Is Green Healthy for Competition?
Renewable Technologies, Optimal Generation Mix and Price Volatility in Competitive Electricity Markets

Irena Milstein[a] and Asher Tishler[b]
[a] Holon Institute of Technology, 52 Golomb St., Holon 58102, Israel (irenam@hit.ac.il)
[b] Faculty of Management, Tel Aviv University, Tel Aviv 69978, Israel (atishler@post.tau.ac.il)

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Abstract

This paper develops and solves a two-stage decision model with endogenous generation capacity and electricity production to assess the outlook and practicality of renewable technologies in the electricity sector. We show that a substantial decline in the current construction costs of the PV technology and the adoption of a sizable CO_2 tax are unlikely to significantly affect PV capacity and production. We also show that the average electricity price paid by electricity users is likely to *increase*, and more so when construction costs of PV capacity *decline* (due, say, to technology improvements), yielding excessive profits to electricity producers employing fossil-using technologies. We demonstrate these results by applying the model to real-world data.

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1. Introduction

Generating electricity from renewable energy sources is believed to be one of the main remedies for the fast-increasing problems of greenhouse gases and local air pollution (Weyant, de la Chesnaye and Blanford, 2006; Tol, 2006; Lior, 2010; Cansino et al., 2010, Friedman, 2011).[1] However, research on renewable energy suggests that the road to a "green world" is not yet fully paved and the potential and limits of renewable energy remain insufficiently explored and understood (Trainer, 2010; Lior, 2010; Borenstein, 2011; Blumsack and Fernandez, 2012). It also points out that the high costs of producing electricity from renewable energy will likely raise electricity prices substantially, unless new technologies of electricity generation are developed and adopted (Martinsen et al., 2007; Cansino et al., 2010; Borenstein, 2011; Milstein and Tishler, 2011). Corroborating prior research, this paper demonstrates that integrating renewable energy sources into the electricity sector will indeed be a difficult process, accompanied by higher electricity prices, much higher price volatility and, possibly, fragile competition in the electricity generation market.[2]

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[1] Other means to reduce air pollution and greenhouse gases are, for example, conservation, demand side management, better use of transmission and distribution systems and smart grids. A significant increase in the use of nuclear power in electricity generation is unlikely in the near future (Lior, 2010; Renewables, 2011; Dittmar, 2012; Economist, 2012) and new construction of hydroelectric power is limited to specific countries (Renewables, 2011).

[2] Effective use of renewable energy depends on the tradeoff between the higher cost of electricity from these sources versus the benefits they deliver in abating local pollution and mitigating greenhouse gases (Borenstein, 2011). Thus, research and public policy debates in the coming decade will likely focus on strategies and technologies aimed at increased conservation and on the development of renewable energy to displace the use of fossil fuels (Trainer, 2010; Lior, 2010; Traber and Kemfert, 2009; Solangi et al., 2011).

More specifically, we show that in the foreseeable future the share of PV in total capacity is likely to be small and that a substantial decline in the current construction costs of the PV technology (due, say, to technology improvements) and the adoption of a sizable CO_2 tax are unlikely to significantly affect PV capacity and production.[3] We also show that electricity price spikes will be substantially higher and more frequent in the presence of the PV technology than in its absence and that this phenomenon will be exacerbated by the introduction of CO_2 taxes.[4] Consequently, the average price paid by electricity users will likely *increase*, and more so when construction costs of PV capacity *decline* due to technology improvements, yielding excessive profits to electricity producers employing fossil-using technology (CCGT).[5] Finally, we show that the choice of market structure may significantly affect capacity mix, industry profits, price volatility and consumer welfare.[6]

Our results are derived in the context of a two-stage decision model aimed at disentangling the intricate relationships among the costs of capacity construction and electricity production by fossil-using and renewable technologies, the optimal generation mix, and electricity price level and volatility.[7] We consider two types of

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[3] To simplify the exposition, our model only employs combined cycle gas turbines (CCGT) and PV plants. However, its results apply equally to other fossil as well as weather-dependent renewables such as those deriving from wind, solar-thermal technologies, and sea waves.

[4] A policy aiming to reduce emissions, as is required by the Kyoto protocol (Linares et al., 2006; Cansino et al., 2010).

[5] This somewhat surprising phenomenon is caused by the combination of high electricity price volatility and very low short-term price elasticity of electricity demand.

[6] Substantial price volatility due to sudden and unexpected change in wind generation is reported by ERCOT in Texas (Hardy and Nelson, 2010).

[7] Analysis of demand volatility in electricity markets with renewable energy is not new. See, among others, Holland and Mansur (2008) and Chao (2011).

generating technologies: (1) “regular”, fossil-using, technologies such as combined cycle gas turbines (CCGT) and, (2) weather-dependent renewable technologies in the form of photovoltaic cells (PV). In the first stage of the model (game), when only the probability distribution functions of future daily electricity demands and weather conditions are known, profit-seeking producers maximize their expected profits by determining the capacity to be constructed from each technology. In the second stage, once daily demands and weather conditions become known, each producer selects the daily production levels of each technology subject to its capacity availability (the available capacity of the renewable technology depends on capacity construction in the first stage of the game, and on the weather).[8,9]

The economic process underlying our model is as follows. Electricity production by PV technology will, in the short term, shift production away from fossil-using technologies to PV technology (which features zero marginal cost). In the mid and long term, optimal capacity mix will shift new capacity construction away from CO_2-intensive technologies to PV technology and, possibly, cause early retirement of CO_2-intensive technologies. Finally, an increase in the share of electricity production by PV technology will raise the equilibrium electricity price during periods in which weather conditions limit its use. Since electricity demand is very inelastic in the short run, electricity prices will spike substantially during these

[8] Like many other studies on the electricity sector, we employ the Cournot conjecture to determine equilibrium quantities and prices in the second stage of the game, where electricity is sold simultaneously by all producers to meet market demand (Carpio and Pereira, 2007; Borenstein and Bushnell, 1999; Green, 1996, 2004; Newbery, 1998; Tishler and Woo, 2006; Puller, 2007; Murphy and Smeers, 2005, 2010; Tishler et al., 2008; Bushnell, Mansur and Saravia, 2008).

[9] See Joskow (2011) and Chao (2011) on the difficulty of comparing the cost of production and setting prices of intermittent energy resources.

periods, and will likely raise the average price, granting substantial monopoly power to the electricity producers employing fossil-using technologies.

This paper contributes to the literature by extending the existing models of endogenous investments and operations in electricity markets (Murphy and Smeers, 2005, 2010; Milstein and Tishler, 2012) to include demand *and* supply uncertainties.[10] In particular, we extend the analyses in Chao (2011), Milstein and Tishler (2011) and Joskow (2011) by using formal models which demonstrate the difficulties in pricing energy resources that are available only intermittently, depending on the presence or absence of the sun. Since the marginal costs of the PV technology are zero, PV becomes the "base" technology and will always be used when the sun is shining (up to its maximal capacity or up to the maximal demand), whereas the CCGT technology reverts to the role of the "peaking" technology.[11] Hence, the optimal solution is very sensitive to the sunshine-dependent availability of the PV technology and its capital cost. These properties of the model are illustrated using data for the Israeli electricity market.[12]

This paper is organized as follows. Section 2 develops the model for a market in which each firm can employ only one generation technology (PV or CCGT), and

[10] Although the analysis becomes more complicated, it is straightforward to demonstrate that the nature of the solution is unchanged when more generating technologies are added (Milstein and Tishler, 2011, 2012). See Fan, Norman and Patt (2012) on the effects of uncertainties about the cost of electricity production and about the enactment of an allowance trading system in a market with two fossil-fuel technologies and one renewable technology.

[11] This observation is not new. See, for example, Fan et al. (2012).

[12] Milstein and Tishler (2012) present recent data on four major electricity markets in the USA (New England; California; PJM; and ERCOT), demonstrating that the characteristics of the distribution of electricity demand over time in these markets is very similar to that in Israel. Thus, the results in this paper will likely apply to those, and other, markets.

Section 3 extends the model to include firms that can produce both PV and CCGT electricity. We characterize the models of Sections 2 and 3 by employing real-world data in Section 4 and present welfare analyses in Section 5. Section 6 concludes.

2. A market with firms employing only one technology

2.1. Set-up

Consider two types of generating technologies: (1) PV, to be denoted **S**, with high capacity cost and zero variable (marginal) cost; and (2) CCGT, to be denoted **G**, which exhibits "low" capacity cost and "high" variable (marginal) cost.[13] The market for electricity consists of *N* identical firms employing technology **S** and *M* identical firms employing technology **G**. Each firm builds generating capacity and then uses it to generate and sell electricity on each day of an operation horizon of *T* days (e.g. *T* = 365 for a 1-year horizon).[14] Let P_t and Q_t denote the electricity price and output on day *t*. Following Wolfram (1999) and Tishler, Milstein and Woo (2008), daily electricity demand is:

$$P_t = a - bQ_t + \varepsilon_t, \tag{1}$$

where $Q_t = \sum_{i=I}^{N} Q_{it}^S + \sum_{j=I}^{M} Q_{jt}^G$ and Q_{it}^S and Q_{jt}^G denote the production on day *t* of the *i*-th firm that uses technology **S** and the *j*-th firm that employs technology **G**, respectively.

