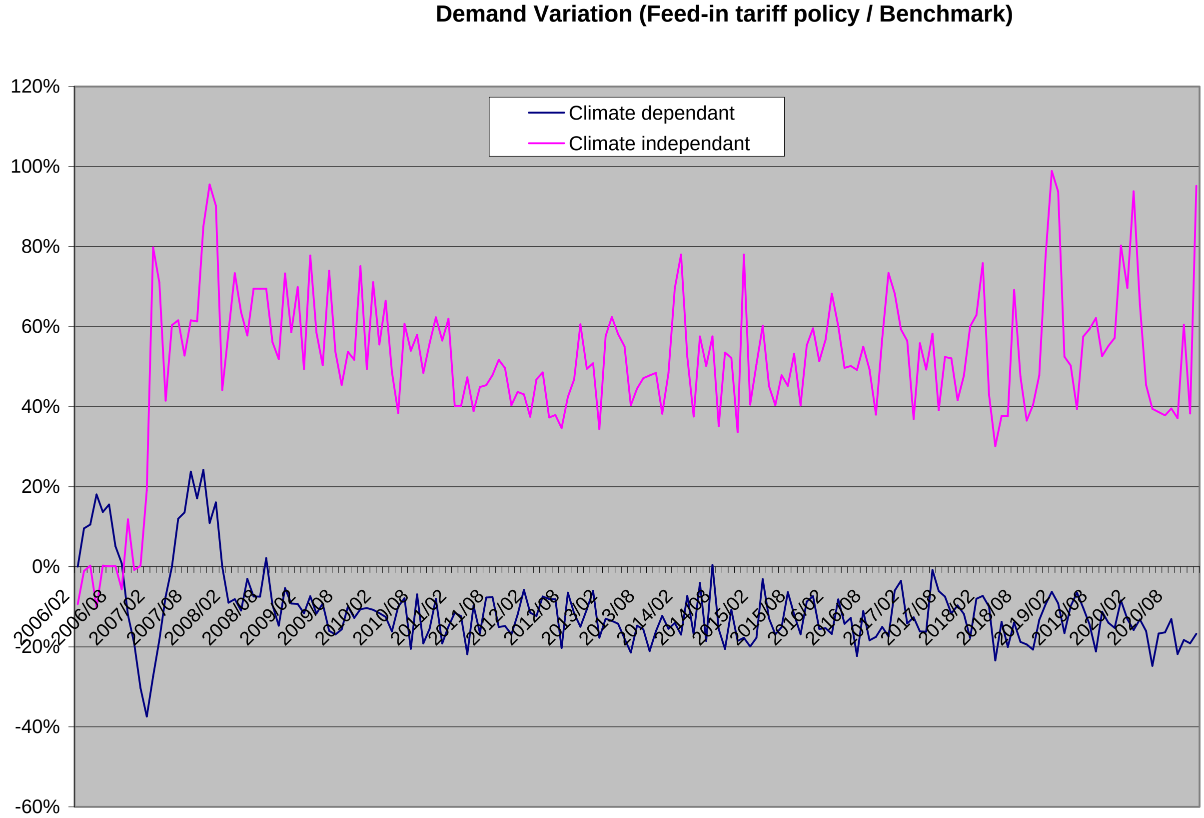
11.2 Feed-in-tariffs

Investment (GW)	SOLAR-E	WIND-E	SCHP-E	CCGT-E	GT-E	COAL2-E
2006-2007	29.12	36.67	2.00	8.45	15.27	0.00
2007-2008	1.18	3.82	0.00	0.00	0.00	0.00
2008-2009	0.00	0.00	0.00	0.00	0.00	1.26
2009-2010	0.61	0.00	0.00	0.00	0.00	0.00
2010-2011	0.62	0.00	0.00	0.00	0.00	0.00
2011-2012	0.63	0.00	0.00	0.00	0.00	0.00
2012-2013	0.64	0.81	0.00	0.00	0.00	0.00
2013-2014	0.66	0.83	0.00	0.00	0.00	0.00
2014-2015	0.67	0.84	0.00	0.00	0.00	0.00
2015-2016	19.42	29.93	0.00	0.00	0.00	0.00
2016-2017	3.70	3.67	0.00	0.00	0.00	0.00
Total	57.23	76.56	2.00	8.45	15.27	1.26

