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We analyze incentives for investing in renewable electricity generating capacity by modeling the trade-off between renewable (e.g. wind) and nonrenewable (e.g. natural gas) technology. Renewable technology has higher investment cost and yields only an intermittent supply of electricity; nonrenewable technology is reliable and has lower investment cost but entails both fuel expenditures and carbon emission costs. With reference to existing electricity markets, we model several interrelated contexts—the vertically integrated electricity supplier, market competition, and partial market competition with long-term fixed-price contracts for renewable electricity—and examine the effect of carbon taxes on the cost and share of wind capacity in an energy portfolio. We find that the intermittency of renewable technologies drives the effectiveness of carbon pricing mechanisms, which suggests that increasing emissions prices could unexpectedly discourage investment in renewables. We also show that market liberalization may have a negative effect on investment in renewable capacity while increasing the overall system's cost and emissions. Fixed-price contracts with renewable generators can mitigate these detrimental effects, but not without possibly creating other problems. Actions to reduce the intermittency of renewable sources may be more effective than carbon taxes alone at promoting investment in renewable generation capacity.

Key words: Electricity Generation, Renewables, Intermittency, Capacity Planning and Investment, Incentives and Contracting

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1. Introduction

Renewable (or "green") sources of energy, such as wind and solar power, will play a key role in the future energy landscape. By providing emission-free and sustainable energy, these sources are important alternatives to fossil fuels. The worldwide increase in capacity installations for renewables has been accelerating; in the last decade, wind capacity installations have increased tenfold. The United States has the highest level of installations with 25 gigawatts (GW), followed by Germany (24 GW), Spain (17 GW), China (12 GW), and India (9 GW). A critical aspect of renewable technologies is their *intermittency*–that is, the supply of electricity from these sources is uncertain. For instance, wind blows neither continuously nor in concert with demand, and electricity generation from solar panels is volatile because of their sensitivity to weather conditions, air pollution, and other determinants of solar radiation intensity. Although some of this variability in supply is natural and can be planned for (e.g., the lack of generation from solar panels at night), there is still significant uncertainty associated with the outputs of renewable technologies. A main goal of this paper is to investigate the effect of generation intermittency on investment in renewable capacity.

Investment in renewable energy capacity is hampered not only by intermittency but also by the high costs involved. A variety of strategies have been adopted to incentivize investment in renewables. These include renewable portfolio standards, minimum prices for energy from renewable energy injected into the grid (a.k.a. renewable feed-in tariffs), and multiyear subsidies and investment credits in some jurisdictions as direct incentives for new renewable capacity.[1] In addition to these direct incentives for renewable investment are indirect incentives based on increasing the price of fossil-fuel electricity generation (gas-fired, coal, etc.) by penalizing firms for the environmental damage these technologies cause. The most significant of these penalties is referred to generically as *carbon pricing*.[2] This paper aims to understand the relationship between supply intermittency and the effectiveness of carbon pricing strategies.

Besides the introduction of renewables, electricity markets have undergone another important change in the last two decades: market liberalization. In the past, electric utilities were vertically integrated; this means that the functions of generating, transmitting, retailing, and distributing electricity were all performed by a single utility company. The logic of this approach was based on operational constraints associated with balancing the generation, transmission, and distribution of electricity. That balancing also contributed to the economics of electricity generation because it reduced retailing costs (Michaels 2007). The first step toward the liberalization of electricity markets was "vertical unbundling" of the industry's generators and retailers. Such restructuring was motivated by the desire to create competition among generators, thereby reducing retail prices, and to prevent incumbent utilities from exercising the market power deriving from their historically dominant position. Market liberalization has rendered electricity a commodity that can be traded in wholesale electricity markets. These markets are typically organized through a national or regional pool, with an independent system operator (ISO) responsible for assuring stability and control of the interconnecting transmission network. The pool (or spot) prices in these markets are determined by a complex set of bidding and dispatching rules that vary widely across countries and regions. Yet all these markets share a common characteristic: significant volatility of spot prices. The reason is that, with some minor exceptions, electricity cannot be economically *stored* and so supply and

[1] See Bushnell (2010) for a critical review of various incentives for renewable energy investments.

[2] Proposals for pricing the carbon emissions from fossil-fuel electricity plants include a carbon tax or a "cap and trade" system of credits. For a discussion of various forms of carbon pricing in the context of technology planning, see Drake et al. (2010).

demand must be continually balanced. The need to achieve this balance in a decentralized fashion through competitive electrical power markets implies that a pool price reflecting the marginal cost of the last unit dispatched will vary considerably over time, driven as it is by economic and technical uncertainties in supply and demand as well as by uncertain exogenous variables such as weather conditions.

Motivated by the two developments just described, in this paper we study the effect of market liberalization on investment in renewable electricity generation capacity. In particular, we highlight the role that supply intermittency plays in determining the competitiveness of renewables in a liberalized market. We propose a stylized economic model based on the key features of electricity markets. This model features two electricity generators (e.g., wind and gas) that make capacity investment decisions given the pricing mechanism established by the electricity retailer. Shortfalls in supply are procured from backup generators. The model captures uncertainty in both the supply of and the demand for electricity, and we use it to answer several broad questions. How does intermittency affect capacity investment in renewables? Is the intermittency-driven comparative disadvantage of renewables simply a cost issue? How will taxing emissions from fossil-fuel generation change the share of green technologies in energy portfolios and in total emissions?

Within this framework, we study how carbon taxing would affect investment in renewable and nonrenewable electricity generation capacities. We find that increasing the carbon price has two counteracting effects on investments in renewables. On the one hand, it improves the cost competitiveness of renewables relative to non-renewable technologies—a result of the former's lower greenhouse gas (GHG) emissions. On the other hand, renewables require backup generation, which typically comes from generators using fossil fuels; thus an increase in the carbon price leads to an increase in the cost of reserves to cover intermittency. How these counterforces affect the technology share of renewables in the overall generation portfolio depends on the carbon price and also on the emission intensity of backup generation technologies. Often it is the older, more emission-intensive technologies that are used as backup. So in stark contrast to intuition, increasing the carbon price may actually reduce the overall proportion of renewable generation. This effect is present in the vertically integrated setting and also in the liberalized setting. However, in the liberalized market the negative effect of intermittency is amplified by the marginal cost pricing typical of such markets (i.e., the price of electricity is equal to the marginal cost of the unit last dispatched). This finding offers additional and novel support for the hypothesis that market liberalization leads to underinvestment in renewable electric generation capacity (Joskow 2006).

In order to counter these disincentives to invest in renewables in the liberalized market, public policy experts suggest long-term fixed-price contracts with generators so that investment in new generating capacity will be protected from the risk of volatile spot prices (Borenstein 2002). For instance, long-term contracts involving wind developers, electricity suppliers, and large customers are used in the United States and Europe to promote investment in renewable capacity. Such fixed-price contracts with renewable generators are typically benchmarked on feed-in tariffs, often with regulatory guarantees, that specify long-term prices based on generation costs rather than spot prices. We therefore consider an extension of our basic model in which the price of nongreen electricity is determined in the spot market but the retailer sets a fixed price for green electricity ex ante. Using numerical experiments with real-world data, we find that fixed-price contracts are effective at stimulating investment in renewables in a liberalized market. However, overreliance on carbon-intensive backup generation may significantly lessen the environmental benefits of using renewables relative to the vertically integrated case.

This paper makes three principal contributions. First, we study the effect of supply intermittency of renewables on the capacity investment decision, proposing a way (other than average cost) to capture this intermittency cost. Second, we demonstrate how incentives arising from vertical unbundling of the electricity supply's organizational structure affect capacity investments, total cost and emissions, and the share of renewables in the energy capacity portfolio. Third, we obtain the surprising result that increasing the price of carbon can adversely affect investments in renewables owing to the interdependence of renewable and backup capacity, since the latter is almost always a carbon-intensive form. Our analysis leads to new insights about the relative merits of different structures for the electricity market and about the impact of carbon pricing on the promotion of renewable energy sources. Throughout, we use numerical analysis based on real-world data to support our analytical results.

The rest of the paper is structured as follows. In Section 2 we review the related literature and position our paper. Section 3 lays out the foundations of our model. In Section 4 we study a vertically integrated electricity supplier and examine the effect of intermittency on decisions about capacity decisions. In Section 5 we analyze market competition, and Section 6 considers fixed-price contracts for green electricity. Section 7 concludes.

2. Literature Review

Our paper belongs to the growing literature on sustainable operations (Kleindorfer et al. 2005), a field of considerable interest to operations researchers who tackle the sustainability challenges that various organizations face in their daily decisions. Given the ever-increasing relevance of sustainability issues to businesses, this literature spans a wide variety of operational issues; these include green process design (Sosa 2011), closed-loop supply chains (Savaskan et al. 2004), and optimal incentive strategies for adoption of green products (Avci et al. 2012; Lobel and Perakis 2011). Our paper considers another general operational problem—namely, adoption of green technology while accommodating the new necessities induced by the "carbon economy". Along these lines, Islegen and Reichelstein (2011) characterize the break-even carbon emission price that induces adoption of technology to capture and store carbon, an undertaking that is costly but does significantly reduce the firm's emission intensity. Closer to our model is Drake et al. (2010). Though in a context other than electricity generation, their decision maker also faces a trade-off between investing in a "clean" versus a "dirty" technology when emission costs are a possibility. These authors suggest, as we do, that increasing carbon prices might have an adverse effect on investment in the clean technology. Yet unlike our model, theirs does not consider supply intermittency; also, the adverse effect they identify is "carbon leakage" (i.e., increasing dirty production in unregulated regions).

Within the sustainable operations literature, most of the papers that consider the intermittency of renewable energy sources do so from the standpoint of *short-term* decisions made after the renewable capacity is already in place (see e.g. Zhou et al. 2011). Kim and Powell (2011) characterize the economic value of storage when the renewable owner commits output capacity in the advance electricity market. Wu and Kapuscinski (2012) suggest curtailing the intermittent generation—that is, reducing renewables output through technical methods—in order to balance the system. The effect of intermittency on *long-term* capacity decisions has been explored in various different contexts. For example, Tomlin and Wang (2005) consider a dual-sourcing problem in which the retailer can meet demand by ordering either from a cheap but unreliable supplier or from a more expensive but reliable supplier. At least two important features distinguish our paper from these. First, only we consider incentive issues arising from emission regulation. Second, although these papers focus (as we do) on unreliability and capacity investment, they typically consider only the vertically integrated (monopolistic) setting. Conversely, several other papers study incentives for capacity investment in a vertically unbundled setting but do not consider supply intermittency.[3] Similarly to these papers (e.g., Taylor and Plambeck 2007), this paper considers fixed-price contracts under which a retailer[4] announces a fixed price for (renewable) electricity and the generator/supplier chooses capacity based on the announced price. Our paper emerges from the interfaces of the aforementioned literatures by addressing both supply intermittency and the incentive issues associated with vertical unbundling in the context of integrating renewable energy sources into electricity markets.