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[13] Neither of these two technologies dominates the other. See Chao (1983) and Milstein and Tishler (2012) on this issue.

[14] Electricity demand can be defined for any length of time. It is straightforward, for example, to solve the model for 8760 hours or 17520 half-hours of the year. The model assumes that consumers are informed about electricity prices and can respond, at least to some extent, to electricity price changes.

The parameters $a > 0$ and $b > 0$ are assumed to be known constants. In Eq. (1), ε_t is a random variable accounting for the effect of a random demand factor such as temperature. ε_t is revealed to the electricity producers on day t and the price is determined on each day according to the Cournot conjecture.[15] Only $f(\varepsilon_t)$, the (probability) density function of ε_t, and the probability function of daily sunshine are known to the firms when they choose their capacity.

Following Murphy and Smeers (2005, 2010) and Milstein and Tishler (2011, 2012), the annual production cost of the *i*-th firm (the *j*-th firm) employing technology **S** (technology **G**) and a generator of K_i^S (K_j^G) MW of capacity is:

$$C_i(K_i^S, Q_i^S) = \theta^S K_i^S + c^S Q_i^S \tag{2a}$$

$$C_j(K_j^G, Q_j^G) = \theta^G K_j^G + c^G Q_j^G \tag{2b}$$

where $Q_i^S = \sum_{t=1}^{T} Q_{it}^S$ and $Q_j^G = \sum_{t=1}^{T} Q_{jt}^G$ denote the annual production of electricity by firm i and firm j, respectively. Capacity cost is US\$ θ^S (θ^G) per MW-year and variable (marginal) cost is US\$ c^S (c^G) per MWH for technology **S** (technology **G**). By assumption, technology **G** is more expensive in operations, $c^G >> c^S \cong 0$, and technology **S** is more expensive in capacity, $\theta^S > \theta^G$. The parameters c^S, c^G, θ^S and θ^G are assumed to be known constants.

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[15] Puller (2007) shows that the conduct of the firms in the restructured electricity market in California from April 1998 until late 2000 is consistent with a Cournot pricing game. Bushnell et al. (2008) find that a Cournot competition predicted equilibrium prices that are good approximations for actual electricity prices during the summer of 1999 in three US markets.

The availability of PV capacity on day *t*, *t=1,…,T*, is conditional on whether the sun is shining. We suppose that the sun is shining on day *t* with probability ρ. If the sun is shining on day *t*, all of the PV capacity is available on that day; otherwise the available PV capacity is zero. For expositional simplicity, we assume that the presence of sunshine and ε_t are independent.[16] This assumption reflects our contention that demand is mainly driven by temperature, and much less so by daily cloudiness. Finally, we assume that $E(\varepsilon_t) = 0$, $Var(\varepsilon_t) = \sigma^2$ and $c^S < a + \varepsilon_t$.[17]

The decision process of this two-stage model (game) is as follows:

Stage 1: Each of the *N* + *M* firms decides on its capacity investment, K_i^S or K_j^G, to maximize its expected profits over *T* days, taking the capacities of the other *N+M -1* firms and the probability functions of ε_t and daily sunshine as given.

Stage 2: Once the firms know ε_t and the sunshine condition on day *t*, each firm decides how much electricity to produce (and sell) to maximize its daily operating profit. The firm's decision is based on the Cournot conjecture, treating the quantity produced by the other *N+M -1* firms and the capacity of all *N* + *M* firms as given. This stage is repeated *T* (independent) times.

The game is solved recursively using backward induction. The daily electricity production of each firm is found by solving the second stage of the game. The optimal second-stage solutions (the reaction functions) are then used to determine the expected profit maximizing generation capacities in the first stage.

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[16] The nature of the results is unchanged if these two variables are correlated. Price volatility tends to be higher if they are positively correlated.

[17] If $E(\varepsilon_t) = \mu \neq 0$, we add μ to the constant *a* in expression (1), thus setting $E(\varepsilon_t) = 0$.

2.2. Second-stage equilibrium

The objective of the *i*-th firm (which uses technology **S**) at the second stage of the game is to maximize its operating profits, π_{it}, conditional on ε_t, appearance of the sun, K_i^S ($i = 1,...,N$), K_j^G ($j = 1,...,M$), Q_{kt}^S ($k = 1,...,N\,; k \neq i$), and Q_{jt}^P ($j = 1,...,M$). When the sun is shining, the maximization problem of firm *i* on day *t* is:

$$\begin{aligned} &\max_{Q_{it}^S} \pi_{it} = (P_t - c^S) Q_{it}^S \\ &s.t. \quad Q_{it}^S \leq K_i^S, \quad Q_{it}^S \geq 0, \quad i = 1,...,N \end{aligned} \tag{3}$$

If there is no sun on day *t*, firm *i* does not produce on that day.

The objective of the *j*-th firm (which uses technology **G**) is to maximize its operating profits, π_{jt}, conditional on ε_t, K_i^S ($i = 1,...,N$), K_j^G ($j = 1,...,M$), Q_{it}^S ($i = 1,...,N$), and Q_{lt}^G ($l = 1,...,M\,; l \neq j$). If the sun is shining on day *t*, firm *j* treats the quantity produced by the *N* firms, employing technology **S**, and their capacity as given. If there is no sun on day *t*, firm *j* relates only to the *M-1* firms employing technology **G**. Formally, the maximization problem of firm *j* on day *t* is:

$$\begin{aligned} &\max_{Q_{jt}^G} \pi_{jt} = (P_t - c^G) Q_{jt}^G \\ &s.t. \quad Q_{jt}^G \leq K_j^G, \quad Q_{jt}^G \geq 0, \quad j = 1,...,M \end{aligned} \tag{4}$$

If the sun is shining on day *t*, the equilibrium solution is obtained when the following Karush-Kuhn-Tucker (KKT) conditions for each firm of each type are satisfied simultaneously (conditions (5a) for each firm employing technology **S** and conditions (5b) for each firm employing technology **G**):

$$a - 2bQ_{it}^{S} - b\sum_{k \neq i}^{N} Q_{kt}^{S} - b\sum_{j=1}^{M} Q_{jt}^{G} + \varepsilon_t - c^{S} - \lambda_i^{S} + \mu_i^{S} = 0, \quad \mu_i^{S} Q_{it}^{S} = 0, \quad (K_i^{S} - Q_{it}^{S})\lambda_i^{S} = 0,$$
$$K_i^{S} - Q_{it}^{S} \geq 0, \quad Q_{it}^{S} \geq 0, \quad \lambda_i^{S} \geq 0, \quad \mu_i^{S} \geq 0, \quad i = 1,\ldots,N, \tag{5a}$$

$$a - b\sum_{i=1}^{N} Q_{it}^{S} - 2bQ_{jt}^{G} - b\sum_{l \neq j}^{M} Q_{lt}^{G} + \varepsilon_t - c^{G} - \lambda_j^{G} + \mu_j^{G} = 0, \quad \mu_j^{G} Q_{jt}^{G} = 0, \quad (K_j^{G} - Q_{jt}^{G})\lambda_j^{G} = 0,$$
$$K_j^{G} - Q_{jt}^{G} \geq 0, \quad Q_{jt}^{G} \geq 0, \quad \lambda_j^{G} \geq 0, \quad \mu_j^{G} \geq 0, \quad j = 1,\ldots,M, \tag{5b}$$

where λ_i^S and λ_j^G are the dual variables for the capacity constraint of technology **S** and technology **G**, respectively, and μ_i^S and μ_j^G are the dual variables for the non-negativity of Q_{it}^S and Q_{jt}^G, respectively.

If the sun is *not* shining on day *t*, the equilibrium solution is obtained when the following KKT conditions for each firm employing technology **G** are satisfied:

$$a - 2bQ_{jt}^{G} - b\sum_{l \neq j}^{M} Q_{lt}^{G} + \varepsilon_t - c^{G} - \lambda_j^{G} + \mu_j^{G} = 0, \quad \mu_j^{G} Q_{jt}^{G} = 0, \quad (K_j^{G} - Q_{jt}^{G})\lambda_j^{G} = 0,$$
$$K_j^{G} - Q_{jt}^{G} \geq 0, \quad Q_{jt}^{G} \geq 0, \quad \lambda_j^{G} \geq 0, \quad \mu_j^{G} \geq 0, \quad j = 1,\ldots,M, \tag{6}$$

where λ_j^G is the dual variable for the capacity constraint of technology **G**, and μ_j^G is the dual variable for the non-negativity of Q_{jt}^G.

The solution of (5) is given in Milstein and Tishler (2012)[18] and the solution of (6) is given in Tishler et al. (2008).[19]

[18] See Proposition 1 in Milstein and Tishler (2012), where a base technology, denoted by B, is PV, and a peaking technology, denoted by P, is CCGT.

[19] See Eq. (4) in Tishler et al. (2008).

