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Renewables, Allowances Markets, and Capacity Expansion in Energy-Only Markets

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Abstract

We investigate the combined effect of an Emissions Trading System (ETS) and renewable energy sources on electricity generation investments in energy-only markets. We study the long-term capacity expansion decision in fossil fuel and renewable technologies when electricity demand is uncertain. We model a relevant tradeoff: a higher share of renewable production can be priced at the higher marginal cost of fossil fuel production, yet the likelihood of achieving higher profits is reduced because more electricity demand is met by cheaper renewable production. We illustrate our theoretical results comparing the optimal solutions under business-as-usual and various ETSs and renewables scenarios. This illustration shows under which limiting market settings a monopolist prefers withholding investments in renewable energy sources, highlighting the potential distortionary effect introduced via the ETS. Our conclusions remain unaltered under varying key modelling assumptions.

JEL: D43, L51, L94, Q48.

Keywords: Emissions Trading System; Energy-Mix; Pass-Through; Electricity Markets; Electricity Sector.

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1 Introduction

The past five years have witnessed a systematic decrease in the electricity sector operational profitability and a consequent decline in capacity investments in market-based systems (*Financial Times*, 2015; *The Economist*, 2015). Overcapacity of fossil fuel electricity generation and a larger share of renewable electricity generation¹ are among the main causes (Koch et al., 2014). Particularly in Europe, renewables² have not just put pressure on margins; they have also transformed the established business model of utilities (*The Economist*, 2013). Electricity from renewables has favorable access to the grid, squeezing the earnings of polluting generation. However, this preferential grid access is not solely the result of policies favouring renewables. It is also logical in electricity markets that operate based on the merit order: since the marginal cost of renewables is virtually zero, grids would take their electricity first anyway. In this paper, we explore some of the implications of this changing business model on the long-term capacity expansion decision of the electricity sector when polluting emissions from fossil fuel generation are regulated by an Emissions Trading System (ETS).

The long-term capacity expansion decision in the electricity sector (the so-called energy-mix decision) is key to the goal of a low-carbon economy. Electricity and heat generated by fuel combustion are responsible for approximately 42% of CO₂ emissions worldwide (International Energy Agency, 2017). Consequently, electricity sectors in many countries have been brought under ETS regulations. This is the case in Europe (EU ETS, European Union Emissions Trading System), the US (Californian cap-and-trade program), South Korea (KETS, Korea Emissions Trading Scheme), and China (pilot ETS in the Province

¹We will write fossil fuel generation as a shorthand throughout the paper. Besides, conventional generation and polluting generation will be used as synonyms. Also, we will write renewable generation as a shorthand throughout the paper. And non-conventional generation and green generation will be used as synonyms.

²Renewables will be used as a shorthand for renewable energy sources throughout the paper.

of Guangdong). In particular, the EU ETS is a cornerstone of the European policy to reduce CO₂ (80% by 2050, see European Commission, 2011) and, ultimately, to combat climate change. Research studying the energy-mix decision in the presence of an ETS is slowly emerging and has primarily focused on the short-term effects, e.g. the fuel switching effect (see Kirat and Ahamada, 2011, and references therein). We contribute to this literature by investigating the impact of emission caps on long-term capacity expansion decisions in energy-only markets. The policy implications of our work directly speak to the debate about the role of capacity markets and equivalent administrative interventions.

Central to this problem is the tradeoff on profits associated with increased renewable generation. Investments in renewables drive fossil fuel plants out of the market, resulting in costly idle capacity. This is the so-called merit order effect. Yet, investments in renewables generate higher rents because green generation can be sold at the marginal cost of fossil fuel plants. Which of the two effects dominates depends on which generation is at the margin. This means that electricity producers might have an incentive to withhold investments in renewable capacity. The market structure and the regulatory framework are crucial for determining the extent to which the electricity sector withholds capacity investments. In recent contributions, Murphy and Smeers (2005), Zöttl (2011), Murphy and Smeers (2012), and Grimm and Zoettl (2013) investigate capacity investment incentives when markets are not competitive. These authors show that withholding capacity investments can in fact increase profits, ultimately hampering adequate capacity installation. These papers develop their analysis either abstracting from the presence of emission regulations, or treating emission regulations in the form of an ETS as given. In particular, the price of allowances associated with an ETS is either omitted or treated as a given parameter.³ However, in the energy-mix decision, which is long-term, the price of allowances depends

³We will write allowances as a shorthand for emission allowances associated with an ETS throughout the paper.

heavily on the energy-mix itself. Consequently, such a price should be treated (as we do here) as an endogenous variable and should be part of the long-term capacity expansion decision.

In this paper, we contribute to this literature by investigating how an ETS affects the profits resulting from long-term capacity expansion decisions. This line of analysis adds to the growing literature that stresses the need to account for the full effects of coexisting emission constraints and renewable energy source policies due to the sometimes conflicting incentives of the stakeholders involved.⁴ Acknowledging these effects is critically important for the design of long-term electricity markets since conflicting incentives can often lead to suboptimal outcomes, or even outcomes in contrast to the compelling goals of the environmental policy. For example, Acemoglu et al. (2017) investigates the incentives of fossil fuel energy producers to increase the share of renewables in their energy portfolios. They demonstrate, in an oligopolistic setup, that the installation of renewable capacity can actually decrease net welfare as a result of reductions in energy production when the supply of renewables is high. We also assume a cooperative oligopoly in capacity investments and adopt an equivalent monopolist set up to examine the interplay between incentives to the electricity sector and prices of electricity and allowances.

The monopolist set up allows us to transparently investigate the potential distortion of market prices in energy-only markets via an ETS.⁵ We do not undertake a full-fledged welfare analysis. Rather, we focus our attention on key socio-economic variables, such as the percentages of renewable generation and fossil fuel generation, the level of electricity prices, and the level of profits accruing to the electricity sector, and compare the solutions

⁴Previous analyses have highlighted the potential detrimental impacts of overlapping renewable energy source policies (reviewed by Fischer and Preonas, 2010), including overall declines in cost-efficiency (Böhringer et al., 2008, 2009) and increases in the consumer electricity price (Böhringer and Behrens, 2015). We add to this literature too.

⁵In energy-only markets, electricity producers are paid for the amount of electricity produced, but they are not compensated for keeping capacity available.

under a Business-As-Usual (BAU) scenario and under an ETS scenario.

Our theoretical results show that the monopolist has an incentive to drive the allowances price to the level of the penalty for non-compliance.⁶ This occurs when allowances to cover emissions associated to fossil fuel generation are insufficient. Thus, the decarbonizing potential of the ETS is weakened. We illustrate this result with a quantitative example and present under which limiting market setting renewable capacity is increased. These results provide insights into the observed decline of new investments in renewables in Europe,⁷ where the flagship ETS is entering its fourth (more stringent) Phase and the existing share of renewable capacity is already significant. As such, our analysis also contributes to the current discussion on the reform of energy and environmental policies.

The remainder of the paper is set out as follows. In Section 2, we develop an analytical model of the long-term capacity expansion decision of a monopolist that can supply electricity both from fossil fuel and renewables plants. In Section 3, we solve the long-term capacity expansion problem of the monopolist and describe how the installation of renewable capacity impacts on profits. In Section 4, we illustrate the combined effects of increased renewables penetration and more stringent emission regulations by numerically solving the long-term capacity expansion problem under two scenarios and for three distinct market settings. Section 5 discusses the implications of relaxing the key model assumptions of monopoly and perfectly inelastic electricity demand, as well as relaxing various

⁶The results in Hintermann (2017) are compatible with our theory. In Hintermann (2017), the monopolist under-abates emissions in order to drive up the allowances price. The logic in our model and in that of Hintermann is the same: driving up the allowances price increases the costs of marginal plants, but it also increases infra-marginal profits. Previous arguments along similar lines are discussed in Misiolek and Elder (1989) and, more recently, in Hintermann (2011). The assertion that regulated electricity firms benefit from a higher allowances price has been empirically verified (e.g. see Oberndorfer, 2009; Hirth and Ueckerdt, 2013).

⁷New investments in renewables in Europe peaked in 2011 at \$120 billion and have fallen ever since; new capacity investments in 2015 and 2016 were less than half that maximum at \$59.8 billion (see Frankfurt School-UNEP Collaborating Centre for Climate & Sustainable Energy Finance and Bloomberg New Energy Finance, 2017).

modelling choices (adjustments of capacity expansion; inter-temporal allowance banking; and regulatory adjustments). Section 6 concludes. The Appendix reports several details of the solution to the long-term capacity expansion problem, with a particular focus on a sensitivity analysis with respect to two key model parameters.

2 Model

2.1 Market structure

We consider an electricity sector endowed with polluting and green technologies. We also assume that plants are owned by few large electricity producers, so that the electricity sector can be seen as an oligopoly. Around the world, electricity markets remain highly concentrated, with few major national producers controlling a substantial share of the domestic capacity. For example, according to EIA,⁸ the first 108 US electricity producers (over a total of 4,138) accounted for 60% of the national nominal capacity in 2017. In addition, in the 9 largest European national markets⁹, approximately 3,208 electricity producers covered 95% of net domestic demand in 2016, but only 30 of them had a domestic market share larger than 5%.¹⁰ Yet, cross-border electricity transmissions are increasing, contributing to the development of a more competitive electricity market.

In order to simplify our analytic treatment and concentrate on the price distortion of an ETS, we assume that electricity production is sold through the standard system of uniform auction. This price fixing mechanism and the presence of a share of smaller competitive electricity producers can exert a significant pressure on major producers to make them bid at the marginal cost (as if they were acting under perfect competition).

⁸see <https://www.eia.gov/electricity/data/eia860/>.

⁹Austria, Belgium, Denmark, France, Germany (with data for 2012), Italy, Netherlands, Spain, UK.