Capacity choice and peak-load pricing in electricity markets received significant attention from economists in 1970s and 1980s (for a review, see Crew et al. 1995). Given the characteristics of the

[3] Perhaps an exception is Deo and Corbett (2009), who study yield uncertainty in the vaccine market.

[4] We use the term "retailer" to denote the economic entity with the ultimate responsibility for interacting with the end buyer or customer in the electricity supply chain. Depending on the context, this retailer could be a "supplier", an independent broker or wholesale power intermediary, a distribution company, or (in the case of vertical integration) the division of an industrial company that is responsible for installing its own self-generation.

electricity markets at that time, these studies focused on monopolistic settings. For instance, Crew and Kleindorfer (1976) model joint determination of capacity and prices when demand is uncertain and there are several technologies (with different cost structures) available. Chao (1983) extends this analysis by considering uncertain supply in a monopolistic setting. Vertical unbundling of the electricity supply chain and introducing competition to the market for generation have drawn fresh attention to this field. Liberalized electricity markets have been the subject of a fast-growing stream of research (for a detailed review, see Ventosa et al. 2005). Models of liberalized markets can be separated into short-term pricing/dispatching models and longer-term investment models. Elmaghraby (1997) studies optimal auction mechanisms for achieving efficiency in electricity markets when firms have already made their investment decisions (other examples include Borenstein et al. 2000; Green and Newbery 1992). Longer-term investment incentives are examined in papers, such as Von der Fehr and Harbord (1997) and Castro-Rodriguez et al. (2009), that consider capacity investment decisions—often in the context of Cournot competition. The main finding reported by these papers is that, consistently with the broader Cournot literature, decentralization (vertical unbundling) leads to underinvestment in capacity, which in turn leads to higher electricity prices.

Economic research on renewable energy sources has examined the theory of efficient integration of renewables into grid operations as well as the empirical evidence regarding cost competitiveness. A key finding of this literature (e.g., Owen 2004) is that renewables are competitive and efficient when the pricing of traditional sources of energy, such as fossil fuels, accurately reflects environmental externalities. The issue of intermittency—along with its cost and reliability implications for electricity generation—has been addressed primarily in empirical studies that are region specific (e.g., Butler and Neuhoff 2008; Kennedy 2005; Neuhoff et al. 2007). A few of the papers in this field (e.g., Ambec and Crampes 2010; Garcia and Alzate 2010) address the issue of intermittency. Much as in our model, both of these papers consider the optimal investment in two types of technologies with different cost structures: an intermittent renewable technology and a reliable fossil-fuel technology. They, too, characterize and compare the optimal capacity investments under vertical integration and competition. Unlike our paper, however, these two consider neither demand uncertainty nor the incentive issues that arise from fixed-price contracting between the generator and retailer of electricity.

3. Model Setup

This section introduces our basic model and assumptions. We consider an electricity retailer, indexed by R, that is responsible for meeting the random market demand. Demand is represented by a random variable $\tilde{D}$ with positive support, distribution function $F(\cdot)$, and density $f(\cdot)$. Two types of electricity generation technologies are available. For expositional purposes we refer to these technology types as wind (W) and gas (G), although these should be viewed as also representing other technology types—for example, photovoltaic and coal—that are, respectively, of renewable (green) and nonrenewable type.

Decision and Generation Parameters. The firm must decide, for each technology, how much to invest in the development of energy capacity. This decision determines not only the long-term limits on electricity production but also the carbon intensity of that production from the resulting electricity generation portfolio. We denote by k_i the decision with respect to capacity investment for each technology type $i \in \{W, G\}$. We denote by $\alpha_i > 0$ the fixed investment and maintenance costs of each unit of capacity, and we represent the unit variable cost (including fuel cost but excluding emission cost) by u_i. We assume that each unit of electricity generation that uses gas capacity results in one unit of GHG emissions, and a will denote the associated "unit emission allowance price". Hence, the total unit variable cost for gas technology is $U_G = u_G + a$. We assume that $u_W = 0$; that is, the fuel and operational costs of the wind generator are negligible. We also assume that wind technology is emission free, so that its total unit cost is $U_W = u_W = 0$. This cost structure is consistent with existing technologies: investment costs for green technologies are significantly higher than for efficient fossil-fuel technologies (e.g., combined heat and power gas turbines), and the latter's variable generation costs—especially when emission costs are included—are significantly higher (Tarjanne and Kivistö 2008). The data that we use for numerical experiments confirms this relationship.

We further assume that the wind technology is intermittent. That is, the production from the available capacity is uncertain and so, from capacity k_W, an actual production amount of only $\tilde{v}_W k_W < k_W$ is obtainable. The random variable $\tilde{v}_W \in [0, 1]$ represents the uncertainty factor in the availability of wind capacity, which we assume (for tractability reasons) to have a two-point distribution: $\tilde{v} = [1, q; 0, 1-q]$. In other words, the capacity is available with probability q and is unavailable with probability $1-q$. This assumption captures the presence/absence of wind (for wind capacity) or sun (for solar panels) but is only a rough approximation of reality in that both wind and sun have continuously varying strengths. Nonetheless, this assumption serves the purposes of capturing intermittency (in its simplest form) while allowing for tractable solutions. We remark that a similar assumption is made by Tomlin and Wang (2005) and Ambec and Crampes (2010) and that our conclusions are not altered if instead we assume a continuous distribution for supply. To unify presentation of the problem, we abuse notation slightly and set $\tilde{v}_G = 1$ as the gas capacity's availability factor.

	Model Factor	Onshore Wind	CCGT
Availability factor	$\mathbb{E}\{\tilde{v}_i\}$	0.25–0.4	0.87–0.97
Capital and fixed O&M cost[a]	α_i	28–40	14–28
Variable cost	u_i	0	40–50
Direct unit emission cost[b]	a	0	10
Total cost	$\alpha_i/\mathbb{E}\{\tilde{v}_i\}+u_i+a$	80–114	70–84

[a] Per installed unit. [b] Assuming an average carbon price of \$20/tonne.

Table 1 Real data for electricity generating costs (\$/MWh) for wind versus conventional combined cycle gas turbine (CCGT) generation. Source: US Department of Energy (EIA 2010).

Data. Table 1 presents the US Department of Energy's 2011 estimates of unit costs for new generation capacity using onshore wind and "combined cycle" gas turbines. Note that these fixed costs are adjusted to account for the availability factors. Each megawatt-hour (MWh) of electricity generated by a combined cycle gas unit has a (CO_2-equivalent) emission footprint of about 0.5 (metric) tonnes. Emission prices in the European spot market have historically been volatile, and the current spot price is about \$20. Within our model framework, then, $a = 10$.[5] These data are fully consistent with our assumptions about generation costs and availability factors of the two technologies under consideration, and we shall use them in all of our numerical experiments.

Supply Function. Because the variable cost of wind is negligible (zero, in our model), it is always dispatched to the grid first. When the total demand exceeds the amount of production by wind technology ($\tilde{D} > \tilde{v}K_W$), the firm uses gas capacity to generate the additional amount required—up to the available capacity. But when demand exceeds the production capacity of both technologies combined ($\tilde{D} > \tilde{v}_W k_W + k_G$), the firm must accommodate the extra demand by drawing on an external *backup* source; this source has infinite capacity, but using it entails a per-unit fuel and operational cost of c. We assume that this backup technology also entails GHG emissions with per-unit intensity e, so the total unit generation cost from the backup technology is $C = c + ae$. We also assume that backup generation is at the upper end of the dispatch merit order in operating cost; that is, $C > \max\{U_G + \alpha_G, \alpha_W/q\}$.[6] Backup capacity should be a fast-reacting generation unit. Typically the less efficient but more flexible technologies (e.g., open-cycle gas turbine) are used for backup generation. These units have higher operating cost and emission intensity, since efficiency losses are incurred when using older generation units, as well as lower load factors resulting from less-frequent usage (Kaffine et al. 2011).[7] Inhaber (2011) provides a comprehensive overview of the

[5] Throughout the paper, we will refer to a, the "emission cost per unit of electricity generation", simply as the "emission price"; it is approximately equal to half the carbon spot price.

[6] We assume that the price of backup generation is fixed. In reality, the amount of installed backup capacity (and hence backup prices) could well be variable in the long run. Although it would be interesting to consider such dynamics in the problem, doing so is beyond the scope of this paper.

[7] An exception is hydro power, which is both fast-reacting and emission free. However the supply of this energy source is limited in many countries.

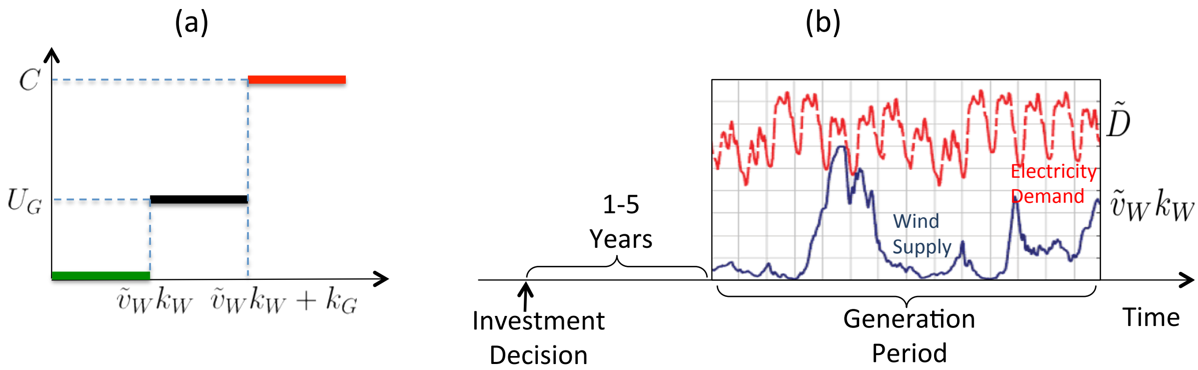

Figure 1 **(a) The supply function. (b) The decision timeline.**

efficiency loss associated with wind intermittency in various countries; the results of that research justify our assumption and, moreover, imply that $e > 1$.[8] Although this inequality is not required for our theoretical results, we will use it in our numerical experiments.