2.3. First-stage equilibrium conditions

To determine optimal capacities, the *i*-th firm employing technology **S** and the *j*-th firm employing technology **G** use the second-stage reaction functions to solve their expected profit maximization problems at stage 1:

$$\max_{K_i^S} \quad \rho E[\sum_{t=1}^{T}(\pi_{it} \mid K_i^S, K_j^G)] - \theta^S K_i^S, \quad i = 1, ..., N, \tag{7a}$$

$$\max_{K_j^G} \quad \rho E[\sum_{t=1}^{T}(\pi_{jt} \mid K_j^G, K_i^S)] + (1-\rho)E[\sum_{t=1}^{T}(\pi_{jt} \mid K_j^G)] - \theta^G K_j^G, \quad j = 1, ..., M \tag{7b}$$

where expectations are taken over ε_t, $t = 1, ..., T$.

The solution of Eq. (7) cannot be obtained in an explicit form for an arbitrary distribution function of ε_t, $f(\varepsilon_t)$. Following Milstein and Tishler (2012) and Wang et al. (2007), we assume that ε_t is uniformly distributed. That is, $f(\varepsilon_t) = 1/(\beta - \alpha)$, where $\alpha \le \varepsilon_t \le \beta$. The symmetric equilibrium solution (i.e. $K_1^{S*} = ... = K_N^{S*} = K^{S*}$ and $K_1^{G*} = ... = K_M^{G*} = K^{G*}$) is obtained when the following KKT conditions for each type of firm are satisfied simultaneously:[20]

[20] The KKT conditions are built using the proof of Proposition 2 in the Appendix of Milstein and Tishler (2012): the first condition in (8a), (8b), (9a), (9b), (10a), and (10b) follows from Eq. (A16a), (A.16b), (A.29a), (A.29b), (A.44a) and (A.44b), respectively, in Milstein and Tishler (2012). The constraint in the maximization problem stems from using the uniform distribution function. That is, $\beta \ge c^G - a + bK_i^{S*} + bK_{-i}^{S*} + 2bK_j^{G*} + bK_{-J}^{G*}$ in (8)-(9) and $\beta \ge c^G - a + 2bK_i^{S*} + bK_{-i}^{S*} + bK_j^{G*} + bK_{-J}^{G*}$ in (10).

Case (i): When $K^{S*} \le (c^G - c^S)/b$,[21]

$$\rho \cdot \left[[\beta + a - c^S - b(N+1)K^{S*}]^2 - 2bMK^{G*}[\beta + a - c^G - b(N+1)K^{S*}] + b^2 M(M+1)(K^{G*})^2 \right]$$
$$- 2(\beta - \alpha)\theta^S/T - 2(\beta - \alpha)b\lambda^S + 2(\beta - \alpha)\mu^S = 0, \quad \mu^S K^{S*} = 0, \tag{8a}$$
$$\lambda^S \cdot [\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}] = 0, \quad \beta + a - c^G - bNK^{S*} - b(M+1)K^{G*} \ge 0,$$
$$K^{S*} \ge 0, \quad \lambda^S \ge 0, \quad \mu^S \ge 0,$$

$$\rho\left(\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}\right)^2 + (1-\rho)\left(\beta + a - c^G - b(M+1)K^{G*}\right)^2 -$$
$$2(\beta - \alpha)\theta^G/T - 4(\beta - \alpha)b\lambda^G + 2(\beta - \alpha)\mu^G = 0, \quad \mu^G K^{G*} = 0, \tag{8b}$$
$$\lambda^G \cdot [\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}] = 0, \quad \beta + a - c^G - bNK^{S*} - b(M+1)K^{G*} \ge 0,$$
$$K^{G*} \ge 0, \quad \lambda^G \ge 0, \quad \mu^G \ge 0,$$

Case (ii): When $(c^G - c^S)/b < K^{S*} \le (c^G - c^S)/b + K^{G*}$,

$$\rho \cdot \left[[\beta + a - c^S - b(N+1)K^{S*} - bMK^{G*}]^2 + M[(c^G - c^S + bK^{G*})^2 - (bK^{S*})^2] \right] -$$
$$2(\beta - \alpha)\theta^S/T - 2(\beta - \alpha)b\lambda^S + 2(\beta - \alpha)\mu^S = 0, \quad \mu^S K^{S*} = 0, \tag{9a}$$
$$\lambda^S \cdot [\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}] = 0, \quad \beta + a - c^G - bNK^{S*} - b(M+1)K^{G*} \ge 0,$$
$$K^{S*} \ge 0, \quad \lambda^S \ge 0, \quad \mu^S \ge 0,$$

$$\rho\left(\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}\right)^2 + (1-\rho)\left(\beta + a - c^G - b(M+1)K^{G*}\right)^2 -$$
$$2(\beta - \alpha)\theta^G/T - 4(\beta - \alpha)b\lambda^G + 2(\beta - \alpha)\mu^G = 0, \quad \mu^G K^{G*} = 0, \tag{9b}$$
$$\lambda^G \cdot [\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}] = 0, \quad \beta + a - c^G - bNK^{S*} - b(M+1)K^{G*} \ge 0,$$
$$K^{G*} \ge 0, \quad \lambda^G \ge 0, \quad \mu^G \ge 0,$$

Case (iii): When $K^{S*} > (c^G - c^S)/b + K^{G*}$,

$$\rho \cdot [\beta + a - c^S - b(N+1)K^{S*} - bMK^{G*}]^2 - 2(\beta - \alpha)\theta^S/T - 4(\beta - \alpha)b\lambda^S +$$
$$2(\beta - \alpha)\mu^S = 0, \quad \mu^S K^{S*} = 0, \quad \lambda^S \cdot [\beta + a - c^G - b(N+1)K^{S*} - bMK^{G*}] = 0, \tag{10a}$$
$$\beta + a - c^G - b(N+1)K^{S*} - bMK^{G*} \ge 0, \quad K^{S*} \ge 0, \quad \lambda^S \ge 0, \quad \mu^S \ge 0,$$

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[21] These cases correspond to the three possible scenarios at the second stage of the equilibrium. Only firms employing technology **S** produce electricity when daily demand for electricity is "low". When daily demand for electricity is larger, firms employing technology **G** enter production, provided that firms using technology **S** are already at full capacity in case (i), or at less than full capacity in case (ii) or case (iii). Case (ii) applies when firms employing technology **S** reach full capacity before firms employing technology **G** do, whereas in case (iii) firms using technology **G** reach full capacity before firms employing technology **S** do (see Proposition 1 in Milstein and Tishler, 2012).

$$
\begin{aligned}
&\rho \cdot \big[[\beta + a - c^G - bNK^{S*} - b(M+1)K^{G*}]^2 + N[(c^S - c^G + bK^{S*})^2 - (bK^{G*})^2]\big] + \\
&(1-\rho)\big(\beta + a - c^G - b(M+1)K^{G*}\big)^2 - 2(\beta - \alpha)\theta^G / T - 2(\beta - \alpha)b\lambda^G + 2(\beta - \alpha)\mu^G = 0, \\
&\mu^G K^{G*} = 0, \quad \lambda^G \cdot [\beta + a - c^G - b(N+1)K^{S*} - bMK^{G*}] = 0, \\
&\beta + a - c^G - b(N+1)K^{S*} - bMK^{G*} \geq 0, \quad K^{G*} \geq 0, \quad \lambda^G \geq 0, \quad \mu^G \geq 0,
\end{aligned}
\tag{10b}
$$

where λ^S and λ^G are the dual variables for the constraints (stemming from the uniform distribution assumption) for firms employing technology **S** and technology **G**, respectively, and μ^S and μ^G are the dual variables for the non-negativity of K^{S*} and K^{G*}, respectively.

The use of cases (i)-(iii) in numerical analysis is described in the Appendix.

3. A market with firms employing both technologies

In this section we allow each of the $N+M$ firms to build capacity using either PV (**S)** technology or CCGT (**G**) technology or both. Thus, in stage 1 of the game each firm decides on its capacities, taking the capacities of the other $N+M-1$ firms as given. In stage 2 each firm selects its daily output level (using the Cournot conjecture) subject to its capacity availability, thereby determining the equilibrium market prices. We solve the game recursively using backward induction.