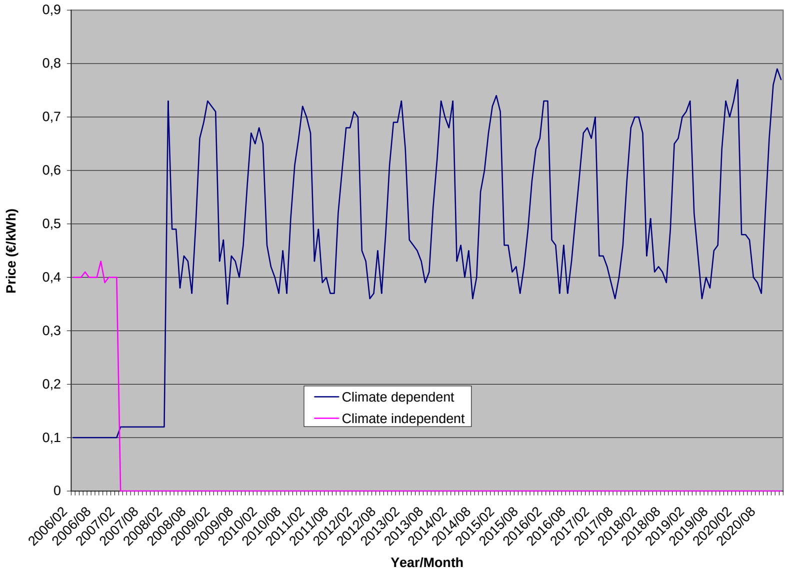
Investment (feed-in-tariffs)



Technologies used to supply demands under the feed-in tariffs policy



Demand variation between the feed-in tariff policy and the benchmark for both customers



Prices in time for both customers

Year	Cost
2006-2007	0.00E+00
2007-2008	9.28E+09
2008-2009	9.18E+09
2009-2010	9.36E+09
2010-2011	9.64E+09
2011-2012	9.67E+09
2012-2013	9.91E+09
2013-2014	1.11E+10
2014-2015	1.01E+10
2015-2016	1.08E+10
2016-2017	1.12E+10
2017-2018	1.11E+10
2018-2019	1.40E+10
2019-2020	1.18E+10
2020-2021	1.17E+10

Costs for the incumbent (feed-in tariffs)

CO2 emission (Gt)	Incumbent	Entrant	Total
2006-2007	0.00	0.02	0.02
2007-2008	0.96	0.00	0.96
2008-2009	0.00	23.61	23.61
2009-2010	0.00	32.57	32.57
2010-2011	0.00	23.61	23.61
2011-2012	0.00	32.57	32.57
2012-2013	0.00	26.79	26.79
2013-2014	0.00	25.73	25.73
2014-2015	0.00	31.00	31.00
2015-2016	0.00	30.67	30.67
2016-2017	0.00	34.42	34.42
2017-2018	0.00	30.42	30.42
2018-2019	0.00	34.78	34.78
2019-2020	0.00	34.29	34.29
2020-2021	0.00	37.48	37.48
Total	0.96	397.93	398.89

CO2 emissions according actors (feed-in tariffs)

CO2 emission (Gt)	Incumbent	Entrant	Total
2006-2007	0.00	0.02	0.02
2007-2008	0.00	0.02	0.02
2008-2009	0.00	31.58	31.58
2009-2010	0.00	40.74	40.74
2010-2011	0.00	31.58	31.58
2011-2012	0.00	40.74	40.74
2012-2013	0.00	57.94	57.94
2013-2014	0.00	52.08	52.08
2014-2015	0.00	60.89	60.89
2015-2016	0.00	61.73	61.73
2016-2017	0.00	57.28	57.28
2017-2018	0.00	59.24	59.24
2018-2019	0.00	58.38	58.38
2019-2020	0.00	57.75	57.75
2020-2021	0.00	55.27	55.27
Total	0.00	665.24	665.24

Reduction of CO2 emissions in comparaison to the benchmark

11.3 Quotas

Investment (GW)	CCGT-I	NPP-E	SOLAR-E	WIND-E	SCHP-E	CCGT-E	GT-E	COAL1-E	COAL2-E	FUEL-E
2006-2007	0.00	2.46	0.00	9.21	2.00	5.32	6.76	0.00	0.00	0.77
2007-2008	0.00	0.00	4.08	12.97	0.00	0.00	0.00	0.00	0.00	0.00
2008-2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74	0.00	0.00
2010-2011	1.25	0.00	0.00	0.00	0.00	0.00	0.00	1.20	0.00	0.00
2011-2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00
2013-2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00
2014-2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00
Total	1.25	2.46	4.08	22.18	2.00	5.32	6.76	2.36	0.00	0.77