¹⁰see Eurostat at https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_market_indicators#Electricity_markets_-_generation_and_installed_capacity.

Notice that assuming collusion on the electricity market by producers that, consequently, would charge a constant markup on top of their marginal costs would leave our main conclusions unaffected. Indeed, such a markup would not eliminate the economic incentive to profit from exceeding the emissions cap. This will be discussed in more detail later. Moreover, we assume that electricity producers act cooperatively to decide the energy-mix. By adopting a cooperative oligopoly (or, equivalently, a monopolist set up), we obtain a tractable model of the aggregated energy-mix decision. This allows us to obtain an analytic solution of the problem and to transparently describe the distortion mechanism that an ETS can spawn. Besides, the adoption of a cooperative oligopoly is not an outlandish assumption given the anecdotal evidence of market concentration.¹¹

In the following, we will use interchangeably the terms monopolist and electricity sector.

2.2 Model settings

The focus of the present paper is on the long-term impact of an ETS on the installation of green technology capacity. As such, we abstract from short-term effects of an ETS, e.g. fuel switching, and consider a single period model. The implications of a two-period extension of our model are qualitatively discussed in Section 5.

Given period $[0, T]$, we distinguish the time of decision $t = 0$, the time when key information is revealed (and uncertainty is resolved) $t = 0^+$, and the generation period $[0^+, T]$, where no news are announced and no decisions take place. The capacity available at time $t = 0$ is Q_c and Q_{nc} , for conventional and non-conventional technologies respectively (capacity will be expressed as the total *MWh* that can be potentially generated during period $[0^+, T]$). At time $t = 0$, the electricity sector decides on the long-term expansion of its capacity, and, in particular, the desired level of installation for conventional, ΔQ_c , and

¹¹In Europe, RWE takeover of EON electricity generation assets increased concentration on generation.

non-conventional, ΔQ_{nc} , capacity. Negative levels of installation mean that the respective technology is disconnected/dismantled and will no longer generate electricity. For simplicity, we assume that disconnecting a plant from the grid or dismantling a plant can be done at insignificant cost. We neglect implementation time, so the new capacities for both technologies are assumed to be immediately available and operational, and assume that no additional capacity is added during period $[0^+, T]$. The long-term capacity expansion decision is risky since electricity demand during period $[0^+, T]$ (hereafter D) is uncertain at time $t = 0$. D is assumed to be revealed at time $t = 0^+$. In particular, D is normally distributed with expected value μ and standard deviation σ .¹² In order to simplify the analytical treatment, we also assume that D is price inelastic during period $[0^+, T]$. Our results remain largely unaltered when considering an elastic electricity demand. We present this case later in Section 5 and discuss its implications.

Two spot markets are relevant in this model: the electricity market and the allowances market. In the first market, electricity is asked and offered, and p is the resulting equilibrium price of 1 *MWh* of electricity. This price is set at time $t = 0$ and depends on the uncertain level of D at that time. p remains constant during period $[0^+, T]$. In line with the literature and the common practice in electricity markets, electricity is traded through a uniform auction system. Under this setting, as it is well known, every agent has an incentive to offer all its capacity at the marginal cost, “as if” agents were perfect competitors (i.e. independently of the real level of competition in the market). In the second market, which is a feature of an ETS, allowances can be traded. One allowance entitles a producer to emit 1 tonne of carbon dioxide (CO_2), the main greenhouse gas, or

¹²The uncertainty of the model is handled with the triple $(\Omega, \mathcal{A}, \mathbb{P})$, where Ω is the event space, \mathcal{A} is the σ -algebra of subsets of Ω , whereas \mathbb{P} is the probability corresponding to the normal distribution of D . Besides, D has density function on the set of real numbers given by $f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{\mu-x}{\sigma}\right)^2}$. Even though a non-negative distribution (e.g. lognormal) would be more appropriate for D , normality is still a reasonable assumption as long as μ is significantly larger than σ , as, indeed, it is the case in this analysis.

the equivalent amount of two other powerful greenhouse gases, nitrous oxide (N_2O) and perfluorocarbons (PFCs). In the following, we will not distinguish among these greenhouse gases, and we will label them as CO_2e . The price of an allowance is p_a and it is paid upfront at time $t = 0$ when allowances are auctioned off (and D is uncertain).

The electricity sector faces two distinct generation costs: direct production costs and the cost of allowances (environmental cost). Let $c_{v,nc}$ and $c_{v,c}$ represent the costs of generating 1 *MWh* of electricity using non-conventional and conventional plants, respectively. The regulatory authority determines the number of allowances, C . Thus, if a conventional plant emits m tonnes of CO_2e to generate of 1 *MWh* of electricity, the (unit) cost of allowances is $c_a = mp_a$ per each *MWh*. Furthermore, $H = C/m$ *MWh* corresponds to the total conventional generation covered by allowances. In other words, conventional plants can produce a maximum of H *MWh* of electricity - covered by C allowances - to remain compliant with the emissions cap. In case of non-compliance, producers must pay the penalty f for each tonne of CO_2e beyond C . We define an ETS as being effective if the total emissions of CO_2e from fossil fuel generation do not exceed C . At time $t = 0$, the demand of allowances by the electricity sector is $m \times \min(H; Q_c + \Delta Q_c)$. By arbitrage arguments (e.g. see Carmona et al., 2010; Chesney and Taschini, 2012), c_a , which is the cost of allowances at time $t = 0$, is determined by the probability that during period $[0^+, T]$ conventional plants will be required to produce more electricity than can be covered by allowances.

Finally, since the aim of the paper is to study the long-term impact of an ETS on the energy-mix decision, we consider the case where period $[0, T]$ covers the entire lifetime of new capacity investments. Also, we assume that (i) the ETS ends at T and (ii) the amount of allowances needed by non-electricity sectors just equals the amount of allowances allocated to them. Thus, we abstract from (i) banking and borrowing of allowances and (ii) trading between the electricity and non-electricity sectors. We consider the effect of

banking in Section 5.

2.3 Energy-only markets and the merit order curve

In an energy-only market, prices are determined by the interaction between demand and supply, and supply is determined by the merit order. The merit order is a ranking of electricity generation, based on ascending marginal costs. In practice, non-conventional plants (such as wind, solar, and nuclear plants) have extremely low marginal costs, so electricity from these plants is usually cheaper than that generated by conventional plants using coal or natural gas as fuel. This means that, when demand is low and fully satisfied by non-conventional technologies, electricity is priced at the marginal cost of non-conventional plants. Electricity producers will turn on conventional plants only if the supply of non-conventional plants does not fully satisfy demand. In this case, electricity is priced at the marginal cost of conventional production.

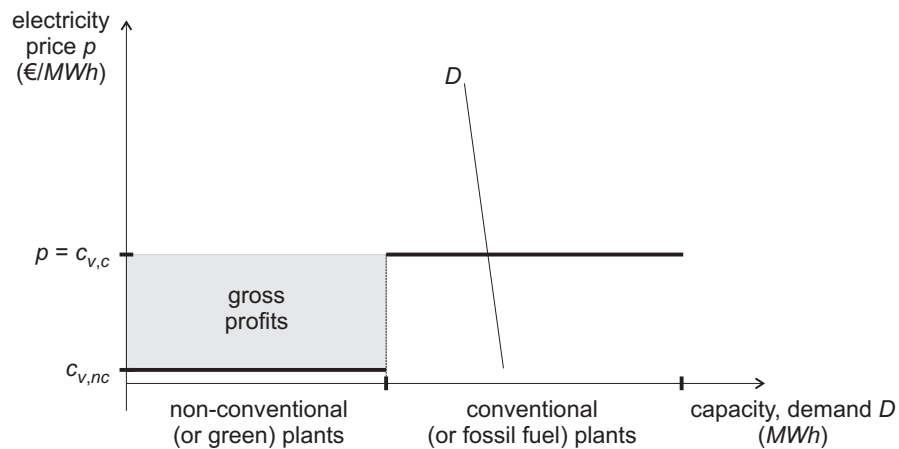


Figure 1: The classic merit order curve ranks electricity generation based on ascending marginal costs. The curve is a step-function with two values: the near-zero cost of non-conventional generation and the higher cost of conventional generation. Electricity from non-conventional plants is used first to meet demand, followed by electricity from conventional plants.

Hence, the merit order is a step-function composed of different marginal costs, each cost depending on one among many types of energy sources. Our analysis uses a simplified two-step merit order curve consisting of only two types of energy sources, non-conventional and conventional (see Figure 1). Since this approach groups all polluting technologies in a single class, it is not cater for the modelling of short-term fuel switching effects of allowances markets. Nevertheless, given our interest on the long-term impact of an ETS to drive the decarbonization process of an economy, the aggregate capacity of green technologies versus that of conventional technologies are the fundamental variables to be modelled here.

Figure 1 clearly shows the peak-load pricing effect: when electricity demand is high, non-conventional production is priced at the higher marginal cost of conventional plants.

Profit opportunities change introducing an ETS. Morthorst (2001), Böhringer and Rosendhal (2011), and, more recently, Böhringer and Behrens (2015) investigate how emission constraints change the electricity market outcome of support schemes for non-conventional production. We complement this stream of works by deriving analytical dependencies between the long-term capacity expansion decision and prices of electricity and allowances. In the presence of an ETS, producers need to buy m allowances for every MWh of conventional generation (recall that m is the number of tonnes of CO_2e emitted from the generation of 1 MWh of electricity). Therefore, the cost of allowances must be included into the direct costs. The impact of the cost of allowances on electricity prices is modelled here by a pass-through coefficient $\beta \in [0, 1]$, which describes the ability of the electricity sector to transfer a fraction of the cost of allowances to consumers.