Formally, the objective of the *i*-th firm in stage 2 is to maximize its operating profits, π_{it}, conditional on ε_t, appearance of the sun, K_i^S and K_i^G ($i = 1,...,N+M$), Q_{kt}^S and Q_{kt}^G ($k = 1,...,N+M; k \neq i$). When the sun is shining, the maximization problem of firm *i* on day *t* is:

$$
\begin{aligned}
&\max_{Q_{it}^S, Q_{it}^G} \pi_{it} = (P_t - c^S)Q_{it}^S + (P_t - c^G)Q_{it}^G \\
&s.t. \qquad Q_{it}^S \leq K_i^S, \quad Q_{it}^G \leq K_i^G, \quad Q_{it}^S, Q_{it}^G \geq 0, \quad i = 1,...,N+M
\end{aligned}
\tag{11}
$$

When there is no sun, the maximization problem of firm *i* on day *t* is:

$$\max_{Q_{it}^G} \pi_{it} = (P_t - c^G)Q_{it}^G$$
$$s.t. \quad Q_{it}^G \le K_i^G, \quad Q_{it}^G \ge 0, \quad i = 1,\dots,N+M \tag{12}$$

If the sun is shining on day *t*, the KKT conditions for firm *i* are given by:

$$\begin{aligned} & a - 2bQ_{it}^S - b\sum_{k\ne i}^{N+M} Q_{kt}^S - 2bQ_{it}^G - b\sum_{k\ne i}^{N+M} Q_{kt}^G + \varepsilon_t - c^S - \lambda_i^S + \mu_i^S = 0, \quad a - 2bQ_{it}^S - b\sum_{k\ne i}^{N+M} Q_{kt}^S - 2bQ_{it}^G - \\ & b\sum_{k\ne i}^{N+M} Q_{kt}^G + \varepsilon_t - c^G - \lambda_i^G + \mu_i^G = 0, \quad \mu_i^S Q_{it}^S = 0, \quad \mu_i^G Q_{it}^G = 0, \quad (K_i^S - Q_{it}^S)\lambda_i^S = 0, \\ & (K_i^G - Q_{it}^G)\lambda_i^G = 0, \quad K_i^S - Q_{it}^S \ge 0, \quad K_i^G - Q_{it}^G \ge 0, \quad Q_{it}^S \ge 0, \quad Q_{it}^G \ge 0, \\ & \lambda_i^S \ge 0, \quad \lambda_i^G \ge 0, \quad \mu_i^S \ge 0, \quad \mu_i^G \ge 0, \quad i = 1,\dots,N+M, \end{aligned} \tag{13a}$$

and if there is no sun on day *t*, the KKT conditions for firm *i* are as follows:

$$\begin{aligned} & a - 2bQ_{it}^G - b\sum_{k\ne i}^{N+M} Q_{kt}^G + \varepsilon_t - c^G - \lambda_i^G + \mu_i^G = 0, \quad \mu_i^G Q_{it}^G = 0, \quad (K_i^G - Q_{it}^G)\lambda_i^G = 0, \\ & K_i^G - Q_{it}^G \ge 0, \quad Q_{it}^G \ge 0, \quad \lambda_i^G \ge 0, \quad \mu_i^G \ge 0, \quad i = 1,\dots,N+M, \end{aligned} \tag{13b}$$

where λ_i^S and λ_i^G are the dual variables for the capacity constraint of technology **S** and technology **G**, respectively, and μ_i^S and μ_i^G are the dual variables for the non-negativity of Q_{it}^S and Q_{it}^G, respectively.

The Nash equilibrium in outputs is obtained when expressions (13) hold simultaneously for all $N+M$ firms. The solution of (13a) is given in Milstein and Tishler (2012)[22] and the solution of (13b) is given in Tishler et al. (2008).[23]

To determine optimal capacities, the *i*-th firm uses the second-stage reaction functions to solve the following (stage 1) expected profit maximization problem:

$$\max_{K_i^G, K_i^S} \quad \rho E[\sum_{t=1}^{T}(\pi_{it} \mid K_i^S, K_i^G)] + (1-\rho)E[\sum_{t=1}^{T}(\pi_{it} \mid K_i^G)] - \theta^S K_i^S - \theta^G K_i^G, \quad i = 1,\dots,N+M, \tag{14}$$

where expectations are taken over ε_t, $t = 1, \dots, T$.

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[22] See Proposition 3 in Milstein and Tishler (2012).

[23] See Eq. (4) in Tishler et al. (2008).

Assuming that ε_t is uniformly distributed, the equilibrium (symmetric) solution (i.e. $K_1^{S*} = ... = K_{N+M}^{S*} = K^{S*}$ and $K_1^{G*} = ... = K_{N+M}^{G*} = K^{G*}$) is obtained when the following KKT conditions are satisfied:[24]

$$\begin{aligned}
&\rho \cdot \left[[\beta + a - c^S - b(N+M+1)(K^{S*} + K^{G*})]^2 + 2(c^G - c^S)b(N+M+1)K^{G*} \right] - 2(\beta - \alpha)\theta^S / T - \\
&4(\beta - \alpha)b\lambda + 2(\beta - \alpha)\mu^S = 0, \quad \rho\left[\beta + a - c^G - b(N+M+1)(K^{S*} + K^{G*})\right]^2 + \\
&(1-\rho)\left[\beta + a - c^G - b(N+M+1)K^{G*}\right]^2 - 2(\beta - \alpha)\theta^G / T - 4(\beta - \alpha)b\lambda + 2(\beta - \alpha)\mu^G = 0, \\
&\mu^S K^{S*} = 0, \quad \mu^G K^{G*} = 0, \quad \lambda \cdot [\beta + a - c^G - b(N+M+1)(K^{S*} + K^{G*})] = 0, \\
&\beta + a - c^G - b(N+M+1)(K^{S*} + K^{G*}) \geq 0, \quad K^{S*} \geq 0, \quad K^{G*} \geq 0, \quad \lambda \geq 0, \quad \mu^S \geq 0, \quad \mu^G \geq 0,
\end{aligned} \tag{15}$$

where λ is the dual variable for the constraint (stemming from the uniform distribution assumption), and μ^S and μ^G are the dual variables for the non-negativity of K^{S*} and K^{G*}, respectively.

The use of these conditions in numerical analysis is described in the Appendix.

4. The characteristics of the model: Application to real-world data

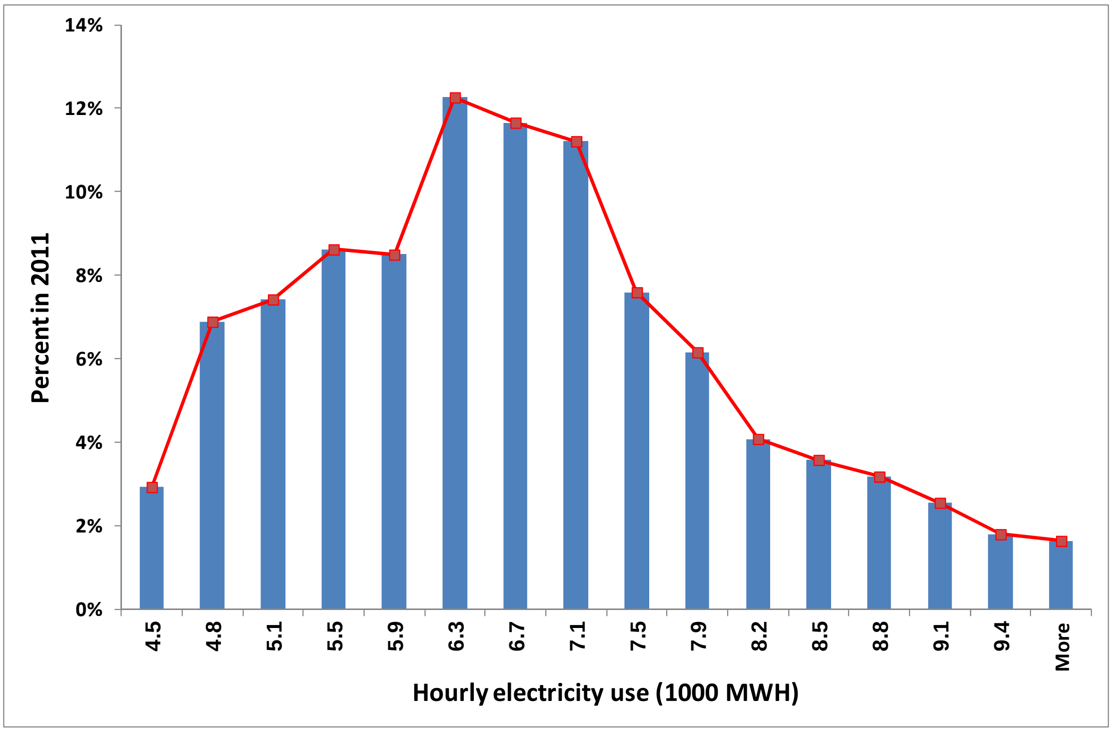
To illustrate its real-world relevance, we apply our model to Israeli data. Table 1 lists descriptive statistics of the hourly electricity use in Israel during 2011 and Figure 1 presents the histogram of these data (IEC, 2012). The data in Figure 1 and Table 1 show that the distribution of the hourly electricity use in 2011 is close to symmetrical, with most of the mass around the mean.

[24] The KKT conditions are built using the proof of Proposition 3 in the Appendix of Milstein and Tishler (2012): the first condition in (15) follows from Eq. (A80a) and the second condition in (15) follows from Eq. (A.80b). The constraint in the maximization problem is derived by using the uniform distribution. That is: $\beta \geq c^G - a + 2bK_i^{S*} + bK_{-i}^{S*} + 2bK_i^{G*} + bK_{-i}^{G*}$.

Table 1: Daily averages and maximal values of electricity use, per hour, in Israel during 2011 (1000 MWH)

	Average hourly use	Maximal hourly use
Mean	6.52	7.89
Median	6.43	7.87
Sample standard deviation	0.88	1.06
Minimum	4.64	5.62
Maximum	8.72	10.4

Figure 1. Histogram of hourly electricity use in 2011



Computation of the optimal capacities is based on estimates of the demand parameters, a and b, the cost parameters, θ^S, θ^G, c^S, c^G, the parameters of the probability function $f(\varepsilon_t)$ and ρ. Using the average generation price in 2011 (66.4 $/MWH) and a (short-run) price elasticity of -0.1 for the daily demand function for electricity, these estimates are as follows (Tishler et al., 2008):[25] $a = 730.4$, $b = 109.2$, $\theta^G/T = 250.0$, $c^S = 0$, $c^G = 40$, $\alpha = -158$ and $\beta = 158$. Our base case assumes that the PV to CCGT capacity cost ratio is 4:1, i.e. $\theta^S/\theta^G = 4$, reflecting the current ratio in the Israeli market (Lior, 2010; Trainer, 2010). We also assume that ρ = 0.48[26] and $N + M = 10$ (for simplicity we set $N = M$ for the market in which firms can construct and operate only one technology; this assumption is eliminated later on).