Figure 1(a) plots the short-run supply function for our model world with two technologies and backup. This graph is the standard merit-order dispatch function, which is the basis for ISO pool dispatch operations and for efficiency analysis in the economics literature on electricity generation (see e.g. Hogan 1995).

Timeline. We present the timeline of events in Figure 1(b). The decision about capacities is made *before* realization of demand and of the wind capacity availability factor $\tilde{v}_W \in [0,1]$. There is usually a gap of 1–5 years between an investment decision and actual operation in the market. Once a energy project is on line, demand and supply are realized in real time over a longer operational period. Our model captures these temporal variations by considering one-shot random variables in supply and demand. Hence the expectation operator ($\mathbb{E}$) over the random variables captures expectations over a representative period (e.g., a typical month) during the operational time period, with units of demand and cost all normalized so that they correspond to the length of the chosen representative period.[9]

4. The Vertically Integrated Retailer

For almost a century, the electricity sector resembled a natural monopoly. All four primary elements of electricity supply—generation, transmission, distribution, and retailing—were organized as a vertically integrated firm that was owned either privately or by the state and with price and entry

[8] This by no means implies that using intermittent wind energy leads to higher emissions. Yet it does mean that, because of intermittency, introducing 1 MWh of emission-free wind energy need not lead to eliminating the emissions associated with 1 MWh generated by fossil fuels.

[9] This "representative period" model is standard in both the operations and economics literature. Of course, the definitions of demand, capacity, and variable costs must be consistent with the length of the representative period chosen; (for a review, see Crew et al. 1995).

regulations identical to natural monopolies. In this section we consider a firm that is vertically integrated and thus not only owns the generation capacity but is also responsible for meeting demand. Within this framework, we first consider the case where only one of the technologies is available for generating electricity. In addition to its theoretical importance for comparing the advantages of two different technology types, this section explains the factors underlying capacity choice for each technology. That understanding will be needed when we analyze the case where both types of technology are available.

4.1. Single Technology

When only one technology $i \in \{W, G\}$ is available, the optimization problem of the vertically integrated firm can be formulated as

$$\min_{k_i} \quad \bar{\Pi}_i(k_i) = \mathbb{E}_{\tilde{D}}\{U_i \min(\tilde{D}, \tilde{v}_i k_i) + C(\tilde{D} - k_i)^+\} + \alpha_i k_i. \tag{1}$$

Thus, the firm chooses capacity k_i to minimize expected operating costs (the first term in (1)) plus expected backup generation costs (the second term) plus total investment cost (the third term). Observe that the emission cost is included in the operating and backup costs.

We define the critical ratio $A_i = \frac{\alpha_i}{\mathbb{E}\{v_i\}(C-U_i)}$ so that $A_W = \frac{\alpha_W}{qC}$ and $A_G = \frac{\alpha_G}{C-U_G}$. Intuitively, this is the ratio of the "overage cost": the unit cost of overinvesting in capacity *divided by* the sum of overage cost and underage cost (i.e., the cost of underinvesting in a unit of capacity). In other words, one extra unit of capacity bears one unit of investment cost α_i, but if capacity is not developed and demand exceeds capacity then the expected unit cost for such underinvestment is $\mathbb{E}\{v_i\}(C - U_i)$. Note that our assumption $C > \max\left\{U_G + \alpha_G, \frac{\alpha_W}{q}\right\}$ implies that $A_i < 1$. Let $\bar{F}(\cdot) = 1 - F(\cdot)$ represent the survival function for the random variable $\tilde{D}$. Recall that the distribution function F has increasing failure rate (IFR) if the fraction $\phi(x) = f(x)/\bar{F}(x)$ is increasing;[10] decreasing failure rate (DFR) is defined analogously. Most distributions that are used for practical purposes have IFR; these include the uniform, exponential, normal, truncated normal, and lognormal distributions. There are fewer well-known distributions, such as the Pareto distribution, that have DFR (see Barlow et al. 1996). We next state the solution of the vertically integrated problem with one technology type, where the superscript VI denotes vertically integrated.

Proposition 1. *Suppose that demand distribution has IFR. Then the following statements hold. (a) The unique optimal vertically integrated capacity in the single-technology setting k_i^{VI} for technology $i \in \{W, G\}$ solves $\bar{F}(k_i) = A_i$. (b) $k_G^{VI} \geq k_W^{VI}$ if and only if $A_G \leq A_W$. (c) k_W^{VI} is increasing in a, and k_G^{VI} is increasing in a if and only if $e > 1$.*

[10] We use the terms "increasing" and "decreasing" in their weak sense.

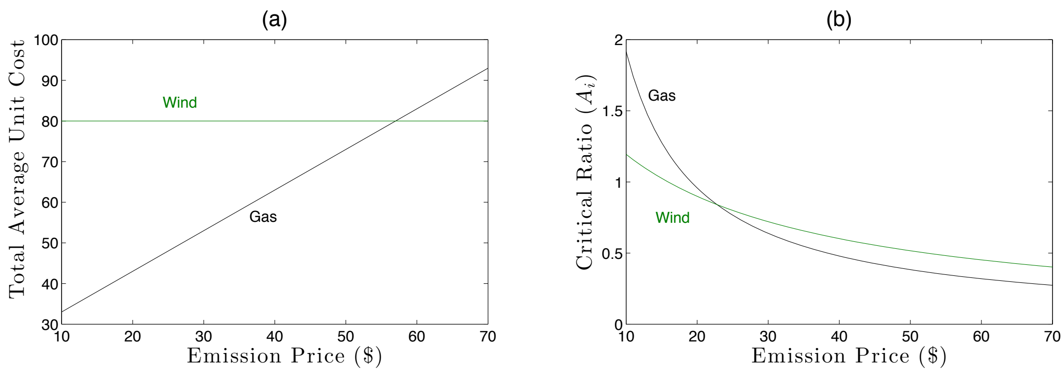

Figure 2 **(a) Total generating cost and (b) critical ratio of the two technologies as a function of the emission price a; here $\alpha_W = 12$, $q = 0.25$, $\alpha_G = 13$, $u_G = 40$, and $e = 2.2$.**

The solution is essentially equivalent to the well-known newsvendor solution in the operations literature (Cachon and Terwiesch 2006): the probability of meeting the demand via the backup capacity ("rationing demand" in the newsvendor context) is the ratio of overage costs to overage plus underage costs. It follows that, as A_i increases, the optimal capacity for technology i decreases. Hence we can view A_i as a cost: the higher is A_i, the less attractive is the focal technology. As a consequence, part (b) of the proposition states that the technology with the lower critical ratio will have the higher capacity.

We remark that this critical ratio approach to technology investment decisions is different from simply using total average cost. The total average unit generating cost is α_W/q for the wind technology and $\alpha_G + U_G$ for the gas technology. Yet comparing these two total average unit costs is not equivalent to comparing the respective values of A_i. As is evident from Figure 2 (which is based on the real data in Table 1), the total average generating cost of the gas technology is higher than that of wind technology when the emission price is high ($a > 57$, which is equivalent to a carbon spot price of about \$30). At about $a = 25$, however, the gas technology's critical ratio falls below that of wind technology—implying that, for emission prices near this value, the gas capacity exceeds the wind capacity even though the former technology has higher generating cost. Looking at the critical ratio rather than the total average cost has the advantage of taking into account the effect of intermittency. The total average cost of the wind technology is independent of the price a of carbon emissions and of how emission intensive the backup technology is (as reflected in the parameter e); in contrast, the wind technology's critical ratio depends on these factors. Finally, the magnitude of backup cost c affects the total average costs of neither technology, whereas the same cannot be said for their respective critical ratios.

According to part (c) of Proposition 1, the amount of wind capacity is always increasing in the price of carbon allowance a. This relation does not always hold for natural gas technology.

Indeed, we should expect gas-based capacity to be *decreasing* in the carbon price when the backup technology is less emission intensive or when its price is independent of the carbon price. If $e > 1$—that is, if the backup technology is more emission intensive than the gas technology (as is usually the case in practice)—then gas capacity is also increasing in the carbon price.

4.2. Two Technologies

When both technologies are available, the firm's objective is to minimize the expected production and capacity costs subject to meeting all the demand and while dispatching the wind technology first:

$$\min_{k_W,k_G} \bar{\Pi}(k_W,k_G) = \mathbb{E}_{\tilde{D}}\mathbb{E}_{\tilde{v}_W}\left\{U_W \min(k_W,\tilde{D}) + U_G \min(k_G,\tilde{D}-\tilde{v}k_W)^+ + C(\tilde{D}-\tilde{v}k_W-k_G)^+\right\} - \alpha_W k_W - \alpha_G k_G. \tag{2}$$

Proposition 2 characterizes the solution to the vertically integrated problem formulated in (2). The index VI denotes vertically integrated.

Proposition 2. *(a) The optimal capacities for each technology, k_W^{VI} and k_G^{VI}, are unique and jointly solve the following first-order conditions:*

$$\begin{aligned} q\bar{F}(k_W+k_G) + (1-q)\bar{F}(k_G) &= A_G \\ \left(1-\frac{U_G}{C}\right)\bar{F}(k_W+k_G) + \frac{U_G}{C}\bar{F}(k_W) &= A_W; \end{aligned} \tag{3}$$

furthermore, the two types of technologies are strategic substitutes. (b) If $A_W \lesseqgtr A_G$ and $q \gtreqless 1 - U_G/C$, then $k_W^{VI} \gtreqless k_G^{VI}$. (c) The optimal capacity k_W^{VI} (resp., k_G^{VI}) is increasing (resp., decreasing) in q and u_G. (d) The optimal capacity for each technology k_i^{VI}, $i \in \{W,G\}$, is decreasing in its own unit investment cost α_i and increasing in the other technology's unit investment cost α_{-i}.

The first observation we make is that the set of equations (3) that characterizes the optimal solution with two technologies resembles the solution to the single-technology case. Essentially, the left-hand side of each equation is a convex combination of the probability of rationing demand when both capacities are available and when only one of the capacities is available. In particular: when $A_W \to 1$ it is straightforward to verify that $k_W^{\mathrm{VI}} = 0$; when $A_G \to 1$ we have $k_G^{\mathrm{VI}} = 0$, which reduces (3) to the solution in the single-technology case $\bar{F}(k_i) = A_i$.

In part (b) of the proposition we can see that, similarly to the single-technology case, the critical ratio A_i plays a role in determining the economic attractiveness of the technology. When $A_W < A_G$ and q is high ($q \geq 1 - U_G/C$), the optimal wind capacity is higher than the optimal gas capacity. Parts (c) and (d) state intuitive comparative statics results. Keeping all else constant, as wind technology becomes more reliable (i.e., as q increases) the firm invests more in this technology. Also, when the variable cost of gas generation increases, the firm has more incentive to invest in wind generation. An increase in the unit investment cost of each technology i leads to a decrease in its capacity at the optimum, and—because the two capacity types are substitutes—the result is an increase in the other capacity type. The following proposition provides (somewhat less intuitive) comparative statics results regarding the cost of backup generation and the carbon price.