If D is large enough to require the contribution of conventional plants, the price of electricity will be equal to

$$p = c_{v,c} + \beta m p_a,$$

where p_a is the market price of the allowance to emit 1 tonne of CO_2e . At time $t = 0$, p_a is

calculated as a risk-neutral expectation of its final price. We provide the expression of such a price in Eq. (2). The value of p_a during period $[0^+, T]$ is, however, much simpler than that of p_a at time $t = 0$. Since D is assumed to be perfectly known at time $t = 0^+$, by simple arbitrage arguments, it is immediate to see that the market price of allowances becomes either 0 or $f > 0$ and remains constant during period $[0^+, T]$. Indeed, as soon as D is known, it is immediate to check if the generation required from polluting plants exceeds H (i.e. the generation threshold that can be covered by existing allowances). In case of an excess of emissions, producers must pay the penalty mf for every MWh of uncovered conventional generation (i.e. generation beyond H , see Figure 2), whereas allowances become worthless in the opposite case. The pass-through coefficient β has been the subject of some recent studies. Using different econometric techniques, Sijm et al. (2006), Bunn and Fezzi (2007), Zachmann and von Hirschhausen (2008), Fabra and Reguant (2014), Wild et al. (2015), and Hintermann (2016) find empirical evidence of pass-through of allowance costs in numerous electricity markets. This literature shows that there is potential for high levels of pass-through of allowance costs.¹³ However, it does not provide unambiguous figures. In the Appendix, we present a sensitivity analysis, where we investigate the influence of different levels of pass-through of allowance costs on the long-term capacity expansion decision.

If, at time $t = 0$, D is expected to be particularly high, so that conventional generation will exceed H , we can assume that p_a , i.e. the risk-neutral expectation in Eq. (2), is equal to f . Depending on the pass-through coefficient β , the electricity market is cleared at the marginal cost of uncovered conventional plants:

$$p = c_{v,c} + \beta mf.$$

As Figure 2 shows, this price generates large profit opportunities for both technologies.

¹³All these studies do not reject the null hypothesis of complete pass-through.

Recall that H corresponds to the maximum conventional generation that can be covered by allowances.

Let us consider the possible values of electricity and allowance prices during period $[0^+, T]$, i.e. when electricity demand is known. In event A_1 , electricity demand is entirely satisfied by non-conventional capacity, $D \leq Q_{nc} + \Delta Q_{nc}$, so the allowances demand falls to zero and p_a must be zero. In this case, the electricity price p is only driven by the marginal cost of green technologies. Therefore,¹⁴

$$p(A_1) = c_{v,nc} \quad \text{and} \quad p_a(A_1) = 0.$$

In event A_2 , electricity demand exceeds non-conventional capacity. However, in this case, all emissions are covered by allowances: $Q_{nc} + \Delta Q_{nc} < D < Q_{nc} + \Delta Q_{nc} + H$. Therefore, the conditional price of allowances is zero and the electricity price coincides with the marginal cost of polluting technologies:¹⁵

$$p(A_2) = c_{v,c} \quad \text{and} \quad p_a(A_2) = 0.$$

In event A_3 , the electricity demand is so high that D exceeds both non-conventional and covered conventional capacities: $D > Q_{nc} + \Delta Q_{nc} + H$. Technically, total emissions of CO₂e from fossil fuel generation exceed C , and the ETS is environmentally ineffective. Hence, producers must pay the penalty for each uncovered tonne of CO₂e and the conditional price of allowances reaches f . Therefore,¹⁶

$$p(A_3) = c_{v,c} + \beta m f \quad \text{and} \quad p_a(A_3) = f.$$

¹⁴With a small abuse of notation, we write $p(A_1)$ to mean $p(\omega)$ for all $\omega \in A_1$. The same simplification applies to $p_a(A_1)$.

¹⁵See footnote 14, with A_2 in place of A_1 .

¹⁶See footnote 14, with A_3 instead of A_1 .

Table 1 synthesizes the values of some variables depending on a combination of technical conditions and chance. The technical conditions depend on H and the energy-mix decision. The chance, events A_1 , A_2 , and A_3 , consists of realized levels of electricity demand.

Table 1: Electricity and allowance prices for $t \in [0^+, T]$, as identified by a combination of technical conditions and realized levels of electricity demand. The technical conditions depend on H and the energy-mix decision, i.e. $Q_{nc} + \Delta Q_{nc}$ and $Q_c + \Delta Q_c$.

Technical condition	Event	Allowances price, p_a	Cost of allowances, c_a	Electricity price, p
$Q_{nc} + \Delta Q_{nc} > 0$	A_1	0	0	$c_{v,nc}$
$Q_c + \Delta Q_c > 0$	A_2	0	0	$c_{v,c}$
$Q_c + \Delta Q_c > H$	A_3	f	mf	$c_{v,c} + \beta mf$

We assume throughout the paper that the technical conditions are satisfied. In particular, they will be included into the constraints of the optimization problem developed here.

2.5 Electricity and allowance prices

At time $t = 0$, the electricity price p is calculated as an expectation. We denote it as p_0 :

$$p_0 = p(A_1) \mathbb{P}(A_1) + p(A_2) \mathbb{P}(A_2) + p(A_3) \mathbb{P}(A_3),$$

where $p(A_i)$, $i = 1, 2, 3$, is the price of electricity during period $[0^+, T]$ for the three events A_1 , A_2 , and A_3 . Recalling that D is normally distributed with expected value μ and standard deviation σ , the expression of the electricity price at time $t = 0$ can be analytically

written as

$$\begin{aligned}
p_0 = & \underbrace{c_{v,nc}}_{p(A_1)} \underbrace{\left(\frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{Q_{nc}+\Delta Q_{nc}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \right)}_{\mathbb{P}(A_1)} \\
& + \underbrace{c_{v,c}}_{p(A_2)} \underbrace{\left(\frac{1}{\sigma\sqrt{2\pi}} \int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \right)}_{\mathbb{P}(A_2)} \\
& + \underbrace{(c_{v,c} + \beta m f)}_{p(A_3)} \underbrace{\left(1 - \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \right)}_{\mathbb{P}(A_3)}.
\end{aligned} \tag{1}$$

Recall that allowances have a positive price only in event A_3 (non-compliance event). By arbitrage arguments (e.g. see Carmona et al., 2008) and assuming a risk-neutral electricity sector, a null interest rate, and a normally distributed electricity demand, it is possible to show that the price of allowances at time $t = 0$, which we denote as $p_{a,0}$, is equal to the product between the penalty for non-compliance f and the probability of event A_3 :

$$p_{a,0} = f \left(\mathbb{E}(1_{(H,\infty)}(D - Q_{nc} - \Delta Q_{nc})) \right) = f \left(1 - \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \right), \tag{2}$$

where $1_{(H,\infty)}(D - Q_{nc} - \Delta Q_{nc})$ is the indicator function that is equal to one if electricity demand is satisfied by uncovered conventional generation.

2.6 Gross and net profits of the electricity sector

In this section, we analyse the profits accruing to the electricity sector. To develop an economic intuition for the results of the model, we analyse the gross profits accruing to the electricity sector (i.e. total revenues less direct costs incurred to generate and sell electricity). Gross profits can be more directly linked to the variables discussed so far, and can be represented as areas of regions under the merit order curves presented in the

previous sections (see Figures 1 and 2). Later on, we turn to the analysis of net profits, including fixed costs.

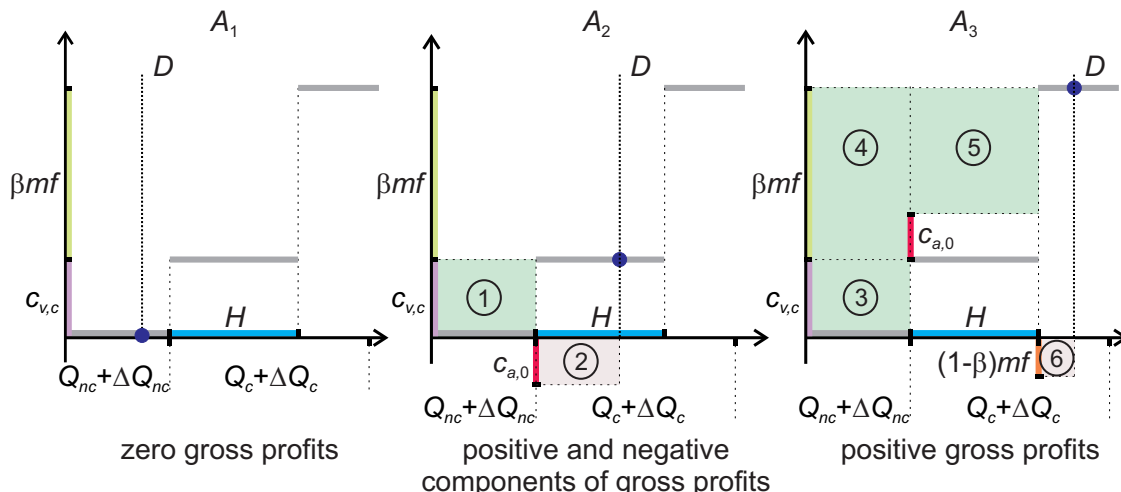


Figure 3: Gross profits, in € per MWh , depending on events A_i , $i = 1, 2, 3$, of the sample space Ω (capacity, “ Q ” and “ ΔQ ”, and electricity demand, D , are given in MWh). In particular, $c_{a,0} = mp_{a,0}$ and $p_{a,0}$ is defined in Eq. (2).