Figure 2 presents the industry's optimal capacity as a function of θ^S/θ^G (which is constant; i.e. $\theta^G/T = 250.0$). The overall generation capacity increases (or remains unchanged) the lower is the capacity cost of PV (the lower is θ^S/θ^G due to improvements in the PV technology).[27] The distribution of industry capacity between the two technologies is very different across the two market structures. For example, for $\theta^S/\theta^G = 4$, the share of PV capacity (the striped areas of the bars in Figure 2 depict technology **S**) in the industry's total capacity is 35% when each firm can employ only one technology and only 15% when each firm can employ both technologies. Later on we show that most of the industry profits derive from the

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[25] See Khatib (2010) and Lior (2010) and references therein for the costs of electricity generation by various technologies.

[26] This value seems to be realistic for Israel: nights constitute somewhat less than 50% of the year and the sun may appear partially or not at all during 5-10% of the year, mostly during the winter.

[27] When θ^S/θ^G =5, total capacity is lower in the market structure in which firms can employ both technologies, while the opposite holds for lower values of θ^S/θ^G. In seven out of the eight cases presented in Figure 2 the constraint of the first-stage optimization problem is binding, and only when each firm employs both technologies and θ^S/θ^G =5 is it not binding. In fact, PV capacity equals zero when $\theta^S/\theta^G \geq 6$.

CCGT generators, since they are always in operation when prices spike (when the industry is at full capacity), and these spikes are higher when there is no sun and the share of PV capacity is higher. Consequently, generators employing CCGT technology have lower market power when all the firms in the market can employ CCGTs (each firm can use both technologies) and, thus, prefer to build more of the more profitable CCGT generators. The advantage of the CCGT technology over the PV technology is slightly reduced when the capacity cost of PV declines; in this case the increase in the capacity (and capacity share) of the PV technology is somewhat larger in the market structure that allows all firms to construct capacities of both technologies.

Figure 2. Industry capacity

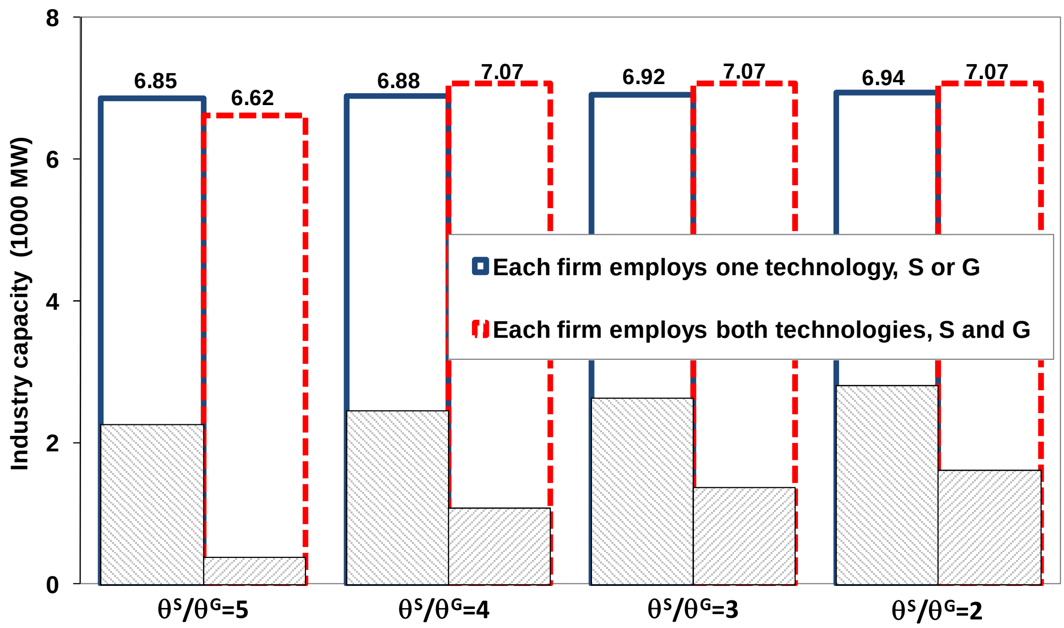
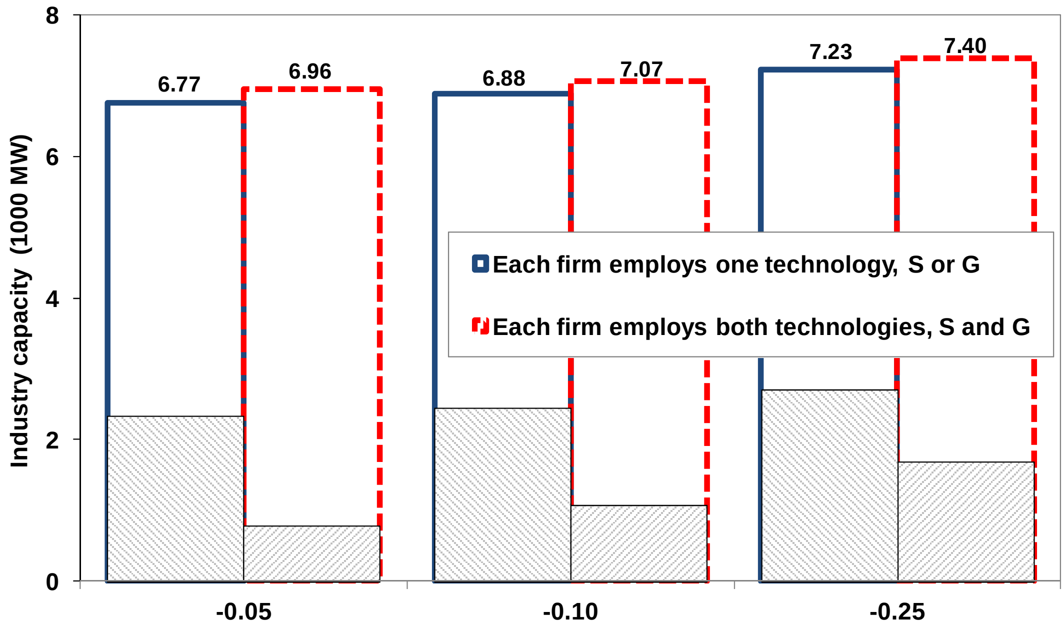


Figure 3 shows the effect of price elasticity on the optimal capacity of each technology, under both market structures, when $\theta^S / \theta^G = 4$. A higher absolute value of price elasticity results in a lower electricity price, which implies higher quantity demanded and, hence, higher generation capacity of both technologies. That is, overall capacity increases and the share of PV capacity (depicted by the striped areas of the bars in Figure 3) in the industry's total capacity increases from 35% to 37% in the market with firms employing only one technology and from 11% to 23% in the market with firms using both technologies when the absolute value of price elasticity rises from -0.05 to -0.25.

Figure 3. Industry capacity as a function of price elasticity ($\theta^S / \theta^G = 4$)



Figures 2 and 3 show that when PV capacity cost decreases, the share of PV capacity in the market in which firms can employ only one technology changes more slowly than in the market in which firms are allowed to employ both technologies. This result holds even when the number of firms employing the PV technology is very large (including the case of many small producers that use only the PV technology). Figure 4 presents the industry's optimal capacity as a function of the number of producers that use the PV technology (the number of firms employing the CCGT technology is unchanged, i.e. $M = 5$). Clearly, overall capacity increases very slightly as the number of PV-using firms in the market increases, and so does the share of PV capacity (depicted by the striped areas of the bars in Figure 4) in the industry's total capacity (from 33% (40%) when $N = 5$ to 36% (45%) when $N = 100$ and $\theta^S/\theta^G = 5$ ($\theta^S/\theta^G = 2$)). That is, the nature of the results of this paper does not change when the number of PV producers is very large, as long as the number of producers that employ CCGT is given.[28]

Figure 4. Industry capacity as a function of *N* (*M* = 5)