PROPOSITION 3. *(a) The optimal capacity for gas-based generation k_G^{VI} is increasing in the unit backup price c. If the distribution function of the electricity demand has IFR, then the optimal capacity for wind is decreasing in c; otherwise, it is increasing in c. The total optimal capacity $k_W^{VI} + k_G^{VI}$ is increasing in c. (b) If $e \leq 1$ (i.e., if backup emission intensity is lower than gas), then k_W^{VI}/k_G^{VI} is strictly increasing in the unit price of the carbon allowance a. This relation does not necessarily hold when $e > 1$.*

It is interesting that monotonicity of the optimal capacities in the cost of backup generation does not depend on the marginal production and capacity costs of wind and gas. Rather, it depends on the structure of the demand distribution and, in particular, on its failure rate. Proposition 3 states that—regardless of the relative magnitude of production costs for wind and gas—increased backup cost always leads to higher gas capacity and, if we assume an increasing failure rate, to a decrease in wind capacity. This is a direct consequence of wind's intermittency and its primacy in the dispatch order. In fact, if the wind technology is *not* intermittent ($q = 1$), then the amount of wind capacity does not change as c increases whereas gas capacity is increasing in c (see the proof of Proposition 3 in the Appendix). An increase in c leads to higher cost of underage for wind. There is, however, a second effect: since an increase in c leads to more gas capacity, the probability of having "low" underage (when demand does not exceed the capacity of wind plus gas) increases. Which effect dominates depends on the failure rate of demand distribution: when the failure rate is increasing there is more likely to be demand in the region between wind and wind + gas; hence the probability of "low" underage increases rapidly while the probability of "high" underage decreases. As a result, the optimal wind capacity decreases.

Another counterintuitive result is related to part (b). We fully expect that, when the emission price increases, the share of wind technology also increases. However, it turns out that this is true only when $e < 1$. It would be reasonable to suppose that, when the carbon price a increases, it leads to a similar comparative statics effect as in the single-technology case when $e > 1$: if the backup technology is more carbon intensive than the gas technology, then an increase in the carbon price a leads to higher capacity investment in both technologies—although wind capacity might grow more rapidly because of the lower emissions involved. Moreover, if there are two technologies then

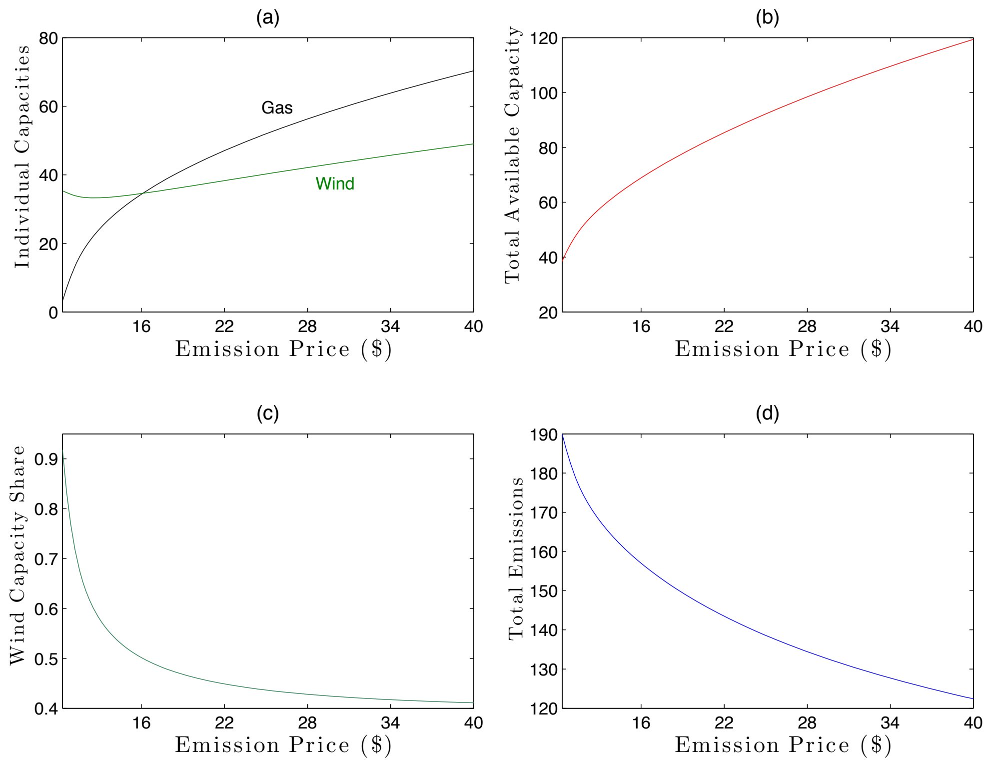

Figure 3 **(a) Individual capacities, (b) total available capacity $qk_W^{\mathsf{VI}} + k_G^{\mathsf{VI}}$, (c) share of wind capacity $k_W^{\mathsf{VI}}/(k_G^{\mathsf{VI}} + k_W^{\mathsf{VI}})$, and (d) total emissions as functions of the price of emission allowance in the vertically integrated case; here $\tilde{D} \sim \log N(100, 50)$, $\alpha_W = 28$, $q = 0.35$, $\alpha_G = 23$, $u_G = 45$, $c = 45$, and $e = 2.2$.**

the substitution effect also comes into play; that is, as gas technology becomes more expensive, one would expect that the investment in wind would further increase (because it substitutes for gas). Yet as illustrated in Figure 3, this is not what happens. The numbers that underly this figure (and all the other figures) are consistent with the real-world data provided in Section 3. We observe that, as the carbon price increases, investment in gas capacity increases significantly while the wind capacity barely changes and even decreases for a certain range of carbon prices. The reason is that, when $e > 1$, the cost of intermittency for wind increases as a increases because the backup technology becomes more expensive. Hence wind technology becomes *less* attractive relative to gas. Moreover, when $e > 1$, an increase in the price of carbon allowance a also leads to an increase in the optimal gas capacity. Because the two capacities are substitutes, this has an adverse effect on optimal wind capacity and explains the corresponding decrease in its share of electricity production. A higher carbon price naturally leads to less total emissions, as shown in Figure 3(d), but this reduction reflects a substitution of emission-intensive backup for gas and not, as one might expect, an increase in wind capacity. This dynamic may also explain the decreasing marginal benefit from increasing carbon price. Thus, even in the vertically integrated scenario, higher carbon prices may be ineffective at stimulating investment in renewable energy sources.

5. Market Competition

In this section we consider a liberalized market in which two firms are competing through their capacity decisions. We model this situation as a noncooperative game, with each firm's capacity decision affecting the other firm's profit via the market price. We shall first elaborate on the market pricing mechanism and then present our capacity game. We also explore how moving from a vertically integrated setting to a game setting changes the decisions for each capacity type.

5.1. Marginal Cost Pricing

In a competitive electricity market, power generators typically submit their supply offers to the market (grid or pool) administrator and retailers (representing their end-use electricity customers) submit their demand bids. The independent system operator then sorts the supply offers from the lowest to the highest before scheduling dispatch based on the merit order—subject to transmission (and other physical) constraints. The efficient dispatch algorithms used in this process, in combination with the bidding rules, imply that the spot price of electricity under typical conditions and in a perfectly competitive market is determined by the marginal cost of the last unit of energy dispatched (Joskow 2006). Hence, the spot price is determined by the realized random demand and supply.

Because we focus on long-term capacity decisions and not on the market's structure, it is beyond the scope of this paper to model details of the dynamic competitive bidding process. Instead we present a stylized model of such a process that captures the essential features of the bidding *outcomes*. In our model, if the total demand is less than the available wind capacity, then the electricity price is equal to the marginal cost of wind electricity generation (in our case, zero). If realized demand is more than the available wind capacity but still less than the total capacity of wind plus gas, then the spot price is equal to the marginal cost U_G of gas electricity generation. Finally, if demand exceeds the total available capacity then the price jumps to C. Each generator earns positive margin only when the realized demand exceeds its own capacity in the dispatch order. The expected margin is used to cover the investment cost of each technology. Given this background, the spot price $\tilde{p}_s$ in our competition model can be formalized as follows:

$$\tilde{p}_s = \begin{cases} 0 & \text{if } \tilde{D} \leq \tilde{v}_W k_W, \\ U_G & \text{if } \tilde{v}_W k_W < \tilde{D} \leq \tilde{v}_W k_W + k_G, \\ C & \text{if } \tilde{v}_W k_W + k_G < \tilde{D}. \end{cases} \tag{4}$$

Two assumptions should be noted in this price model. First, we assume that the electricity demand is perfectly inelastic and therefore unaffected by the price level. This assumption is fairly realistic, according to results reported in empirical studies of electricity markets; for example, "on a typical US network, 98+% of peak demand is effectively price inelastic in the time frame that system operates" (Joskow 2006). Second, we focus on competition in electricity *generation* and not on competition in electricity *retailing*. Although competition in the spot electricity markets is now widespread, the scope of retail competition is more restricted and thus its results are less certain (Defeuilley 2009). This is why, in the price model (4), it is only the demand of the single retailer $\tilde{D}$ that determines the price. Yet, the model remains valid if there is extra demand D_0 with little variability in the market that is served by other retailers, affecting the spot price. Indeed one can view D_0 as a constant demand that is met by base-load technologies (e.g., nuclear or coal) and $\tilde{D}$ as the shoulder and peak demand (i.e., in addition to the base load) that is met by a single retailer.

5.2. The Capacity Game

Under market competition, the wind generator chooses capacity to maximize its own profit:

$$\max_{k_W} \ \mathbb{E}_{\tilde{D}}\mathbb{E}_{\tilde{v}_W}\{\tilde{p}_s \min(\tilde{D}, \tilde{v}k_W)\} - \alpha_W k_W; \tag{5}$$

the analogous gas generator's problem is

$$\max_{k_G} \ \mathbb{E}_{\tilde{D}}\mathbb{E}_{\tilde{v}_W}\{\tilde{p}_s \min(\tilde{D} - \tilde{v}k_W, k_G)^+\} - \alpha_G k_G. \tag{6}$$

Proposition 4 characterizes the Nash equilibrium (NE) of the capacity game.