The areas of the shaded regions in Figure 3 illustrate the (conditional) gross profits associated with the three events A_1 , A_2 , and A_3 discussed in Section 2.4. In this figure, variable costs of green technologies are set equal to zero ($c_{v,nc} = 0$). This figure highlights some aspects relevant to our discussion. First, apart from event A_1 , where gross profits are zero, the size of gross profits directly depends on the decision variables ΔQ_{nc} and ΔQ_c . Second, gross profits do not proportionally increase with electricity demand. Rather, they increase by steps, as soon as D exceeds the thresholds defining the three events. Nevertheless, in case of events A_2 and A_3 , we observe a negative component (areas of regions 2 and 6, respectively), proportionally changing with electricity demand. More precisely, the area of region 2 accounts for the initial cost of allowances used to cover the generation required by D . As such, these are direct generation costs. Unused allowances, on the

contrary, can be treated as sunk costs. Because the summation of the two cost components is constant, the initial cost of allowances does not generally depend on electricity demand, as it will be made clear in the expression of expected profits accrued to the electricity sector (see Eq. (8)). Third, in case of event A_3 , a significant share of gross positive profits from non-conventional and conventional generation is represented by the areas of regions 4 and 5. This sizeable amount makes event A_3 highly desirable. Concurrently, when event A_3 is realized, there is a negligible negative component too, area of region 6. This corresponds to the penalty paid for the excess generation (beyond H). Both the area of region 5 is sizeably positive and that of region 6 is negligibly negative for empirically relevant values of β . As it will be clear in Section 3, the crux of the energy-mix decision is to increase the likelihood of event A_3 .

We now turn to net profits, which are obtained by subtracting fixed costs from gross profits. Fixed costs contain different components, mainly labour, maintenance, and investment, and they can be linked to the size of plants. We define fixed costs as

$$FC = FC(c_{f,c}, c_{f,nc}) = c_{f,c}(Q_c + \Delta Q_c) + c_{f,nc}(Q_{nc} + \Delta Q_{nc}) + \alpha(Q_{nc} + \Delta Q_{nc})^2,$$

where $c_{f,nc}$ and $c_{f,c}$ are the unit investment costs (per MWh) of non-conventional and conventional plants, respectively. Notice that we consider a linear function of costs for conventional plants and a quadratic function of non-conventional costs. We motivate this choice with the fact that, for non-conventional plants, the best locations are used first, with the consequence that the capacity investments required to obtain 1 MWh should increase more than linearly as the total capacity in place gets larger.¹⁷

Given these costs and assuming the technical conditions of Table 1, we examine the net

¹⁷The constant returns assumption for conventional plants follows from the fact that conventional technologies are easily scalable and, consequently, do not generate a scarcity rent. The decreasing returns assumption for non-conventional plants follows from the fact that the best production sites are used first and that further non-conventional development implies investing in less and less productive sites.

profits in the electricity sector under the three events A_1 , A_2 , and A_3 . In event A_1 , electricity demand is entirely satisfied by non-conventional capacity, $D \leq Q_{nc} + \Delta Q_{nc}$. Gross profits are zero because the price of electricity is equal to the variable cost of generation, which is zero by assumption (left panel of Figure 3). In this case, the conditional net profits G are negative because of fixed costs and the cost of allowances:¹⁸

$$G(A_1) = -FC - c_{a,0}H. \quad (3)$$

In event A_2 , electricity demand requires the contribution of conventional capacity (in addition to non-conventional capacity), $Q_{nc} + \Delta Q_{nc} < D < Q_{nc} + \Delta Q_{nc} + H$, but all emissions from conventional generation are covered by allowances. In this case, non-conventional generation is sold at a price equal to the cost of conventional generation. The conditional net profits G are equal to¹⁹

$$G(A_2) = -FC - c_{a,0}H + (c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}). \quad (4)$$

In event A_3 , $D > Q_{nc} + \Delta Q_{nc} + H$. Conventional plants generate electricity in excess of the threshold H . Therefore, the marginal cost of electricity must include both the cost of conventional generation ($c_{v,c}$) and the penalty per unit (MWh) of emission eventually reduced by the pass-through coefficient (βmf). The conditional net profits G are equal

¹⁸With a small abuse of notation, we write $G(A_1)$ to mean $G(\omega)$ for all $\omega \in A_1$.

¹⁹See footnote 18, with A_2 in place of A_1 .

to²⁰

$$\begin{aligned}
G(A_3) = & -FC + (\beta mf - c_{a,0}) H \\
& + (\beta - 1) mf (D - Q_{nc} - \Delta Q_{nc} - H) \\
& + (\beta mf + c_{v,c} - c_{v,nc}) (Q_{nc} + \Delta Q_{nc}).
\end{aligned} \tag{5}$$

Depending on the levels of the pass-through coefficient, it is not always preferable to expand non-conventional capacity. We discuss this later in footnote 21.

Two observations are in order. First, the application of a constant markup on top of marginal costs leaves our conclusions unaltered. Such a markup can only change the height of the shaded regions in Figure 3, leaving the energy-mix decision problem – namely, the control of the horizontal dimension of the shaded regions – practically unaffected. Second, we do not consider the case of $D = Q_{nc} + \Delta Q_{nc} + H$, i.e. the case where D exactly exhausts allowances. This is an unlikely event – the probability of this event is zero if D is assumed to be an absolutely continuous random variable. Also, the price of allowances would not be uniquely defined in such a case: indeed, it could take any value between 0 and f .

2.7 Operational and allowance components of profits

For each of the three events, we can separate gross profits into two components: an *operational component* and an *allowance component*. The operational component is determined by the sale of non-conventional electricity at the marginal cost of conventional generation. The allowance component comes from including into the price of electricity the cost of allowances needed to cover emissions from conventional generation.

Assuming the technical conditions of Table 1 and conditioning on the corresponding event, we have the following results. In event A_1 , there is neither operational component

²⁰See footnote 18, with A_3 instead of A_1 .

nor allowance component. In event A_2 , the operational component is positive and the allowance component is negative:

$$\begin{aligned}
G(A_2) + FC &+ \underbrace{c_{a,0}(H - D + Q_{nc} + \Delta Q_{nc})}_{\text{sunk cost for unused allowances}} \tag{6} \\
&= \underbrace{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}_{\text{operational component}} - \underbrace{c_{a,0}(D - Q_{nc} - \Delta Q_{nc})}_{\text{allowance component}}.
\end{aligned}$$

The allowance component is negative because the conventional generation “consumes” allowances that costed $c_{a,0}$ per MWh . It corresponds to the area of region 2 in the central panel of Figure 3. Unused allowances, on the contrary, are treated as sunk costs. In event A_3 , the operational component is positive and the allowance component, depending on the levels of the pass-through coefficient β , can be positive or negative:

$$\begin{aligned}
G(A_3) + FC &= (\beta mf - c_{a,0})H + (\beta mf + c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}) \tag{7} \\
&- (1 - \beta)mf(D - Q_{nc} - \Delta Q_{nc} - H) \\
&= \underbrace{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}_{\text{operational component}} - \underbrace{(1 - \beta)mf(D - Q_{nc} - \Delta Q_{nc} - H)}_{\text{allowance component}} \\
&+ \underbrace{\beta mf(Q_{nc} + \Delta Q_{nc} + H) - c_{a,0}H}_{\text{allowance component}}.
\end{aligned}$$

Notice that only small values of β generate a negative allowance component.²¹ In the

²¹We can identify the threshold value of β associated with a null allowance component for $G(A_3)$ in Eq. (7). Such a null component is equivalent to the areas of regions 4, 5, and 6 in Figure 3 summing up to 0. Let us call this value $\bar{\beta}$. Adopting values of β lower than $\bar{\beta}$ causes the area of region 6 to prevail with respect to the areas of regions 4 and 5, therefore making the allowance component negative. Since the allowance component depends on the random variable D , we perform the calculation of $\bar{\beta}$ on the expected allowance component of event A_3 , i.e. the expression of the allowance component in Eq. (7) multiplied by the probability of event A_3 . After some rearrangement, $\bar{\beta}$ is such that

$$(- (1 - \bar{\beta})mf(D - Q_{nc} - \Delta Q_{nc} - H) + \bar{\beta}mf(Q_{nc} + \Delta Q_{nc} + H) - c_{a,0}H) \times \mathbb{P}(A_3) = 0.$$

Given the market settings of Section 4.1 and the capacity investment decisions under the ETS scenario of Section 4.2 (see, in particular, Table 4), the values of $\bar{\beta}$ are 0.04, 0.40, 0.42, and 0.28, for the low RES

Appendix, we present a sensitivity analysis, where we examine the influence of the level of β on the long-term capacity expansion decision.

3 Long-term capacity expansion problem

The long-term capacity expansion problem is solved at time $t = 0$, i.e. when D is unknown. We consider the case where the monopolist maximizes expected profits under the capacity expansion constraints previously discussed. Combining Eq. (3), (4), and (5) along with the corresponding probabilities (see Eq. (1)), expected profits are

$$\mathbb{E}(G) = G(A_1)\mathbb{P}(A_1) + G(A_2)\mathbb{P}(A_2) + G(A_3)\mathbb{P}(A_3), \quad (8)$$

and, considering H (i.e. the conventional generation covered by allowances) and S (a minimum level of conventional capacity to guarantee the security of supply), the long-term capacity expansion problem of the monopolist can be stated as²²

$$\begin{aligned} & \max_{\Delta Q_{nc}, \Delta Q_c} \mathbb{E}(G) \\ \text{s.t.} \quad & \Delta Q_{nc} > -Q_{nc} \\ & \Delta Q_c > H - Q_c \\ & \Delta Q_c \geq S - Q_c \end{aligned} \quad (9)$$

The first constraint guarantees that the installed renewable capacity is positive. The second constraint avoids the case where the emissions cap is slack, i.e. the probability of event A_3 is zero. Indeed, if the installed conventional capacity ($Q_c + \Delta Q_c$) happened to be lower than H , event A_3 would never occur. However, as discussed above, it is in the interest of the monopolist that event A_3 occurs. The third constraint guarantees that $Q_c + \Delta Q_c$

(first two values), average RES, and high RES market settings, respectively.