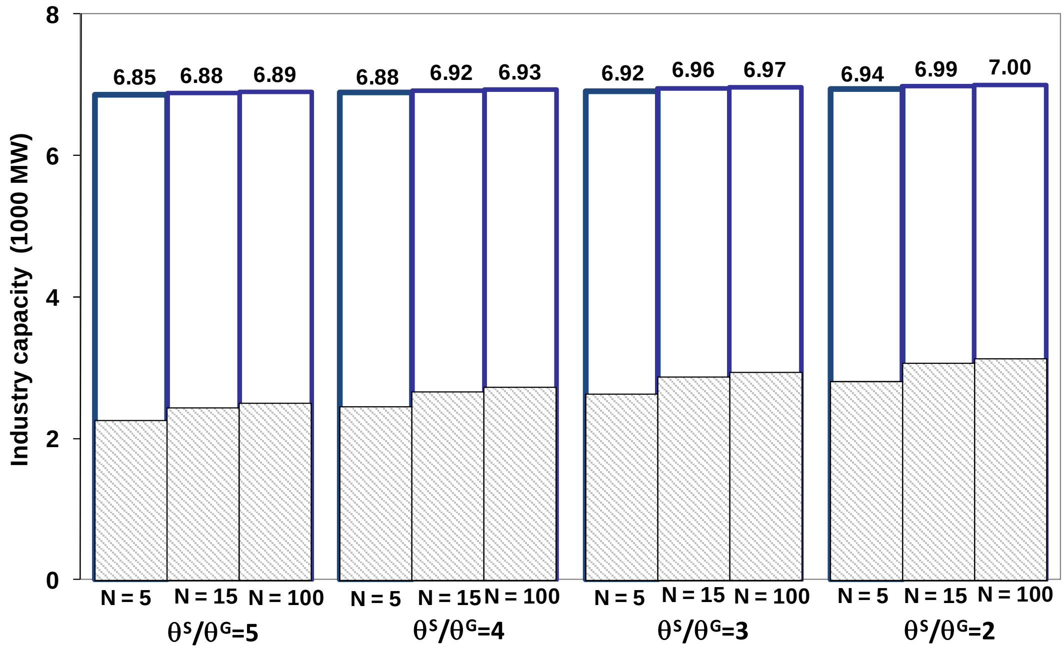


Figure 5 presents the distribution of daily equilibrium electricity prices, for both market structures, during the 365 days of the year. Equilibrium prices are stable when production is below full capacity and rise at an increasing rate once full capacity is reached. The higher is the share of PV capacity in total capacity the sooner is full

[28] This phenomenon mimics a reality in which many small PV producers generate electricity locally.

capacity reached.[29] Thus, price spikes are larger and more frequent the higher the share of PV capacity due to the declining PV capacity cost and/or the lack of market flexibility (i.e. price elasticity that is "low" in absolute value). Consider the case where $\theta^S / \theta^G = 2$. When each firm employs only one technology, full capacity is reached on the 180th day of the year and price spikes higher than 243 $/MHW occur when only CCGT-using firms produce electricity on days without sun; when each firm employs both technologies, firms tend to construct more CCGT capacity, and full capacity is reached on the 236th day of the year.

[29] Price spikes occur when both technologies reach full capacity on a sunny day (the value of the random variable, ε_t, is sufficiently high in this case) or when the CCGT technology reaches full capacity on a day without sun (ε_t may be "low" in this case).

Figure 5. Price distribution

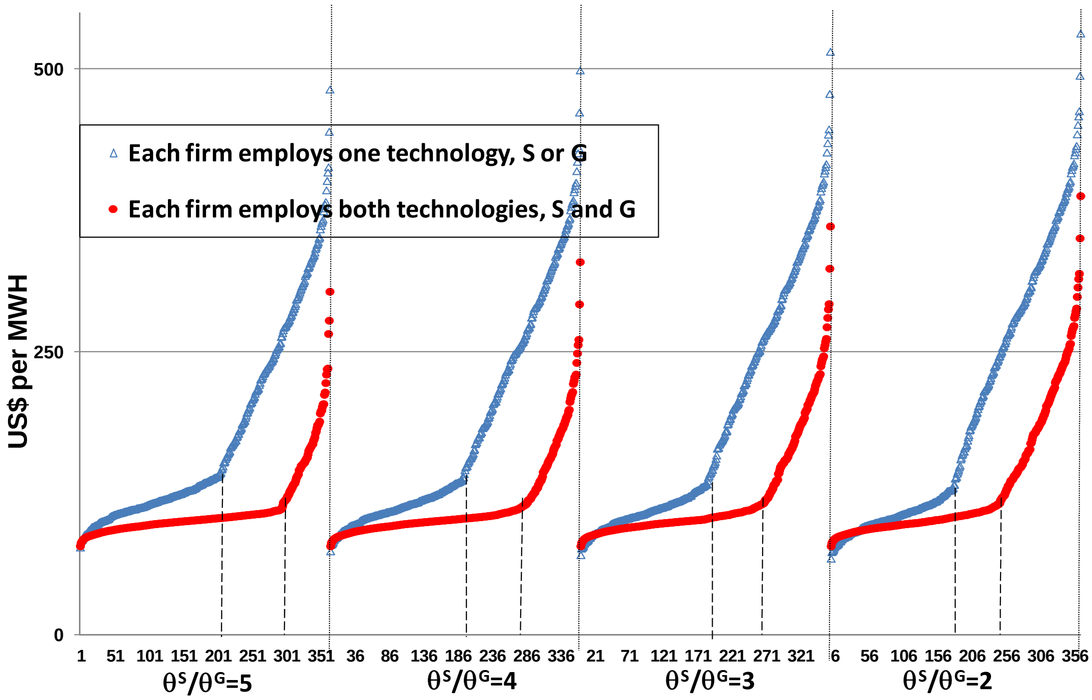


Figure 6 presents the average and maximal electricity prices as functions of θ^S/θ^G, for the two market structures. If the firms can employ only one technology, the average (maximal) price increases from 174 (483) \$/MWH when $\theta^S/\theta^G = 5$ to 183 (532) \$/MWH when $\theta^S/\theta^G = 2$. If each firm can employ both technologies, the average (maximal) price increases from 115 (304) \$/MWH when $\theta^S/\theta^G = 5$ to 132 (389) \$/MWH when $\theta^S/\theta^G = 2$. Figure 7 shows the pattern of electricity prices for several price elasticities. A higher absolute value of price elasticity implies lower electricity prices. However, the phenomenon of electricity prices being higher when each firm can employ only one technology is preserved for all values of price elasticities. Figures 6 and 7 confirm that a larger share of PV capacity yields higher electricity price spikes, since all the demand must be met by the CCGT capacity on days without sunshine. That is, the price spikes on days without sunshine, combined with low price elasticity, is equivalent to giving CCGT producers monopoly power (the ability to raise prices far above marginal cost), particularly when each firm can employ only one generating technology. This phenomenon is more pronounced the greater the number of PV-using firms; when $\theta^S/\theta^G = 5$ ($\theta^S/\theta^G = 2$) the maximal electricity price increases from 483 (532) $/MWH for $N = 5$ to 505 (563) $/MWH for $N = 100$ (see Figure 8). This somewhat unexpected result should give the regulator food for thought.

Figure 6. Average and maximal electricity price

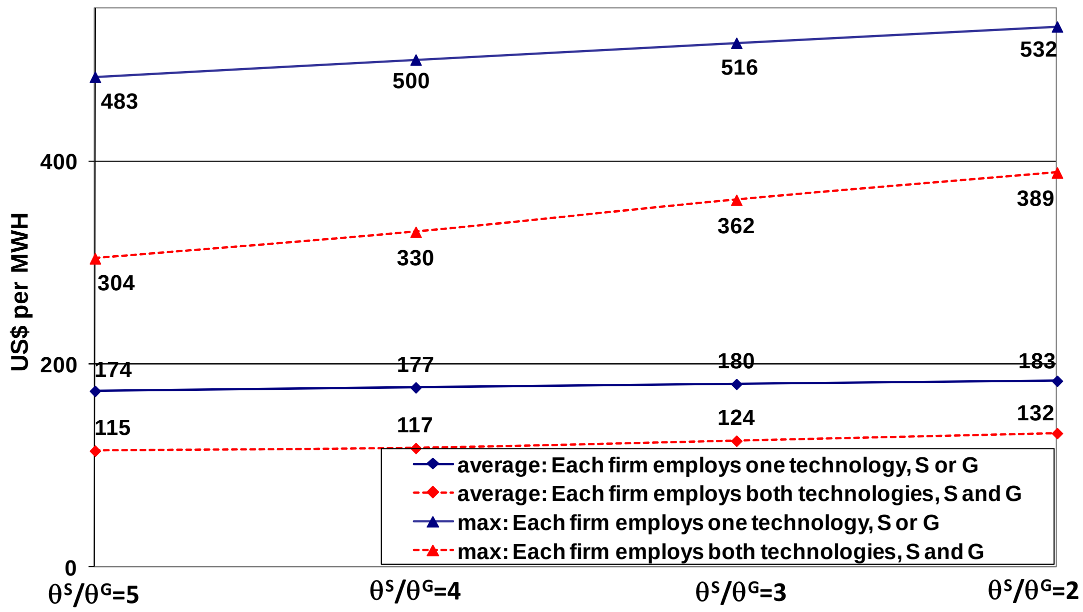


Figure 7. Electricity price as a function of price elasticity ($\theta^S/\theta^G = 4$)