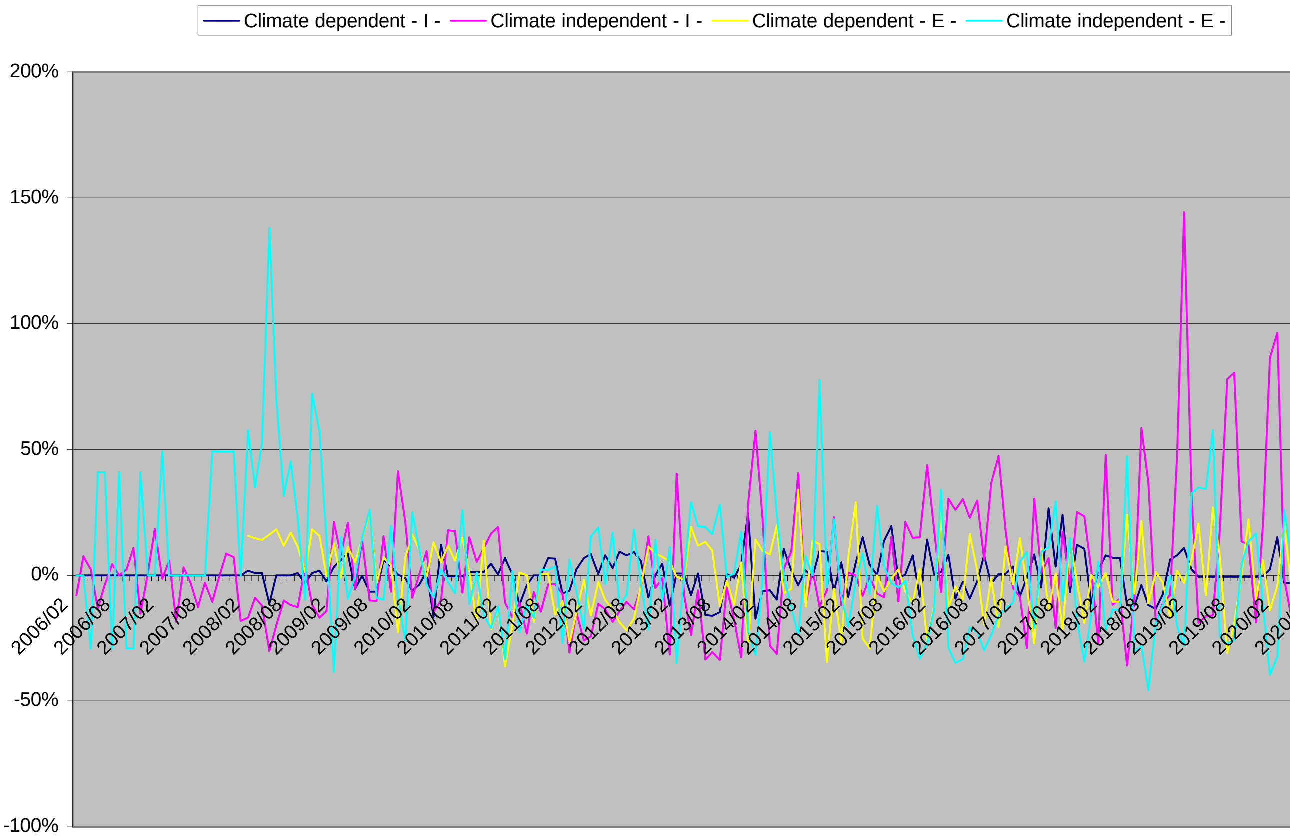
Investment (EU ETS - Case 1)

Investment (GW)	NPP-E	WIND - E	SCHP-E	CCGT-E	GT-E	COAL1-E	COAL2-E
2006-2007	1.78	9.21	2.00	5.14	3.88	1.37	0.00
2007-2008	0.00	18.90	0.00	0.00	0.00	0.34	0.00
2008-2009	0.00	0.00	0.00	0.00	0.00	0.00	0.57
2009-2010	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Total	1.78	28.11	2.00	5.14	3.88	1.71	0.63