²²The long-term capacity expansion problem can be easily extended in various ways (e.g. presence of budget constraints, risk constraints, etc.). We leave this for future research.

is not lower than the security of supply conventional capacity S . When (i) it is optimal for the monopolist to reduce conventional capacity (which is, indeed, what we show in the Appendix) and (ii) H progressively decreases (as it is expected in a low-carbon economy), then $S > H$ and the third constraint is more stringent than the second one.

We report the analytical solution to this problem in the Appendix. For evaluation purposes, it must be partially numerically calculated. In the next section, we analyse the problem through a quantitative application to three distinct market settings under two scenarios.

Figure 4 shows the three levels of conditional profits (see Eq. (3), (4), and (5)), as well as the corresponding probabilities (see Eq. (1)). The latter are the areas of the three shaded portions of the distribution of D . Also, Figure 4 illustrates the tradeoff faced by the monopolist when expanding non-conventional capacity from Q_{nc} (left panel) to $Q_{nc} + \Delta Q_{nc} > Q_{nc}$ (right panel): a higher share of non-conventional production can be priced at the higher marginal cost of conventional production; yet the likelihood of achieving higher profits is reduced because more electricity demand is met by cheaper non-conventional production. There is empirical evidence about such a tradeoff: Germany has a high share of renewables in its current energy portfolio. In Germany, many electricity producers complain that (relative to other countries) there is a higher chance that demand is completely satisfied by non-conventional capacity (corresponding to A_1), so electricity is priced at the marginal cost of non-conventional plants (actually, the price of electricity has occasionally become even negative).²³ This indicates that German electricity producers have an incentive to keep the expansion of renewables below some optimal threshold.

The decision to expand non-conventional capacity leads to several economic conse-

²³Over the last few years, European wholesale electricity markets have shown a manifold increase of occurrences of negative prices (*The Economist*, 2017). For instance, in 2013, during a period of low demand and high supply of wind and solar energy, the German wholesale electricity prices fell to -100 €/MWh (*The Economist*, 2013).

quences, of opposite signs:

- probability of event A_1 (losses) expands, as there is a higher likelihood that non-conventional generation can fully meet electricity demand. At the same time, the increased fixed costs resulting from the additional non-conventional generation cause higher losses within this region. Letting $\Delta Q_{nc} > 0$ clearly decreases the expectation of these conditional profits;
- probability of event A_2 (profits with only the operational component) shrinks especially if the share of non-conventional capacity is substantial; however, profits within this region ($G(A_2)$) can increase thanks to the additional non-conventional generation being sold at the price of conventional generation. Therefore, the impact of $\Delta Q_{nc} > 0$ is not clear;
- probability of event A_3 (profits with a very high allowance component) shrinks with certainty; however, profits within this region ($G(A_3)$) increase sharply (especially for values of β close to 1) due to: (a) additional non-conventional capacity being sold at a higher unit profit and (b) covered conventional generation also being sold at a profit. However, under particular circumstances (i.e. β very small and, at the same time, D sufficiently high) conditional profits $G(A_3)$ can reduce significantly. Again, the impact of $\Delta Q_{nc} > 0$ is not clear.

In summary, an increase of non-conventional capacity does not have an obvious overall impact on expected profits. Much of this impact depends on the tradeoff between the increase of $G(A_2)$ and $G(A_3)$ and the reduction of $\mathbb{P}(A_2)$ and $\mathbb{P}(A_3)$.

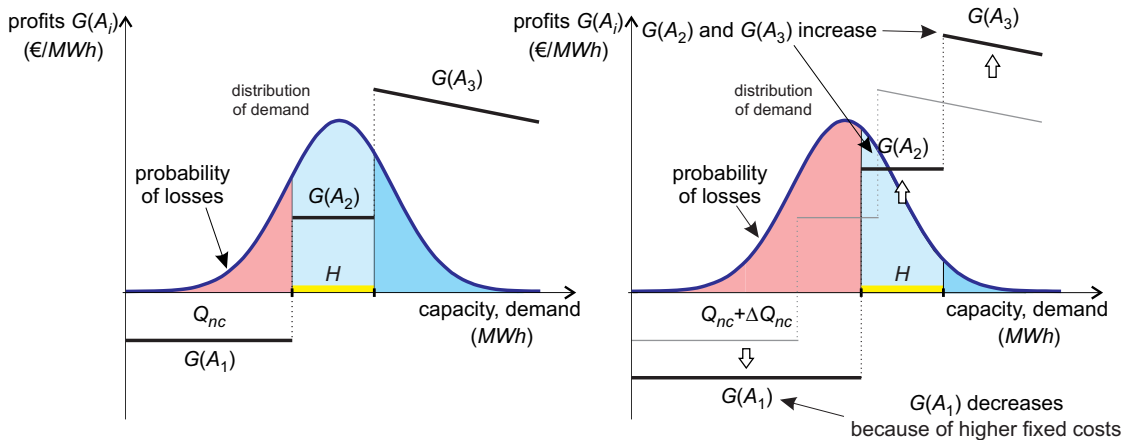


Figure 4: Impact of a positive expansion of green technologies. Increasing the green capacity from Q_{nc} (left panel) to $Q_{nc} + \Delta Q_{nc}$ (right panel) impacts both the levels of profits and the corresponding probabilities. In this example, the probability of the intermediate level of profits ($G(A_2)$) is reduced, that of the high level of profits ($G(A_3)$) becomes very small, while the probability of losses ($G(A_1)$) increases greatly.

4 Numerical illustration

We present an application of the long-term capacity expansion Problem (9) that is numerically solved first in the absence of emission regulations (BAU scenario) and then in the presence of emission regulations (ETS scenario). The BAU scenario is the benchmark. The benchmark solution is obtained by setting the penalty for non-compliance f equal to zero. A null penalty dramatically simplifies the expression of expected profits (Eq. (8)): the price of allowances is zero for $t \in [0, T]$ under all states of nature; consequently, the allowance components in Eq. (6) and (7) vanish and the profits in events A_2 and A_3 become indistinguishable. Notice also that, since the penalty is zero, the level of H becomes irrelevant. The benchmark solution and the ETS solution are compared considering three distinct market settings with various degrees of cap stringency and renewables penetration. This allows us to test the impact of changes in the market setting on the long-term capacity

expansion decision. Below we discuss first the market settings and then the solutions under the BAU scenario and the ETS scenario.

4.1 Market settings

In all market settings, we set S , the minimum level of conventional capacity, equal to the expected value of electricity demand, i.e. 200 MWh . This way, electricity demand can be satisfied, on average, in all settings.

The first market setting (left panel of Figure 5) corresponds to the case where the initial share of renewable capacity is the lowest ($Q_{nc} = 20 MWh$) and the emissions cap is relatively generous ($H = 120 MWh$). We label this market setting as *low RES*. The second market setting, labelled as *average RES* (middle panel of Figure 5), corresponds to the case where the initial share of renewable capacity is larger ($Q_{nc} = 100 MWh$) and the emissions cap is tighter ($H = 100 MWh$) than that of the first setting. Notice that $S > H$ in all three market settings and the security of supply constraint becomes binding. The sum of initial non-conventional capacity and allowances exactly meet the expected value of electricity demand, 200 MWh . Hence, at time $t = 0$, emissions from conventional plants can exceed the cap with a probability of 50% (see the dashed segment with respect to the distribution of D in the middle panel of Figure 5). The last market setting, labelled as *high RES*, corresponds to the case where renewables cover a relatively large amount of electricity demand ($Q_{nc} = 210 MWh$) and the emissions cap is significantly tighter ($H = 20 MWh$). In this last market setting, the initial non-conventional capacity plus the amount of allowances cover electricity demand with a probability of 84% (right panel of Figure 5). The model parameters common to the three distinct market settings are reported in Table 2, whereas the initial capacities of these settings are reported in Table 3 and illustrated in Figure 5.

Table 2: Model parameters common to the three distinct market settings.

Model parameter	Value	Model parameter	Value
Security of supply conventional capacity, S (MWh)	200	$c_{v,c}$ ($\text{€}/MWh$)	60
Expected value of electricity demand, μ (MWh)	200	$c_{v,nc}$ ($\text{€}/MWh$)	0
Standard deviation of electricity demand, σ (MWh)	30	$c_{f,c}$ ($\text{€}/MWh$)	1.5
m (tonnes/ MWh)	1.1	$c_{f,nc}$ ($\text{€}/MWh$)	6
f ($\text{€}/\text{tonne}$)	100	β	1
α	0.01		

Table 3: Initial capacities in the three distinct market settings.

Capacity	Market setting		
	Low RES	Average RES	High RES
Initial conventional capacity, Q_c (MWh)	330	330	330
Initial non-conventional capacity, Q_{nc} (MWh)	20	100	210
Covered conventional capacity, H (MWh)	120	100	20

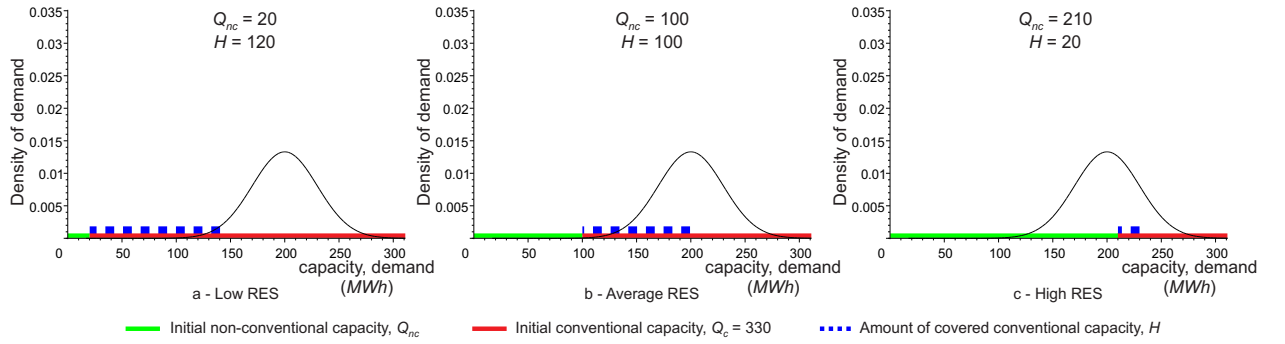


Figure 5: Capacities before installation decisions in the three distinct market settings of the ETS scenario. Capacities are read on the horizontal axis only, whereas the vertical axis shows the density of electricity demand.