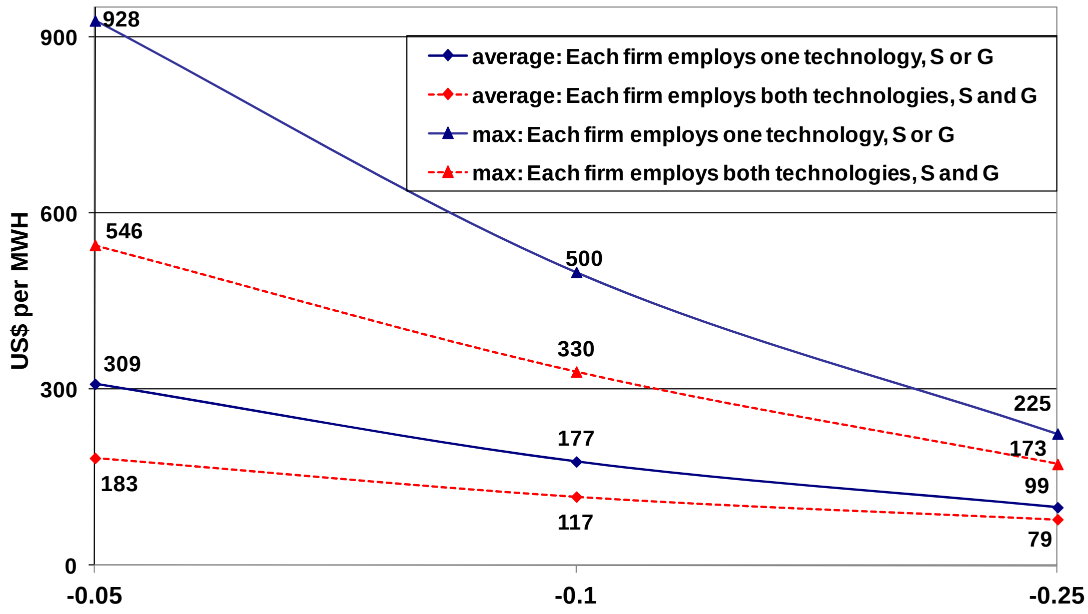


Figure 8. Electricity price as a function of *N* (*M* = 5)

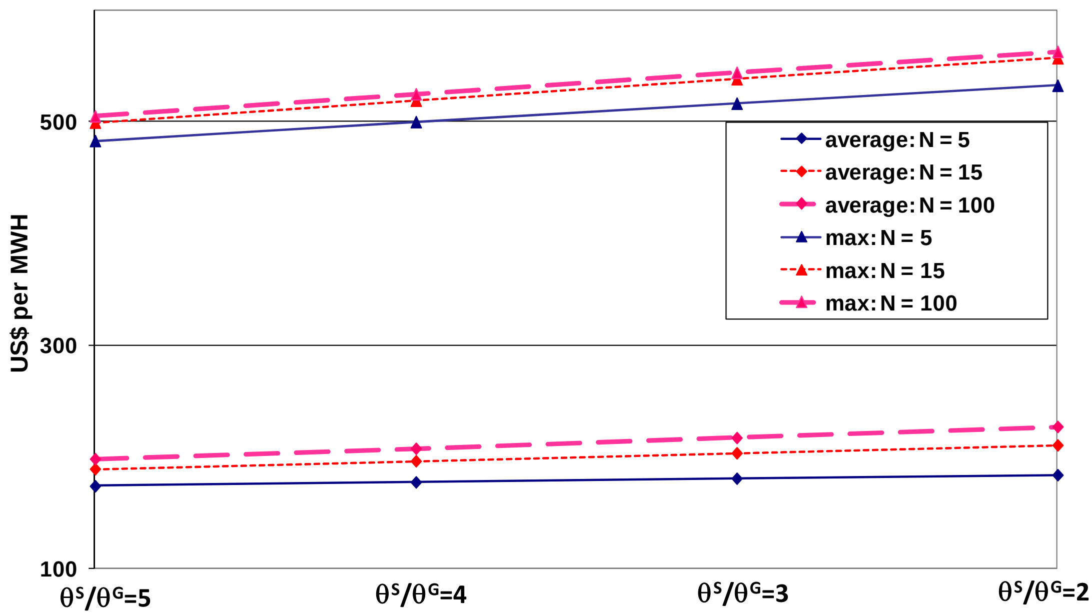


Figure 9 shows that the industry's production is lower when each firm can employ only one technology, and it tends to decline as PV capacity cost declines (due to technology improvements in the construction of PV capacity). This result reflects the increase in the average electricity price when PV adoption rises (the share of PV in total production is depicted by the striped areas of the bars in Figure 9) due to the declining PV capacity cost.[30]

Figure 9. Industry production

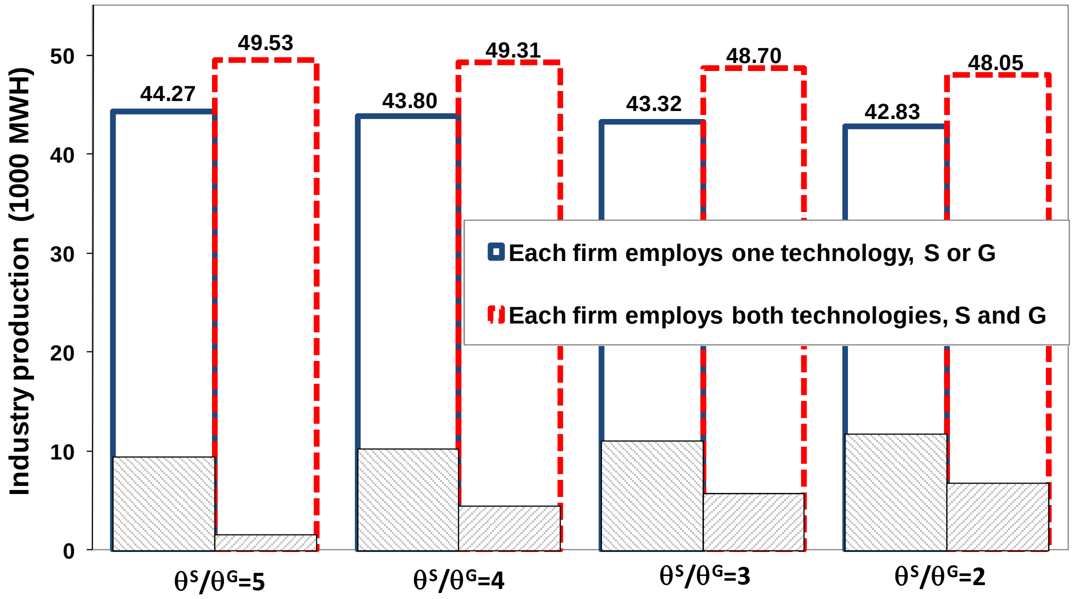


Figure 10 shows that the industry's profit increases when θ^S/θ^G decreases. The increase in profits happens because the cost of electricity production by PV is lower (due to the decline in PV capacity cost) and, mainly, because the revenues from selling electricity are higher due to the higher and more frequent price spikes (and the very low price elasticity which ensures that producers gain more from higher market prices than they lose from declining electricity production, see Figure 9). Clearly, the

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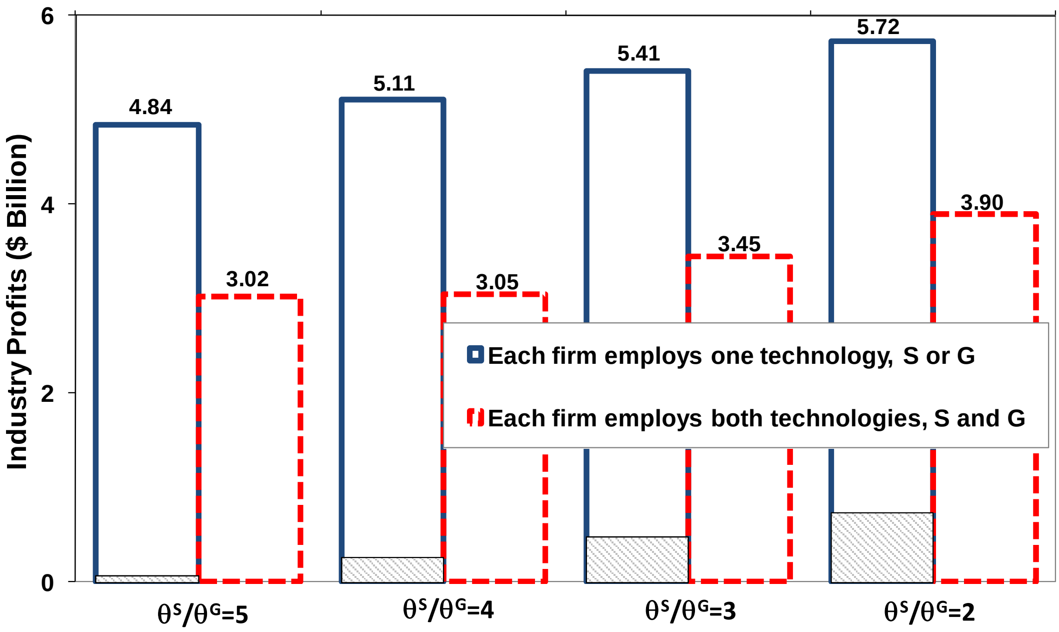
[30] It is straightforward to demonstrate that the industry's electricity production in a competitive market is lower, due to higher average prices, than under the current market regulation (about 53 million MWH in 2009; see IEC, 2012).