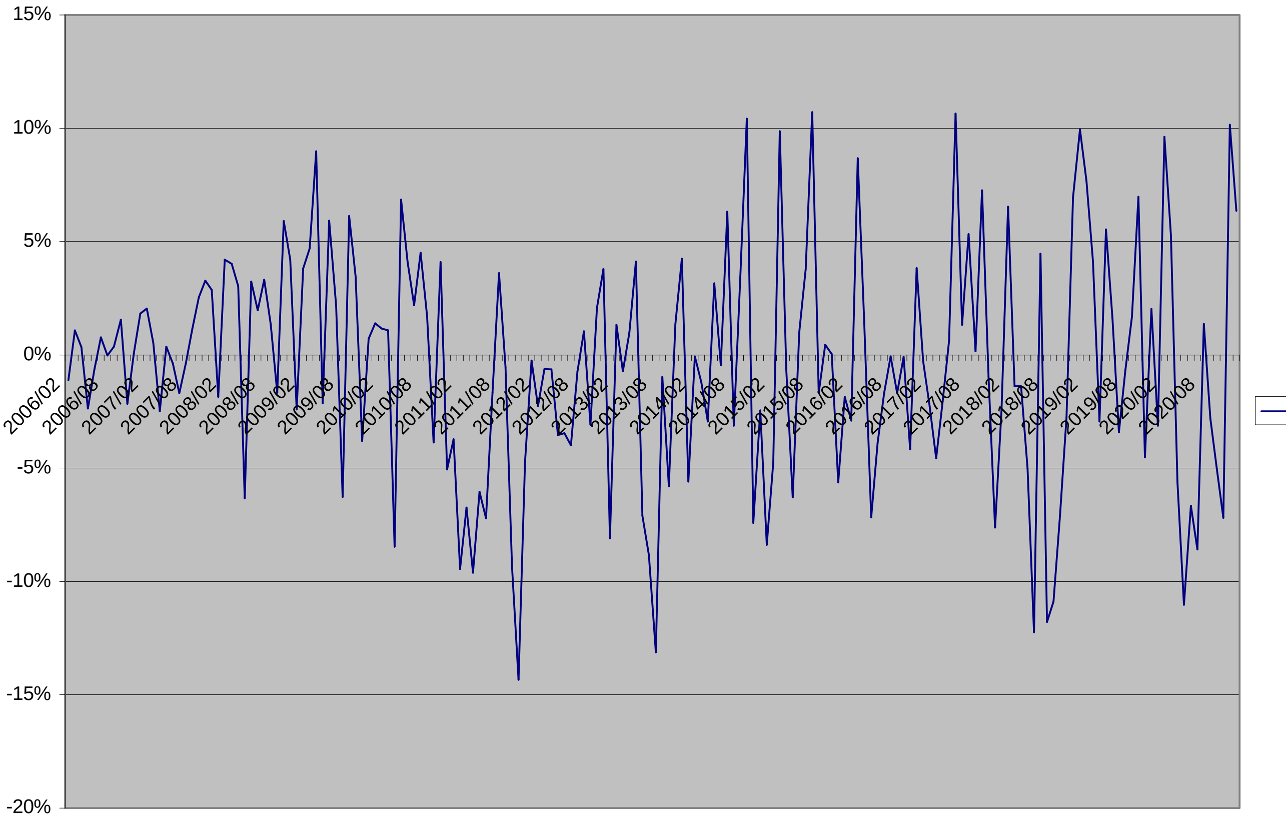
Investment (EU ETS - Case 2)

Investment (GW)	CCGT-I	NPP-E	SOLAR-E	WIND - E	SCHP-E	CCGT-E	GT-E
2006-2007	0.00	1.22	4.68	8.81	2.00	5.59	2.83
2007-2008	0.00	0.00	0.00	21.38	0.00	0.00	0.00
2010-2011	1.25	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.25	1.22	4.68	30.18	2.00	5.59	2.83

Investment (EU ETS - Case 3)



Demand variation (quotas/benchmark) - cas 1



Total demand variation (quotas/ benchmark) - cas 1

CO2 emission (Gt)	Incumbent	Entrant	Total
2006-2007	0.09	0.02	0.11
2007-2008	0.09	0.02	0.10
2008-2009	9.13	15.87	25.00
2009-2010	0.00	25.00	25.00
2010-2011	9.13	15.87	25.00
2011-2012	0.00	25.00	25.00
2012-2013	0.00	25.00	25.00
2013-2014	11.58	13.42	25.00
2014-2015	0.00	25.00	25.00
2015-2016	0.63	24.37	25.00
2016-2017	0.63	24.37	25.00
2017-2018	0.63	24.37	25.00
2018-2019	0.63	24.37	25.00
2019-2020	0.32	24.68	25.00
2020-2021	0.63	21.83	22.46
Total	33.48	289.19	322.67

CO2 emissions according actors - case 1