Proposition 4. *Assume that $\tilde{D}$ has an IFR distribution. (a) The Nash equilibrium capacity levels (k_W^{NE}, k_G^{NE}) exist, are unique, and are found from the following set of simultaneous equations:*

$$\begin{aligned} q\bar{F}(k_W + k_G)(1 - k_G\phi(k_W + k_G)) + (1-q)\bar{F}(k_G)(1 - k_G\phi(k_G)) &= A_G, \\ \left(1 - \frac{U_G}{C}\right)\bar{F}(k_W + k_G)(1 - k_W\phi(k_W + k_G)) + \frac{U_G}{C}\bar{F}(k_W)(1 - k_W\phi(k_W)) &= A_W. \end{aligned} \tag{7}$$

(b) $k_W^{NE} \gtreqless k_G^{NE}$ if $A_W \lesseqgtr A_G$ and $q \gtreqless 1 - U_G/C$. (c) The total installed capacity under competition is less than under the vertically integrated case; furthermore, if $e > 1$ then the total emission under competition is higher than in the vertically integrated case.

Existence and uniqueness of the pure strategy Nash equilibrium is guaranteed if the demand distribution has increasing failure rate. A comparison between the system of equations (7) that characterizes our solution to the capacity game and the system of equations (3) that characterizes our solution to the vertically integrated case reveals that they follow the same structure—except that, with competition, the hazard rate of the demand distribution enters the picture. Similarly to the vertically integrated case, part (b) of the proposition confirms the importance of the critical ratio in assessing the relative merits of each technology. So under competition as well, investment will be higher for the technology with lower critical ratio, not with lower total average cost.

Part (c) of Proposition 4 states that the total installed capacity under the vertically integrated case is higher than under competition. As a consequence, the greater expense of a backup option allows us to conclude that the total cost of the system is higher under competition (as are total emissions if $e > 1$).

The explanation for this observed effect lies in the market pricing mechanism. Recall that both wind and gas suppliers are paid the highest price only when they run out of capacity. For instance, if demand never exceeds wind capacity then the wind supplier always receives zero payment (its marginal cost). This pricing mechanism creates a direct incentive for both suppliers to invest in less capacity and to increase thereby the likelihood of demand exceeding it.

This result is consistent with several recent studies in electricity markets showing that, under competition, new capacity investments can decline and the system's total cost can increase. For instance, Michaels (2004) reviews a large body of research on the economics of vertical unbundling and concludes (in the US context) that "it remains unclear why restructuring acquired a critical mass of support as quickly as it did in most states. Many may have been blinded to its potential costs by an understandable dissatisfaction with regulation."[11] Although our stylized model does not capture all elements of market competition for electricity, our findings on inefficient investment under competition and on marginal cost pool operations are in line with real-world practices and with more detailed models of electricity markets.

Which technology is hurt more by the move to competition? An analytical response to this question is complicated by the interaction between capacities and their impact on the spot price. However, we can address this question numerically using real-world data; see Figure 4. When we compare panels (a) and (c) of this figure, it seems clear that under competition the wind technology's portfolio share is lower (resp., higher) when it has a lower (resp., higher) capacity. So it is interesting that, when wind has higher capacity than gas (because of a low emission price and hence a low critical ratio), it is hurt more under competition than under vertical integration. The intuition behind this is that the incentive of each generator to underinvest in the competition scenario depends not only on its unit total cost but also on the market price. A higher carbon price increases the unit cost of gas-generated electricity, which under competition creates a disincentive for the gas generator to invest. Similarly, the intermittency of wind generation creates a disincentive for the wind generator to invest under competition. The reason is that, by (4), the spot price

[11] Market liberalization and regulation go hand in hand, of course, but regulation that is inappropriate or rigid can lead to trouble. The most famous example of this was the California electricity crisis in 2001. The electricity market in California opened in April 2000. By June 2000, the spot price for electricity was twice as high as in any month since the market opened—even as regulated retail prices remained fixed. By March 2001, the spread became so wide that the state's largest utility declared bankruptcy. California was forced to take over guarantees for power purchases by the state's three major distribution companies, spending $1 billion each month during the spring of 2001 to meet electricity demand. Beyond these regulatory problems of market values vastly exceeding end-user prices, other factors contributing to the California crisis included the format of the state's wholesale auctions, the manner in which generating capacity was priced, and local sources of market power among transmission-constrained generators (Borenstein 2002).

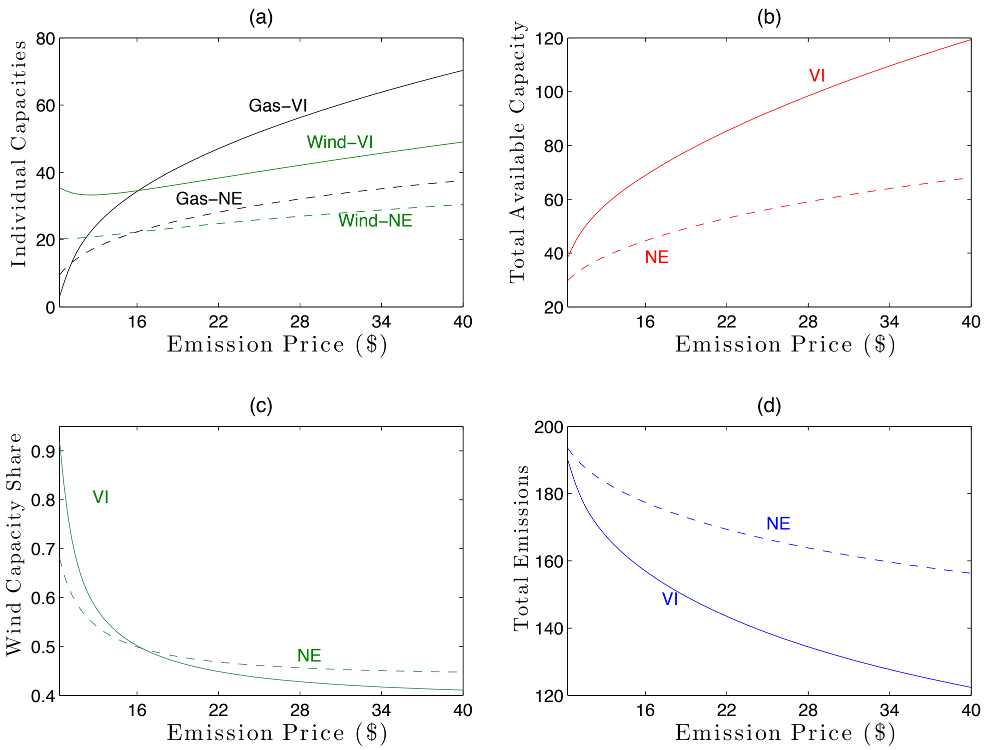

Figure 4 **(a) Individual capacities, (b) total available capacity $qk_W^{\mathsf{NE}} + k_G^{\mathsf{NE}}$, (c) share of wind capacity $k_W^{\mathsf{NE}}/(k_G^{\mathsf{NE}} + k_W^{\mathsf{NE}})$, and (d) total emissions as a function of the emission price under vertical integration (VI) and a competitive Nash equilibrium (NE); here the data are as in Figure 3.**

of electricity is decreasing in the availability of wind capacity; this puts wind at a significant competitive disadvantage, since the price is lowest when wind is available and is highest when wind is not available. Thus we observe in Figure 4(c) that, for $a \leq 18$ (which spans the current carbon price of $a \approx 10$), the share of wind capacity is lower under competition than under vertical integration; in other words, the spot-price disadvantage of wind dominates. This disadvantage fades as carbon prices rise and the gas generator significantly benefits from underinvestment in the competition setting, which enables the share of wind capacity to exceed its share under vertical integration.

Finally, we note with reference to panels (b) and (d) of Figure 4 that the increase in total capacity and decrease in total emissions following a higher carbon price occurs more rapidly under vertical integration than under competition. In other words, increasing the carbon price is less effective at reducing carbon emissions under competition. This result is due mainly to underinvestment incentives stemming from vertical unbundling and its effect on the spot price. In the competitive scenario, higher carbon prices lead to generators benefitting more from underinvestment. This is because the backup technology is more carbon intensive and its total cost is rapidly increasing in the carbon price. Hence generators whose capacity is exceeded will benefit more when the carbon price is high, which in that case incentivizes them to underinvest.

This section has demonstrated the adverse effect of market competition on capacity investment in electricity generation technologies. A common solution that is proposed in related studies is long-term capacity contracts to ensure sufficient capacity investments. This subject is discussed in the next section.

6. Fixed Price Contracts

Here we consider a partially liberalized market in which the retailer signs a long-term fixed-price (FP) contract with the electricity generator. Given the volatility of spot prices, bilateral forward contracts between retailers and generators play a significant role in almost all electricity markets today.[12] The time horizon of the forward contracts can range from a single day to 15–20 years. Short-term forward contracts are typically signed a day ahead and specify the committed capacity and the agreed-upon price. In the United States, long-term forward contracts have been advocated as a means to promote investment in renewable generation capacity and to "spur the growth of renewable generation" (Wilson et al. 2005). In a number of states (including Massachusetts, Rhode Island, New Jersey, and Delaware), the legal instruments are already in place to sign long-term power purchase agreements with fixed prices and with contracting horizons of 10–25 years. Germany and Spain, the two European countries with highest installed capacity for renewable energy, have used long-term FP contracts to promote renewable energy investments. As before, we start with a single-technology benchmark to understand the basic effects of fixed-price contracts and only then address the case of two technologies, where FP forward contracts are signed to promote investment in renewable capacity.

6.1. Benchmark Case: One Technology

For an announced fixed price p_i, the generator's problem is choosing k_i ($i \in \{W, G\}$) to maximize its expected profit:

$$\max_{k_i} \quad \Pi_i(k_i, p_i) = \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \{(p_i - U_i) \min(\tilde{D}, \tilde{v}_i k_i)\} - \alpha_i k_i. \tag{8}$$

The retailer seeks to minimize the total cost of the system by choosing p_i, given that the supplier solves (8):

$$\begin{aligned} \min_{p_i} \quad & \Pi_R(k_i) = \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \{p_i \min(\tilde{D}, \tilde{v}_i k_i) + C(\tilde{D} - \tilde{v}_i k_i)^+\} \\ \text{s.t.} \quad & k_i = \arg\max_{k_i} \Pi_i(k_i, p_i). \end{aligned} \tag{9}$$

[12] Such a bilateral arrangement takes one of two possible forms Borenstein (2002). In an electricity pool, or market based bilateral contracts, all generators sell to a pool run by an independent system operator and all retailers buy from that pool. In this case, the system operator manages the physical feasibility of electricity flow in the network. An alternative to this arrangement is buyers and sellers making their own arrangements for electricity purchase and then informing the system operator about those arrangements. The system operator steps in only if some physical infeasibility might otherwise occur—as when a part of the transmission grid is overloaded. In that case the operator sets grid usage charges to balance the network.