4.2 Capacity investment decisions under the BAU and ETS scenarios

In order to assess the environmental outcome corresponding to each market setting, we define the *green ratio*:

$$\text{green ratio} = \frac{Q_{nc} + \Delta Q_{nc}^*}{\mu}.$$

The ratio quantifies the share of the expected value of electricity demand covered by renewable generation. Notice that a green ratio equal to 1 corresponds to just a 50% probability that renewables will cover electricity demand since μ is the 50th percentile of the distribution of D .

Table 4 reports the solutions to Problem (9) and the corresponding green ratios under the BAU and ETS scenarios and for all market settings. Table 5 focuses on the economic variables, reporting the electricity price (Eq. (1)), the price of allowances (Eq. (2)), expected profits (Eq. (8)), and the percentage of expected profits corresponding to the allowance component of solutions. In particular, the latter corresponds to the sum of the allowance component of Eq. (6) multiplied by the probability of event A_2 and the allowance component of Eq. (7) multiplied by the probability of event A_3 . Finally, this sum is divided by the amount of expected profits.

We distinguish between optimal or suboptimal solutions and between normal or degenerate solutions. The first distinction is of mathematical nature: a suboptimal solution is local, whereas an optimal solution is global. In some cases, the problem admits a suboptimal solution that turns out to be of economic interest. The second distinction refers to the outcome of an ETS missing its target, namely emissions below the cap. Unexpected high levels of a normally distributed electricity demand (triggering event A_3) have always a positive probability. However, a solution aiming at exceeding the emissions cap also when electricity demand takes average values will be labeled as degenerate. This is the case where the electricity sector benefits the most from a high allowances price due to de-

liberate non-compliance. Conversely, a normal solution seeks to maximize the probability of event A_2 (where profits result from selling non-conventional generation at the marginal cost of conventional production), resulting in negligible probabilities of event A_3 . Similarly to what happens under the BAU scenario, a normal solution neglects the influence of allowances and turns out to be preferable from an environmental standpoint. It corresponds to the highest green ratio. At the same time, it does not yield high electricity prices.

Table 4: Physical analysis of solutions: expansion of conventional and non-conventional capacities, green ratios, under the BAU and ETS scenarios and for three distinct market settings.

BAU scenario	Market setting			
	Low RES	Average RES	High RES	
Type of solution	Optimal	Optimal	Optimal	
	Normal	Normal	Normal	
ΔQ_c^* (MWh)	-130	-130	-130	
ΔQ_{nc}^* (MWh)	137.5	57.5	-52.5	
Green ratio	0.7875	0.7875	0.7875	
ETS scenario	Low RES	Low RES	Average RES	High RES
Type of solution	Suboptimal	Optimal	Optimal	Optimal
	Normal	Degenerate	Degenerate	Degenerate
ΔQ_c^* (MWh)	-130	-130	-130	-130
ΔQ_{nc}^* (MWh)	133.5	57	-10.5	-63
Green ratio	0.7675	0.3850	0.4475	0.7350

Let us discuss the solutions under the BAU scenario first. Actually, we can talk about a unique solution. A quick inspection of Table 4 reveals that the only apparent difference across the three distinct market settings is about ΔQ_{nc}^* . However, the final installed renewable capacity ($Q_{nc} + \Delta Q_{nc}^* = 157.5$ MWh) is constant in all market settings. As for conventional capacity, we analytically show in the Appendix (under the BAU and ETS scenarios) that it has a negative impact on expected profits. Indeed, the optimal solution in all market settings ($\Delta Q_c^* = -130$ MWh) consists in reducing it up to the security of supply conventional capacity. Consequently, the green ratio remains constant too. The

Table 5: Economic analysis of solutions: electricity prices, allowance prices, expected profits, allowance components of profits, under the BAU and ETS scenarios and for three distinct market settings.

BAU scenario	Market setting			
	Low RES	Average RES	High RES	
Type of solution	Optimal	Optimal	Optimal	
	Normal	Normal	Normal	
p_0 (€/MWh)	55.30	55.30	55.30	
$p_{a,0}$ (€/tonne)	0	0	0	
$\mathbb{E}(G)$ (€)	7217.10	7217.10	7217.10	
Allowance component of $\mathbb{E}(G)$ (%)	0	0	0	
ETS scenario	Low RES	Low RES	Average RES	High RES
Type of solution	Suboptimal	Optimal	Optimal	Optimal
	Normal	Degenerate	Degenerate	Degenerate
p_0 (€/MWh)	57.15	119.38	130.04	152.76
$p_{a,0}$ (€/tonne)	0.71	53.98	63.68	86.43
$\mathbb{E}(G)$ (€)	7316.13	8370.96	10721.88	21057.37
Allowance component of $\mathbb{E}(G)$ (%)	0.02	0.55	0.58	0.67

optimal solution under the BAU scenario is normal since, by construction, there is no ETS. Turning to the economic perspective, the electricity price is equal to 55.30 €/MWh. Absent an allowances market, this corresponds to the lowest price in all market settings. Similarly, expected profits for the electricity sector take the lowest value (7271.10 €); they do not include any allowance component.

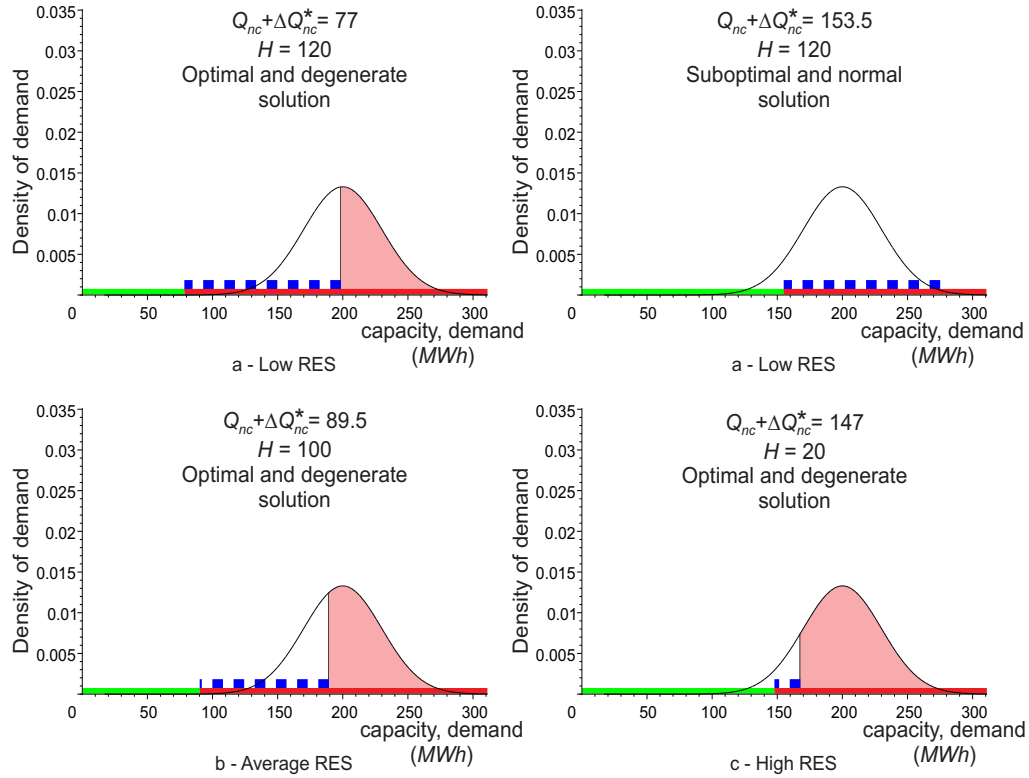
In contrast to the BAU scenario, Table 4 shows that the solutions under the ETS scenario are affected by the different market settings. The table reports the physical features of four solutions, three optimal and one suboptimal. However, a common feature of these solutions is that $\Delta Q_c^* = -130$ MWh, the same value as under the BAU scenario.

The (mathematically) suboptimal solution occurs in the low RES market setting and it is similar to the optimal and normal solution under the BAU scenario. In this market setting, the resulting non-conventional capacity and the green ratio are close to the BAU scenario. This solution is normal since the probability of event A_3 is approximately zero.

Recall from Eq. (2) that allowance prices are linked to the probability of event A_3 by $\mathbb{P}(A_3) = p_{a,0}/f = p_{a,0}/100 = 0.71\%$. Correspondingly, $p_{a,0} = 0.71 \text{ €/tonne}$; $p_0 = 57.15 \text{ €/MWh}$ is also low. Expected profits and the allowance component are slightly higher than under the BAU scenario.