Let $\varepsilon_i = (k_i^{\mathrm{VI}} - k_i^{\mathrm{FP}})/k^{\mathrm{VI}}$ represent the inefficiency that arises from contracting.

PROPOSITION 5. *Suppose the distribution of demand has IFR. (a) There exist unique prices* p_i^* $(i \in \{W, G\})$ *and capacities* k_i^{FP} $(i \in \{G, B\})$ *that solve* (9) *and are characterized as follows:*

$$
\begin{aligned}
p_i^* = U_i + \frac{A_i}{\bar{F}(k_i^{FP})}, \quad \textit{where } k_i^{FP} \textit{ solves} \\
L(k, A_i) = A_i \phi(k) \left(\frac{\int_0^k x f(x)\, dx}{\bar{F}(k)} + k \right) + A_i - \bar{F}(k) = 0.
\end{aligned}
\tag{10}
$$

(b) $k_G^{FP} \geq k_W^{FP}$ *if and only if* $A_G \leq A_W$. *(c)* k_W^{FP} *is increasing in a, and* k_G^{FP} *is increasing in a if and only if* $e > 1$. *(d) Regardless of the technology type, firms always underinvest in the fixed-price contract setting at the optimal solution* (10). *Moreover,* $\varepsilon_W \geq \varepsilon_G$ *if and only if* $A_W \geq A_G$.

This proposition states that the optimal fixed price for a long-term contract between generator and retailer is calculated as the total unit variable cost of generating electricity with technology i *plus* a markup that is a function of i's critical ratio. That markup need not be increasing in the critical ratio A_i, since the optimal capacity k_i^{FP} is decreasing in A_i and so the numerator and denominator of the markup fraction $A_i/\bar{F}(k_i^{\mathrm{FP}})$ move in the same direction.

Much as in the settings of vertical integration and competition, in this contract setting the driver of technology advantage is the critical ratio A_i. The reason is that the backup cost is reflected in the contract price, which determines the capacity decisions made by the generators. As a result, all of the comparative static results described previously for A_i still apply. In particular, part (c) of Proposition 5 states that the optimal wind capacity is always increasing in the carbon price but that gas capacity is increasing in the carbon price only when it emits less carbon than the backup technology (although, as mentioned before, this is usually the case). Section 6.2 shows that—because of the substitution effect—this result may not hold when there is simultaneous investment in two technologies.

Finally, Proposition 5 states that the vertical separation of retailer and generator in the setting of a fixed-price contract leads to an inefficiency in the form of underinvestment in capacity, $\varepsilon_i \geq 0$. Moreover, that inefficiency is greater for the technology with the higher critical ratio (and thus the lower capacity investment) because this technology can be more efficiently substituted for the backup generation. In the next section we show that this is not the case when both technologies are present because one of them will have a comparative advantage.

6.2. Partial Market Competition with Long-Term Fixed-Price Contracts for the Wind Generator

We now consider the case where the retailer enters into a long-term fixed-price contract with the wind generator but the price for the gas generator is still determined through a spot-market mechanism similar to the one described in Section 5. Based on the contracted fixed price, the *wind* generator decides what level of wind capacity to install. This decision, in turn, affects the spot price by shifting the demand curve and thereby influencing the *gas* generator's decision regarding what level of capacity to install. Thus the level of installed capacity for gas technology does depend (albeit indirectly) on the fixed price set by the retailer for the wind technology, so in this sense the two suppliers compete in the market. The retailer's objective is to choose the price for wind electricity such that its own total cost is minimized:

$$\min_{p_W} \ \mathbb{E}_{\tilde{v}_i}\mathbb{E}_{\tilde{D}}\{p_W \min(\tilde{D}, \tilde{v}k_W) + \tilde{p}_s \min(\tilde{D} - \tilde{v}k_W, k_G)^+\}. \tag{11}$$

The wind generator decides on the amount of capacity to install based on the retailer's announced price for wind electricity,

$$\max_{k_W} \ \Pi_W(k_W) = \mathbb{E}_{\tilde{v}_i}\mathbb{E}_{\tilde{D}}\{p_W \min(\tilde{D}, \tilde{v}k_W)\} - \alpha_W k_W, \tag{12}$$

and the gas generator's problem is formulated as

$$\max_{k_G} \ \Pi_G(k_G) = \mathbb{E}_{\tilde{v}_i}\mathbb{E}_{\tilde{D}}\{(\tilde{p}_s - U_G)\min(\tilde{D} - \tilde{v}k_W, k_G)^+\} - \alpha_G k_G. \tag{13}$$

The complexity of the relation between contracted capacity and the gas generator's problem precludes our establishing analytically the concavity of the retailer's objective function. The first-order conditions are characterized in the Appendix and are, indeed, similar to those for Proposition 5. We use these conditions to obtain the optimal solutions in Figure 5, which illustrates the solution in the FP case as well as in the cases of vertical integration and market competition, as before using the real data. In line with the results from Section 6.1, we observe that fixed-price contracts decrease investment for both technologies relative to the vertically integrated case. Also, as one would expect, FP contracts increase the installed wind capacity and decrease the gas capacity relative to the case of market competition. This is because the wind generator now has the clear advantage of no uncertainty in prices. Somewhat surprisingly, however, there is little difference in gas capacity investment between the FP and NE cases. Hence we observe more total installed capacity in the contracting than in the market competition case, where most of the increased generation capacity now comes from wind.

Although the overall increase in wind capacity under a regime of fixed-price contracts is good news, there is no free lunch: the increase in wind and total capacity is such that emissions in this setting remain higher than under vertical integration. The reason is that the installed gas capacity in this case is insufficient to provide backup for the intermittent wind capacity, forcing the retailer to employ the emission-intensive backup option. In short, fixed-price contracts are successful at promoting renewables but fail to abate emissions relative to the case of market competition. Of course, these statements hold only for relatively high shares of renewable electricity generation capacity.

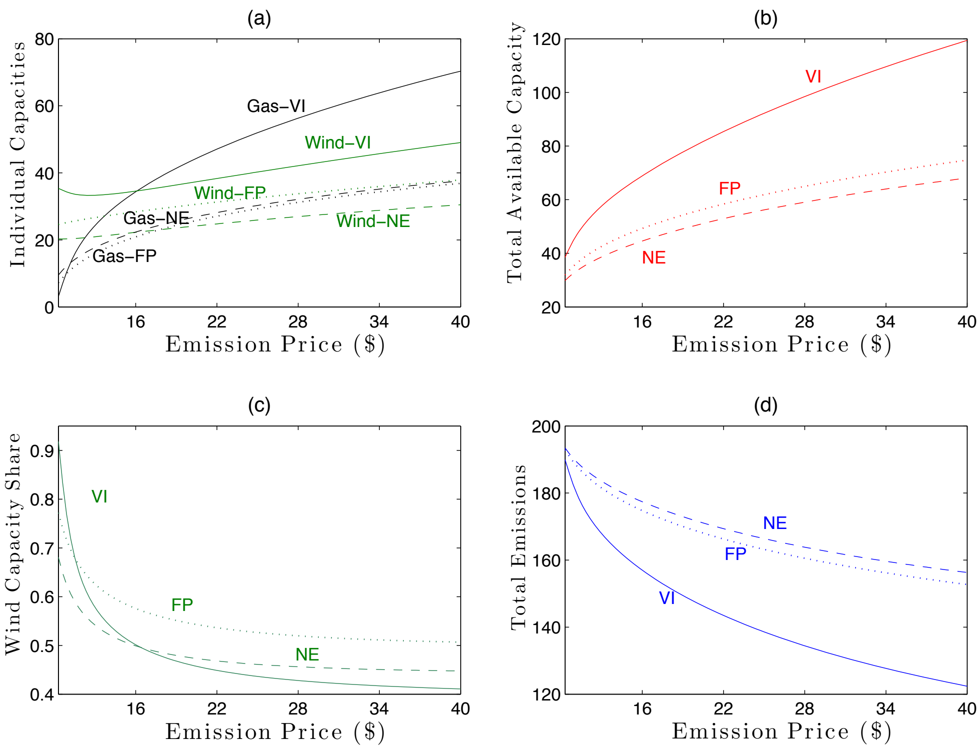

Figure 5 **(a) Individual capacities, (b) total available capacity $qk_W^{\mathsf{FP}} + k_G^{\mathsf{FP}}$, (c) share of wind capacity $k_W^{\mathsf{FP}}/(k_G^{\mathsf{FP}} + k_W^{\mathsf{FP}})$, and (d) total emissions as a function of the emission price under vertical integration (VI), a competitive Nash equilibrium (NE), and a partially liberalized market with fixed-price contracts (FP); here the data are as in Figure 3.**

7. Conclusions

In this paper we study the effect of two recent developments in the electricity markets: liberalization and the introduction of renewables. Using a novel approach in this context, we analyze how the intermittency of renewables links these two changes in the electricity industry. In particular, we demonstrate direct relationships among cost structure, intermittency, and capacity investments; in so doing, we establish an important yet largely overlooked link between the intermittency of renewable energy sources and the effectiveness of renewable-promoting policies such as carbon pricing. We demonstrate that, even though renewables become more cost competitive on average as the carbon price increases, higher carbon prices may actually decrease the share of renewable capacity in the overall generation portfolio—in both the vertically integrated and the (partially) liberalized market. Thus, although increasing the price of carbon emissions does lead to lower total emissions, this policy is not a good way to promote investment in renewables. Moreover, we show that market liberalization may not promote efficient investment in generation capacity. Liberalization also leads to an increase in total emissions from the generation portfolio, and for a reasonable range of carbon prices it leads to a lower share of renewables than in the vertically integrated case. The root cause of this effect is the interaction between intermittency and market pricing.

We further show that long-term electricity contracts, which offer fixed feed-in tariffs to the owners of renewable generation capacity, do ameliorate some disadvantages of the liberalized markets. Namely, they lead to a significant increase in renewable capacity investment while not appreciably affecting nonrenewable capacities. Thus long-term contracts with renewable generators increase the total installed capacity and reduce emissions relative to the market competition case. We conclude that long-term fixed-price contracts are a good means of compensating for the disadvantages of market liberalization from the viewpoints of total cost and greenness both. However, these contracts could also lead to dramatic overinvestment in renewables and underinvestment in gas generation (relative to the vertically integrated case) for high enough carbon prices. The likely result would be an overreliance on the backup (coal-fired) generators; besides being detrimental to the environment, this could also lead to grid-balancing issues if the need arises for significant backup generation.