The three optimal solutions under the ETS scenario are all degenerate. The installed renewable capacity, $Q_{nc} + \Delta Q_{nc}^*$, varies in response to the different levels of H in the three distinct market settings. In particular, the smaller H the higher the installed renewable capacity, as one would expect under a progressively more stringent ETS. That said, we notice that the installation of renewables, ΔQ_{nc}^* , is systematically lower than that under the BAU scenario. The difference between green capacities is particularly relevant in the low RES and average RES market settings: 80.5 and 68 *MWh*, respectively. In particular, in the average RES market setting, we observe a negative expansion (disconnection/dismantling) equal to -10.5 MWh under the ETS scenario and a positive expansion of 57.5 *MWh* under the BAU scenario. Similarly, the green ratio under ETS is systematically lower than that under BAU. This is counterintuitive: sustained investments in renewables and higher shares of green generation might be expected outcomes of an ETS. On the contrary, the three optimal solutions are degenerate since emissions exceed the cap with substantial probabilities ($\mathbb{P}(A_3) = 54\%$, 64% , and 86.5% , respectively in the low RES, average RES, and high RES market settings). Such probabilities are represented by the areas of the shaded regions in Figure 6. The economic consequences of such solutions are dramatically clear: allowance prices significantly increase, driving electricity prices to exceptionally high levels; expected profits also increase (e.g. almost 300% with respect to the high RES market setting under the BAU scenario), mainly due to the allowance component.

Figure 7 illustrates $\mathbb{E}(G)$ (under the ETS scenario and for all market settings) as a function of the decision variables ΔQ_{nc} and ΔQ_c , under the constraints $Q_{nc} + \Delta Q_{nc} > 0$



— Installed non-conventional capacity, $Q_{nc} + \Delta Q_{nc}$ — Installed conventional capacity, $Q_c + \Delta Q_c$ ■■■ Amount of covered conventional capacity, H

Figure 6: Installed renewable capacities, $Q_{nc} + \Delta Q_{nc}^*$, of the long-term capacity expansion problem in the three distinct market settings of the ETS scenario. Capacities are read on the horizontal axis only, whereas the vertical axis shows the density of electricity demand. In the low RES market setting, both an optimal and degenerate solution and a suboptimal and normal solution are obtained.

and $Q_c + \Delta Q_c > 0$. The graphical relationship between $\mathbb{E}(G)$ and ΔQ_{nc} is self-evident. Conversely, the dependence of $\mathbb{E}(G)$ and ΔQ_c is not that neat. Yet, as shown in the Appendix, the partial derivative $\partial\mathbb{E}(G)/\partial\Delta Q_c$ is negative over all the domain.

Notice that the conventional capacity investment strategy of the monopolist is simple. It has an incentive to reduce the installed conventional capacity $Q_c + \Delta Q_c$ to $H + \epsilon$, with $\epsilon \rightarrow 0^+$ (i.e. just enough to make event A_3 possible). Yet, the supply constraint prevents the monopolist from adopting such an extreme solution. This is clearly observable in the figure, where the optimum occurs at $\Delta Q_c = S - Q_c$. However, the corresponding expected profits are lower than what would be attainable at $\Delta Q_c = H - Q_c$. Finally, observe that, for $\Delta Q_c < H - Q_c$, expected profits drop because A_3 becomes impossible. The incentive to disconnect/dismantle conventional capacity illustrated here is related to the so-called “missing money problem”. Among others, capacity compensation schemes (e.g. reliability options, capacity markets) and the application of penalties to producers for electricity demand left unsatisfied are alternative ways to address the security of supply.

The mathematical details of $\mathbb{E}(G)$, in particular its partial derivatives with respect to both ΔQ_{nc} and ΔQ_c , are obtained and discussed in the Appendix, both under the constraints of Problem (9) and considering only the constraints $Q_{nc} + \Delta Q_{nc} > 0$ and $Q_c + \Delta Q_c > 0$. In the Appendix, we also discuss the dependence of allowance and electricity prices under the ETS scenario as functions of ΔQ_{nc} .

To summarize, although one would expect that an ETS will sustain investments in renewables in the long-term, our analysis shows that this is not the case when the electricity sector acts cooperatively. Green capacity investments and green ratios are higher under BAU than under ETS, highlighting the distortionary effect of an ETS. A tighter emissions cap does not drive greater green capacity investments since the opportunity of exceeding the cap remains unaffected. The effect of regulatory adjustments is discussed in Section 5.

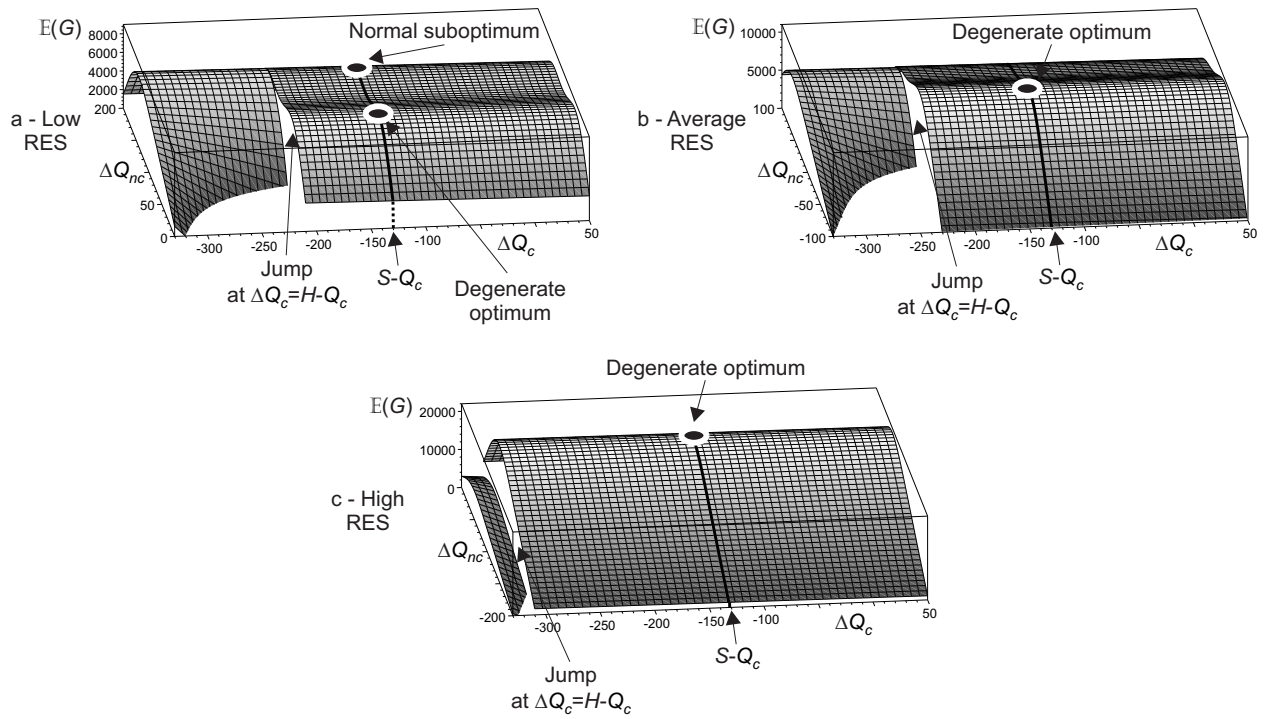


Figure 7: Expected profits, $\mathbb{E}(G)$, as a function of ΔQ_c (installation decision of conventional capacity) and ΔQ_{nc} (installation decision of non-conventional capacity), subject to the constraints $Q_c + \Delta Q_c > 0$ and $Q_{nc} + \Delta Q_{nc} > 0$. The three panels refer to the market settings adopted in the ETS scenario.

5 Sensitivity to key assumptions

Our benchmark set up corresponds to a one-period model, where the long-term capacity expansion decision is taken under uncertainty over the future electricity demand. Immediately after the decision is taken, demand is realized and electricity is dispatched. By focusing the analysis on a single period, the benchmark model abstracts from the possibility of capacity adjustments, banking of allowances, and regulatory adjustments. In this section, we qualitatively discuss the sensitivity of our results to these key modelling choices and to two model assumptions: perfectly inelastic electricity demand and the use of a monopolistic framework.

Two- and multi-period frameworks A proper analysis of a multi-period decision framework requires dynamic programming techniques and it is beyond the scope of this work. Yet, it is possible to explore the likely impact of introducing an intermediate time $\tau \in (0, T)$, where adjustment of capacity can occur by building on the main lessons learned from real options theory. For ease of exposition, let us suppose that the residual period $T - \tau$ is sufficiently long to cover the entire lifetime of new capacity investments. Also, since the derivative of $\mathbb{E}(G)$ with respect to ΔQ_c is negative and independent from D , we concentrate the analysis on ΔQ_{nc} .

As time passes, information accumulates. Thus, at time $t = \tau$, more information about D is available. Under the real options approach, this introduces for the monopolist an opportunity to optimally delay part of (or the entire) capacity expansion.

To see this, let us call $\Delta Q_{nc,0}^*$ the decision at time $t = 0$ and $\Delta Q_{nc,\tau}^*$ the decision at time $t = \tau$ and let us compare the result $\Delta Q_{nc,0}^* + \Delta Q_{nc,\tau}^*$ and the optimal expansion decided in a one-period framework (ΔQ_{nc}^*). A qualitative description of this comparison can be obtained examining panels b of Figures 11 and 12, where the blue curves correspond to the

optimal solutions with a less uncertain D (i.e. smaller value of $\sigma = 10$). According to the real options theory, these solutions can be seen as if they were obtained under a two-period framework. By the same token, the red curves correspond to the optimal solutions in the one-period framework ($\sigma = 30$, i.e. more uncertain D). We can observe that, when, in the one-period framework, the optimal solution seeks event A_3 , then we have $\Delta Q_{nc,0}^* + \Delta Q_{nc,\tau}^* < \Delta Q_{nc}^*$, that is the disconnection/dismantling in the two-period framework will be even more pronounced than that in the one-period framework. Vice versa, when, in the one-period framework, the optimal solution is normal, then the conclusion is reversed: $\Delta Q_{nc,0}^* + \Delta Q_{nc,\tau}^* > \Delta Q_{nc}^*$.