Overall, our analysis indicates that the intermittency of renewable energy sources is a problematic feature that handicaps investment decisions in these technologies. Although raising carbon taxes is meant to improve the attractiveness of renewables, we show that this is probably not an effective policy. A more effective approach to increasing capacity investment in renewables would be to reduce intermittency. There are various options to achieve this goal. The first option is storage, for which various (relatively new technologies) are available.[13] These technologies include pumped-storage hydropower, which stores electricity in the form of potential energy, and pumped heat electricity storage, which uses argon gas to store power in the form of heat. There are many recent papers that consider the problem of optimal storage policies while taking installed generation capacity as fixed (for a comprehensive review, see Faghih et al. 2012). Other options besides storage include the "curtailing" of intermittent generation (as described in Wu and Kapuscinski 2012) and the pooling of multiple generation units (possibly with different technologies) whose supply is not perfectly correlated. This latter approach may be possible only for large generators with enough resources to invest in multiple wind farms in different geographical regions. So even though there are no economies of scale in wind electricity generation, clearly there are statistical economies of scale in terms of reduced intermittency. Our analysis is a first step toward further research on an integrated framework that will combine these solutions with an explanation of how long-run capacity decisions are affected by the cost structure of renewables. Our results suggest the possibility of additional value to these solutions if generation capacity decisions are taken into account.

[13] See an *Economist* article on this topic at `http://www.economist.com/node/21548495`.

In this paper we have refrained from modeling multiple generating firms each with multiple technologies, which would have allowed a more realistic presentation. Extending our model along such lines would require modeling a complex bidding process that involves many firms and several technologies—an analytically challenging task. Another limitation of this study is that we focused on just two technology types, although other electricity generation technologies may have strongly different features. For instance, nuclear and large-scale coal generators have no intermittency problems, but neither do they have any flexibility in adjusting output. Future research may consider these and other extensions of the long-term capacity investment problem.

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Appendix: Proofs

Proof of Proposition 1. (a) Define

$$\bar{\Pi}(k;\alpha,q,u) = \mathbb{E}_{\tilde{D}}\big\{q\big(u\min(\tilde{D},k) + C(\tilde{D}-k)^+\big) + (1-q)C\tilde{D}\big\} + \alpha k. \tag{14}$$

It is straightforward to verify that $\bar{\Pi}_W(k_W) = \bar{\Pi}(k_W;\alpha_W,q,0)$ and $\bar{\Pi}_G(k_G) = \bar{\Pi}(k_G;\alpha_G,1,U_G)$. So solving problem (1) requires only that we characterize the solution to $\min_k \Pi(k;\alpha,q,u)$. Equation (14) can be equivalently written as

$$\bar{\Pi}(k;\alpha,q,u) = q\left(u\left(\int_0^k xf(x)\,dx + \int_k^\infty kf(x)\,dx\right) + c\int_k^\infty (x-k)f(x)\,dx\right)$$

$$+(1-q)c\mathbb{E}\{\tilde{D}\}+\alpha k. \tag{15}$$

We write the first-order condition (FOC) as

$$\frac{\partial}{\partial k}\bar{\Pi}(k;\alpha,q,u)=-q(c-u)(\bar{F}(k))+\alpha=0 \tag{16}$$

or, equivalently, $\bar{F}(k)=\frac{\alpha}{q(c-u)}=A(\alpha,q,u)$. The rest follows from the definition of A_W and A_G. For $c>u$, we have $\frac{\partial^2}{\partial k^2}\bar{\Pi}(k;\alpha,q,u)=q(c-u)f(k)>0$ and so the FOC is sufficient.

(b) The result follows immediately from part (a) of Proposition 1 after considering that $A_i>0$ and $\bar{F}(k)$ is decreasing.

(c) The result follows immediately from part (a) of Proposition 1 once we verify that A_W is always decreasing in a and that A_W is decreasing in a if and only if $e>1$.

Proof of Proposition 2. (a) We rewrite (2) as:

$$\begin{aligned}\bar{\Pi}(k_W,k_G)=q\bigg(&\int_{k_W}^{k_W+k_G}U_G(x-k_W)f(x)\,dx\bigg)\\&+\int_{k_W+k_G}^{\infty}(U_Gk_G+c(x-k_W-k_G))f(x)\,dx\\&+(1-q)\int_0^{k_G}U_Gxf(x)\,dx\\&+\int_{k_G}^{\infty}(U_Gk_G+C(d-k_G))f(x)\,dx+\alpha_Wk_W+\alpha_Gk_G.\end{aligned} \tag{17}$$

First we verify that $\bar{\Pi}(k_W,k_G)$ is jointly convex. Calculating the Hessian matrix yields

$$H=\begin{pmatrix}\frac{\partial^2\Pi}{\partial k_W^2} & \frac{\partial^2\Pi}{\partial k_W\partial k_G}\\ \frac{\partial^2\Pi}{\partial k_W\partial k_G} & \frac{\partial^2\Pi}{\partial k_G^2}\end{pmatrix}, \tag{18}$$

where

$$\begin{aligned}\frac{\partial^2\Pi}{\partial k_W^2}&=q\big(U_Gf(k_W)+(C-U_G)f(k_W+k_G)\big)>0,\\ \frac{\partial^2\Pi}{\partial k_G^2}&=(C-U_G)\big(qf(k_W+k_G)+(1-q)f(k_G)\big)>0,\\ \frac{\partial^2\Pi}{\partial k_W\partial k_G}&=q(C-U_G)f(k_W+k_G)>0,\end{aligned}$$

and $|H|=Cq\Big(\big(qU_Gf(k_W)+(1-q)Cf(k_G)\big)f(k_W+k_G)+U_G(1-q)f(k_W)f(k_G)\Big)>0$. Therefore, H is a positive definite matrix; this implies that $\bar{\Pi}(k_W,k_G)$ is jointly convex in its arguments and hence that the FOCs are sufficient. Writing the FOCs with respect to k_W and k_G, we obtain

$$-q\bigg(U_G\int_{k_W}^{k_W+k_G}f(x)\,dx+C\int_{k_W+k_G}^{\infty}f(x)\,dx\bigg)+\alpha_W=0, \tag{19}$$

$$-(C-U_G)\left(q\int_{k_W+k_G}^{\infty} f(x)\,dx+(1-q)\int_{k_G}^{\infty} f(x)\,dx\right)+\alpha_G=0; \tag{20}$$

after some simplification and substitution, this yields the system of equations identified in Proposition 2.

Furthermore, $\Pi(k_W,k_G)$ is supermodular in its arguments (see Vives 2001, Thm. 2.3):

$$\frac{\partial^2\Pi}{\partial k_W\partial k_G}=q(C-U_G)f(k_W+k_G)>0, \tag{21}$$

so the technologies are substitutes.

(b) If $A_W\le A_G$ and $q\ge 1-\frac{U_G}{C}$, then

$$\begin{aligned}
&q\bar F(k_W^{\mathrm{VI}}+k_G^{\mathrm{VI}})+(1-q)\bar F(k_W^{\mathrm{VI}})\\
\le&\left(1-\frac{U_G}{C}\right)\bar F(k_W^{\mathrm{VI}}+k_G^{\mathrm{VI}})+\frac{U_G}{C}\bar F(k_W^{\mathrm{VI}})\quad\left(\text{because } q\ge 1-\frac{U_G}{C} \text{ and } \bar F(k_W^{\mathrm{VI}}+k_G^{\mathrm{VI}})\le F(k_W^{\mathrm{VI}})\right)\\
&\le q\bar F(k_W^{\mathrm{VI}}+k_G)+(1-q)\bar F(k_G^{\mathrm{VI}})\quad(\text{ because } A_W\le A_G)\\
&\Longrightarrow \bar F(k_W^{\mathrm{VI}})\le \bar F(k_G^{\mathrm{VI}})\Longrightarrow k_W^{\mathrm{NE}}\ge k_G^{\mathrm{NE}}.
\end{aligned}$$

The converse case is proved analogously.

Parts (c) and (d) of the proposition are similarly obtained by using monotone comparative statics to verify that $\Pi(k_W,k_G;q,u_G,\alpha_W,\alpha_G)$ has increasing (or decreasing) differences in the following parameters:

$$\begin{aligned}
\frac{\partial^2}{\partial k_W\partial q}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=-\int_{k_W}^{k_W+k_G}U_Gf(x)\,dx-\int_{k_W+k_G}^{\infty}Cf(x)\,dx\le 0,\\
\frac{\partial^2}{\partial k_W\partial u_G}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=-q\int_{k_W}^{k_W+k_G}f(x)\,dx\le 0,\\
\frac{\partial^2}{\partial k_W\partial \alpha_W}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=1>0,\\
\frac{\partial^2}{\partial k_W\partial \alpha_G}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=0,\\
\frac{\partial^2}{\partial k_G\partial q}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=(C-U_2)\left(\int_{k_G}^{\infty}f(x)\,dx-\int_{k_W+k_G}^{\infty}f(x)\,dx\right)\ge 0,\\
\frac{\partial^2}{\partial k_G\partial u_G}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=q\int_{k_W+k_G}^{\infty}f(x)\,dx+(1-q)\int_{k_G}^{\infty}f(x)\,dx\ge 0,\\
\frac{\partial^2}{\partial k_G\partial \alpha_W}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=0,\\
\frac{\partial^2}{\partial k_G\partial \alpha_G}\Pi(k_W,k_G;q,U_G,\alpha_W,\alpha_G)&=1>0.
\end{aligned}$$

Proof of Proposition 3. (a) The general rule for implicit derivatives implies that

$$\begin{pmatrix}\frac{\partial k_W^{\mathrm{VI}}}{\partial c}\\ \frac{\partial k_W^{\mathrm{VI}}}{\partial c}\end{pmatrix}=H^{-1}\cdot\begin{pmatrix}\frac{\partial^2\Pi}{\partial k_W\partial c}\\ \frac{\partial^2\Pi}{\partial k_G\partial c}\end{pmatrix}, \tag{22}$$

where H^{-1} is the inverse of the Hessian matrix defined in the proof of Proposition 2. We calculate the partial derivatives and obtain

$$\frac{\partial^2 \Pi}{\partial k_W \partial c} = -q \int_{k_W+k_G}^{M} f(d)\,dd,$$
$$\frac{\partial^2 \Pi}{\partial k_G \partial c} = -\left(q \int_{k_W+k_G}^{M} f(d)\,dd + (1-q)\int_{k_G}^{M} f(d)\,dd\right).$$

Substituting these values into (22) and then applying Cramer's rule, we obtain

$$\begin{pmatrix} \frac{\partial k_W^{\mathrm{VI}}}{\partial c} \\ \frac{\partial k_G^{\mathrm{VI}}}{\partial c} \end{pmatrix} = \frac{1}{|H|}\begin{pmatrix} (C-U_G)q(1-q)\big(-f(k_W+k_G)\bar{F}(k_G)+\bar{F}(k_W+k_G)f(k_G)\big) \\ q\Big(q\bar{F}(k_W+k_G)U_G f(k_W)+(1-q)\bar{F}(k_G)\big(u_G f(k_W)+(C-U_G)f(k_W+k_G)\big)\Big) \end{pmatrix}, \tag{23}$$

where $|H|>0$ is the determinant of the Hessian matrix. We observe in (23) that $\frac{\partial k_G^{\mathrm{VI}}}{\partial c} \geq 0$ and that if F has IFR then $\frac{f(k_G)}{\bar{F}(k_G)} \leq \frac{f(k_W+k_G)}{\bar{F}(k_W+k_G)}$, which implies that $\frac{\partial k_W^{\mathrm{VI}}}{\partial c} \leq 0$. Furthermore,

$$\frac{\partial k_W^{\mathrm{VI}}}{\partial c} + \frac{\partial k_G^{\mathrm{VI}}}{\partial c} = \frac{q}{|H|}\big((qu_G f(k_W)+(1-q)Cf(k_G))\bar{F}(k_W+k_G)+(1-q)\bar{F}(k_G)u_G f(k_W)\big)$$
$$\geq 0. \tag{24}$$

(b) We show that if $e \leq 1$ then k_W^{VI} is increasing in a and k_G^{VI} is decreasing in a. Much as in the proof of Proposition 2, we obtain the desired result by first using monotone comparative statics to calculate the cross partial derivatives of $\bar{\Pi}(k_W,k_G;a)$ with respect to (k_W,a) and (k_G,a) and then using that capacities are substitutes. If $e \leq 1$ then

$$\frac{\partial^2}{\partial k_W \partial a} = -q\left(\int_{k_W+k_G}^{\infty} f(x)\,dx + e\int_{k_W+k_G}^{\infty} f(x)\,dx\right) \leq 0 \quad \text{and} \tag{25}$$
$$\frac{\partial^2}{\partial k_G \partial a} = (1-e)\left(q\int_{k_W+k_G}^{\infty} f(x)\,dx + (1-q)\int_{k_G}^{\infty} f(x)\,dx\right) \geq 0. \tag{26}$$

The second part of the proposition is proved by the existence of the counterexample provided in the text.

Proof of Proposition 4. (a) We rewrite the wind generator's profit in (5) as

$$\Pi_W(k_W,k_G) = q\left(U_G k_W \int_{k_W}^{k_W+k_G} f(x)\,dx + Ck_W\int_{k_W+k_G}^{\infty} f(x)\,dx\right) - \alpha_W k_W \tag{27}$$

and rewrite the gas generator's problem in (6) as

$$\Pi_G(k_W,k_G) = qk_G(C-U_G)\int_{k_W+k_G}^{\infty} f(x)\,dx + (1-q)k_G(C-U_G)\int_{k_G}^{\infty} f(x)\,dx - \alpha_G k_G. \tag{28}$$

Now taking the derivatives of $\Pi_W(k_W,k_G)$ with respect to k_W and of $\Pi_G(k_W,k_G)$ with respect to k_G, we find that the Nash equilibrium of the capacity game solves the following system of equations:

$$qU_G\int_{k_W}^{k_W+k_G} f(x)\,dx + qC\int_{k_W+k_G}^{\infty} f(x)\,dx - qk_W(C-U_G)f(k_W+k_G) - qU_G k_W f(k_W) - \alpha_W = 0,$$

$$(C-U_G)\left(q\int_{k_W+k_G}^{\infty} f(x)\,dx+(1-q)\int_{k_G}^{\infty} f(x)\,dx-qk_Gf(k_W+k_G)-k_G(1-q)f(k_G)\right)-\alpha_G=0.$$

If we replace $f(\cdot)$ with $\phi(\cdot)\bar{F}(\cdot)$ then, after some simplification, we obtain that the NE of the capacity game solves the system of equations specified in Proposition 4. Observe that if the demand distribution has IFR—that is, if $\phi(x)$ is increasing—then the left-hand side of each FOC just displayed is strictly decreasing in both arguments. Hence $\Pi_W(k_W,k_G)$ is strictly concave in k_W and $\Pi_G(k_W,k_G)$ is strictly concave in k_G, which implies that the FOCs are sufficient and the NE is unique.

(b) The proof of this part of Proposition 4 is analogous to the proof of Proposition 2(b).

(c) Recall that the optimal capacities for the vertically integrated case solve the system of equations in Proposition 2. Suppose that the total capacity under competition is higher than the first-best case—that is, let $k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}}>k_W^{\mathrm{VI}}+k_G^{\mathrm{VI}}$. Then we should have either $k_G^{\mathrm{VI}}<k_G^{\mathrm{NE}}$ or $k_W^{\mathrm{VI}}<k_W^{\mathrm{NE}}$ (or both). In the first case, $k_G^{\mathrm{VI}}<k_G^{\mathrm{NE}}$, we have

$$\begin{aligned}
A_G &= q\bar{F}(k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}})(1-k_G^{\mathrm{NE}}\phi(k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}}))+(1-q)\bar{F}(k_G^{\mathrm{NE}})(1-k_G^{\mathrm{NE}}\phi(k_G^{\mathrm{NE}}))\\
&< q\bar{F}(k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}})+(1-q)\bar{F}(k_G^{\mathrm{NE}})\\
&< q\bar{F}(k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}})+(1-q)\bar{F}(k_G^{\mathrm{NE}})=A_G,
\end{aligned}$$

which is a contradiction. The other two cases also lead to a contradiction in a similar fashion. We therefore conclude that the inequality $k_W^{\mathrm{NE}}+k_G^{\mathrm{NE}}>k_W^{\mathrm{VI}}+k_G^{\mathrm{VI}}$ can never hold.

It is now straightforward to verify that if $e>1$ then the total emissions of the system is higher under competition.

Proof of Proposition 5. (a) The objective function in (8) for the wind technology may be written as

$$\Pi_W(k_W,p_W)=p_Wq\left(\int_0^{k_W} xf(x)\,dx+\int_{k_W}^{\infty} k_Wf(x)\,dx\right)-k_W\alpha_W \tag{29}$$

and that for gas technology as

$$\Pi_G(k_G,p_G)=(p_G-U_G)\left(\int_0^{k_G} xf(x)\,dx+\int_{k_G}^{\infty} k_Gf(x)\,dx\right)-k_G\alpha_G. \tag{30}$$

We shall prove the case for wind technology; the case for gas technology proceeds along analogous lines. Writing the FOC for problem (30) with respect to k_W, we obtain

$$\frac{\partial\Pi_W(k_W,p_W)}{\partial k_W}=p_Wq\left(\int_{k_W}^{\infty} f(x)\,dx\right)-\alpha_W=p_Wq(\bar{F}(k_W))-\alpha_W=0. \tag{31}$$

We note that $\frac{\partial^2}{\partial k_W^2}\Pi_W(k_W,p_W)=-p_Wqf(k_W)<0$, so the FOC is sufficient. The retailer's problem (9) is then written as

$$\begin{aligned}
&\min_{p_W}\; q\left(p_W\int_0^{k_W} xf(x)\,dx+c\int_{k_W}^{\infty}(x-k_W)f(x)\,dx\right)\\
&\text{s.t. } k_W \text{ solves (31).}
\end{aligned} \tag{32}$$

Because there is a one-to-one relationship between k^* and p^* in (31), problem (32) can be transformed so that the decision variable is k_W. Toward this end, we first solve (31) for p_W to obtain $p_W = \frac{\alpha_W}{q(\bar{F}(k_W))}$. Substituting this into (32) yields the following transformation of the retailer's problem:

$$\min_{k_W} \; q\left(\frac{\alpha_W}{q(\bar{F}(k_W))}\int_0^{k_W} xf(x)\,dx + c\int_{k_W}^{\infty}(x-k_W)f(x)\,dx\right). \tag{33}$$

Writing the FOC for problem (33) and then simplifying, we find that that k^* solves $L_W(k, A_W) = 0$.

It is straightforward to verify that if the demand distribution has IFR then $L(k, A_i)$ is increasing in k because $\int_0^k xf(x)\,dx$ and $F(k)$ are both strictly increasing in k. This state is equivalent to the objective function in (32) being strictly convex in k; hence the FOC is sufficient and the solution to problem (32) is unique.

(b,c) These results follow simply by verifying that $L(k, A_i)$ is increasing in k and A_i; and that A_W is decreasing in a and A_G is decreasing in a if and only if $e > 1$.

(d) By Proposition 1, k_i^{VI} solves $A_i - \bar{F}(k) = 0$; by part (a) of Proposition 5, k_i^* solves $L(k, A_i) = l(A_i, k) + A_i - \bar{F}(k) = 0$, where $l(A_i, k) > 0$ is the first term in $L(k, A_i)$ defined in (10). The first part of the result (underinvestment) follows from considering that both $A_i - \bar{F}(k)$ and $L(k, A_i)$ are increasing and that $L(k, A_i) \geq A_i - \bar{F}(k)$. As for the second part, because $l(A_i, k)$ is increasing in A_i, we conclude that $k_i^{\mathrm{VI}} - k_i^*$ is increasing in A_i. This, along with the fact that k_i^{VI} is decreasing in A_i implies that ε_i is increasing in A_i.

Characterization of the First-Order Conditions in Section 6.2. The following proposition states the necessary conditions for the interior capacity solutions.

Proposition 6. *The interior optimal capacities for wind and gas under a fixed-price contract for the wind generator (i.e., k_W^{FP} and k_G^{FP}) solve the following first-order conditions:*

$$q\bar{F}(k_W + k_G)(1 - k_G\phi(k_W + k_G)) + (1-q)\bar{F}(k_G)(1 - k_G\phi(k_G)) = A_G,$$
$$\left(1 - \frac{U_G}{C}\right)\bar{F}(k_W + k_G)(1 + k_G f(k_W + k_G)) + \frac{U_G}{C}\bar{F}(k_W) = A_W\left(1 + \phi(k_W)\left(k_W + \frac{\int_0^{k_W} xf(x)\,dx}{\bar{F}(k_W)}\right)\right).$$

Proof. The proof is analogous to that of Proposition 5 and is therefore omitted.

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