In summary, we can expect that our results could be extended to the two-period framework. Also, this line of reasoning could extend the discussion from a two-period to a multi-period framework.

Banking of allowances Most of existing ETS allow for some form of banking of unused allowances between phases for future compliance. Borrowing future allowances for present compliance is uncommon. To account for banking, we extend our benchmark model introducing the intermediate time $T_1 \in (0, T)$ such that, if $[0, T_1]$ emissions exceed the $[0, T_1]$ cap, the penalty for non-compliance f is paid.

The possibility to bank allowances has no consequences for our results. As shown in Carmona and Hinz (2011) and Grüll and Taschini (2011) with banking, the allowances price at time $t = 0$ can be decomposed into two parts: the expected value of non-compliance in $[0, T_1]$ and the expected value of non-compliance in $(T_1, T]$, namely the banking value. As shown in the previous cited papers, this sum is larger than the allowances price evaluated in a single-phase framework. Therefore, the introduction of an intermediate time does not reduce (possibly increases) the chances for the monopolist to be in non-compliance.

Regulatory adjustments To explore the likely impact of regulatory adjustments, possibly occurring after the capacity investment decision of the monopolist, we comment Figure 8, which shows expected profits, $\mathbb{E}(G)$, as a function of H and f , respectively, for different levels of the pass-through coefficient β . The figure is obtained under the average RES market setting (see Tables 2, 3, and 4). First of all, we can see that the dependence of $\mathbb{E}(G)$ from both f and H depends on the level of β . In particular, when β is sufficiently large, expected profits for the monopolist increase (linearly) with f and decrease (not linearly) with H .

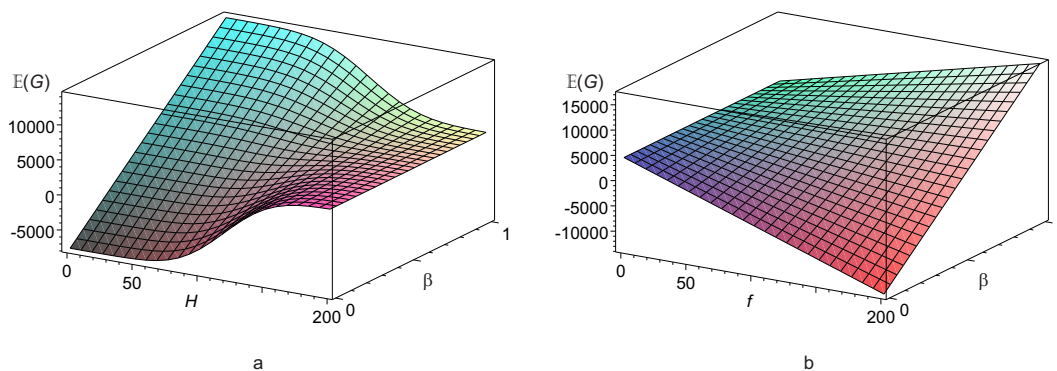


Figure 8: Expected profits, $\mathbb{E}(G)$, as a function of H (panel a) and f (panel b), for different levels of the pass-through coefficient β .

Therefore, we can argue that, in the case the regulatory authority would adjust one or both the parameters to reduce the profit opportunities for the monopolist, it should reduce f and/or increase H . Notice, in particular, that, for low values of f and high values of H , $\mathbb{E}(G)$ flattens out to a level which is independent of β . Such a level corresponds to $\mathbb{E}(G)$ under the BAU scenario (i.e. where the price of allowances falls to zero). Intermediate adjustments do not cancel the incentive to distort prices by the monopolist. Therefore, either the regulatory authority selects f and H corresponding to the BAU scenario, or the monopolist will always seek degenerate solutions. Unfortunately, such an adjustment

corresponds to ruling out the ETS.

Inelastic electricity demand Our benchmark model assumes a perfectly inelastic electricity demand D . In particular, D is normally distributed with constant mean μ and constant standard deviation σ . However, one may contend that consumers will respond to the prospects of high electricity prices and D may not be perfectly elastic. Without imposing any specific relationship between D and electricity prices, we can reasonably assume that higher electricity prices reduce demand or, equivalently, decrease μ . By varying μ , we can explore the effect of an elastic electricity demand and argue that it is inconsequential.

To build intuition, let us consider the case where consumers can react to the increase of electricity prices by investing in (non-conventional) auto-generation. We capture the impact of this reaction by introducing the random variable D_n representing the resulting net electricity demand. This change of variables has no consequences for our analytical results.

Let D_h represent the uncertain self-satisfied electricity demand (self-consumption). We assume that it is normally distributed with expected value μ_h and standard deviation σ_h . We express the resulting net electricity demand as

$$\begin{aligned} D_n &= D - D_h \sim \mathcal{N}(\mu, \sigma^2) - \mathcal{N}(\mu_h, \sigma_h^2) \\ &\sim \mathcal{N}(\mu - \mu_h, \sigma^2 + \sigma_h^2 - 2\rho\sigma\sigma_h), \end{aligned}$$

where D and D_h are jointly normally distributed and ρ is the linear correlation coefficient, which can be assumed positive.

To illustrate the effect of a more elastic D , we let μ_h vary and set $\sigma_h = 10$, $\rho = \frac{1}{6}$, and $D \sim \mathcal{N}(200, 30^2)$. Substituting, we obtain $D_n \sim \mathcal{N}(200 - \mu_h, 30^2)$. The remaining settings of Q_c , Q_{nc} , and H are the same as those in Table 3. Table 6 summarises the

impact of an increasing demand elasticity on ΔQ_{nc}^* in the three distinct market settings of the ETS scenario.

Table 6: Optimal/suboptimal installation of non-conventional capacity for some values of μ_h , the expected value of D_h .

Market setting ^a	Type of solution	ΔQ_{nc}^* (MWh)			
		$\mu_h = 0$	$\mu_h = 10$	$\mu_h = 20$	$\mu_h = 50$
Low RES	Degenerate	57	52	48	-
Low RES	Normal	133.5	125.5	117.5	93
Average RES	Degenerate	-10.5	-17	-23	-33.5
High RES	Degenerate	-63	-71.5	-80	-105

^a The low RES market setting is characterized by two solutions, which are labelled as normal and degenerate (see Section 4.2).

The degenerate solutions of all market settings are optimal, whereas the normal solutions obtained for the low RES market setting are suboptimal, except for the optimal and normal solution corresponding to $\mu_h = 50$.

Therefore, we can infer that an increasing demand elasticity (higher values of μ_h) pushes the monopolist to reduce investments in non-conventional capacity more aggressively. Although unreported, the green ratios remain unaffected.

Fully competitive market Let us hypothesize that the energy-mix decision is adopted competitively and independently of the decisions of the other producers. As it can be easily argued, in a competitive framework, each producer exclusively expands renewables and the resulting energy-mix would include only green technologies; conventional plants would be completely replaced. This outcome is highly implausible (and problematic) for different reasons. First, since electricity demand would be met only by non-conventional plants, allowance prices, electricity prices, and expected profits would drop to zero for all producers. This calls into question the economic sustainability of the electricity sector itself. Second, with an energy-mix dominated by intermittent renewables, the security of supply would be at risk. Third, we have been observing a significant slowdown of investments in non-conventional plants in the recent years, which can be explained (at least partially) as a

non-competitive stance of the electricity sector to prevent the adverse outcomes described above.

6 Conclusions

This paper addresses the tradeoff that defines the long-term capacity expansion decision of a monopolist in energy-only markets. We specifically investigate the factors that determine the optimal/suboptimal energy-mix decision of the monopolist in the context of an Emissions Trading System (ETS). Understanding the expected outcomes and the tradeoff associated with such a decision is critical for ensuring effective environmental legislation and electricity market reforms.

In this paper, we present a model under uncertain electricity demand and derive analytical dependencies between the expansion decision and market prices. We show that increasing the share of renewables (1) provides the highest profitability and (2) reduces the chances that an ETS is compliant, which is the most desired outcome for the monopolist. In particular, we find that, under both a BAU scenario (absence of emission regulations) and an ETS scenario, the monopolist has an incentive to maintain the renewable capacity at the levels that do not fully satisfy electricity demand. However, under the ETS scenario, the monopolist has an opportunity to create larger infra-marginal profits by reducing renewable capacity even more markedly. This opportunity consists in setting up an energy-mix such that the emissions exceed the cap in a systematic fashion, i.e. even under average values of electricity demand.

The distortion described in this paper is twofold: first, emissions exceed the cap with high probability; second, prices of electricity and allowances are inflated. The monopolist leverages on the first seeking for the second. As we have shown, under such market structure, the regulatory authority is completely defenseless. Other policies, for example a

carbon tax, could lessen (or even completely eliminate) this distortion possibly at the cost of lower economic efficiency.

Perhaps surprisingly, an unintentional consequence of an ETS is an alleviation of the “missing money problem”. Even in the absence of a security of supply constraint, the monopolist will not reduce the conventional capacity below the emissions cap since, otherwise, the distortion of allowances and electricity prices would not be possible.

The results of this analysis do not necessarily extend to other sectors included into an ETS. What makes the electricity sector subject to the problem discussed here are two key hypotheses: (1) the cooperative oligopoly feature of the electricity sector (which we, equivalently, model as a monopoly) and (2) the uniform auction system adopted in energy-only markets. Related to (1), under perfect competition, renewables will likely reach 100% of the energy-mix. In this case, a virtually zero electricity price will prevail in energy-only markets making electricity generation unprofitable. Therefore, if some degree of concentration is desirable in electricity markets, then the concerns raised in this paper about the energy-mix distortion via an ETS should be an important issue in the energy and environmental policy debate.

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