PV technology is less profitable in both market structures, despite its declining capacity costs.[31] As expected, industry profits are significantly lower in the market structure in which firms employ both technologies, since the firms, which are allowed to construct and operate both technologies, choose larger CCGT capacity which, in turn, leads to lower prices and lower industry profits. Figure 11 shows the industry's profits as a function of the number of PV-using firms. Industry profits increase as the number of PV-using firms increases from 5 to 100 (since more PV capacity is constructed and price spikes on days without sunshine are higher and more frequent; see Figure 8), although the profit of each PV-using firm declines.

Figure 10. Industry profits



Legend: Profits of the PV-using firms (technology **S**), when each firm employs only one technology, are depicted by the striped areas of the bars.
Profits of the firms that employ CCGTs (technology **G**), when each firm employs only one technology, are depicted by the white areas of the bars.

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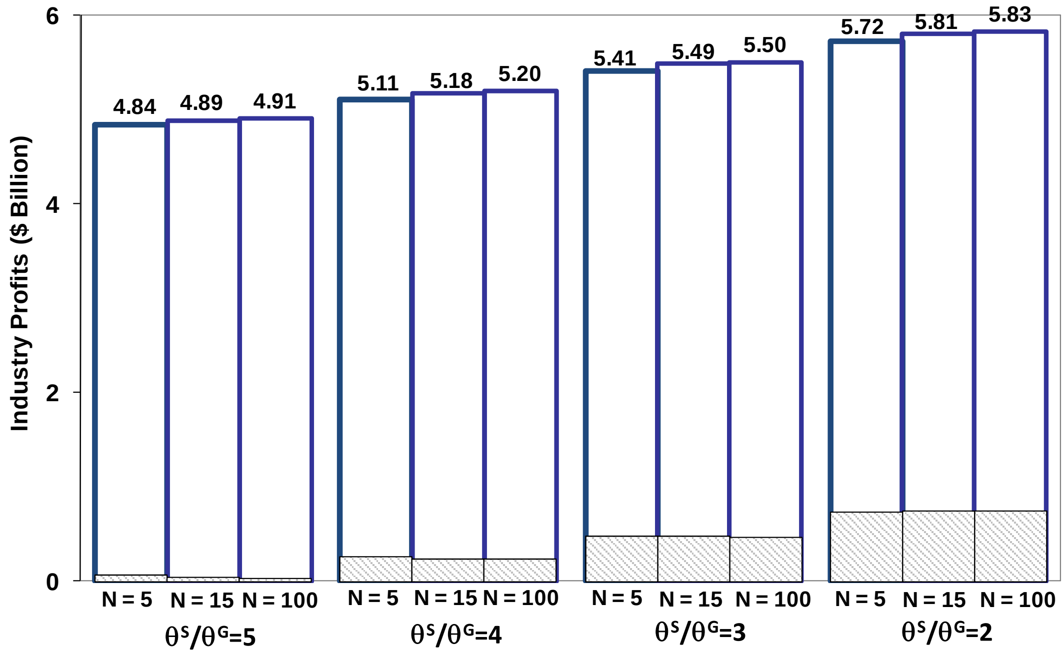
[31] This result is reversed if technology **S** is available at all times; that is, when $\rho = 1$ (see Milstein and Tishler, 2012).

Figure 11. Industry profits as a function of *N* (*M* = 5)



Legend: Profits of the PV-using firms (technology **S**) are depicted by the striped areas of the bars. Profits of the firms that employ CCGTs (technology **G**) are depicted by the white areas of the bars.

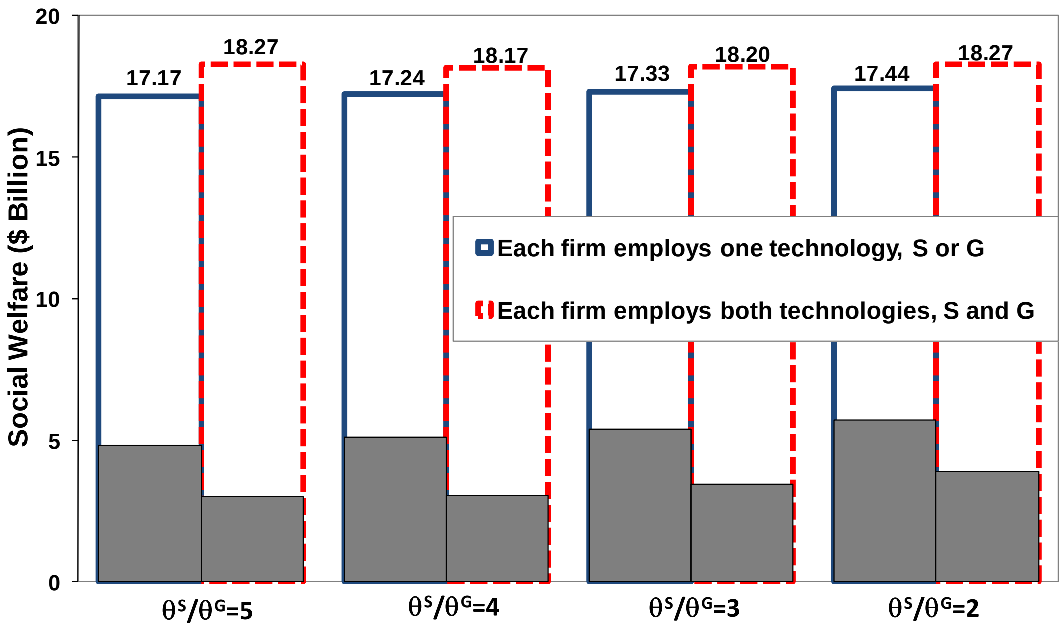
5. Welfare implications of the model: Application to real-world data

Welfare analysis is required to assess the effectiveness of imposing CO_2 taxes and determine which of the two market structures that we compare in Section 4 is preferable. These two issues are the subject of this section. Figure 12 presents the social welfare from electricity generation, for the two market structures that we employ here, as a function of the cost of the PV capacity (consumer surplus is depicted by the white area and profits by the gray area).[32] Though consumer surplus decreases slightly (since the average electricity price increases) when the capacity

[32] The first-best solution in electricity markets may not be attainable (Rogerson, 1990, p. 92) and, therefore, we estimate it as the sum of the industry profits and consumer surplus.

cost of PV declines, social welfare increases.[33] Thus, weaker regulation (letting each firm construct and operate both technologies) leads to higher social welfare. Figure 13 presents social welfare as a function of the number of PV-using firms. Somewhat surprisingly, consumer surplus and social welfare decline, albeit slightly, when the number of firms in a market increases. This phenomenon is caused by the uncertainty about the availability of the PV capacity. A larger number of PV-using firms implies higher PV capacity which, in turn, implies higher and more frequent price spikes and, thus, higher electricity prices (see Figure 8) that reduce consumer surplus more than they increase industry profits.

Figure 12. Social welfare



Legend: Consumer surplus is depicted by the white area of the bars.
Profits are depicted by the gray areas of the bars.

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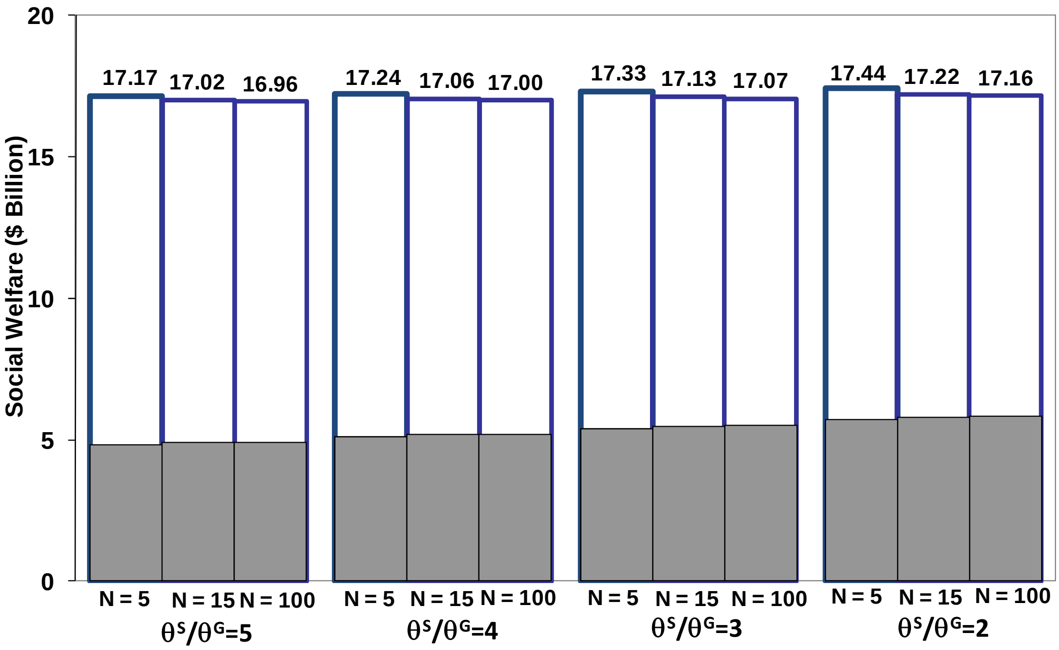
[33] Overall profits increase, but more slowly than consumer surplus decreases, when each firm employs both technologies and the PV to CCGT capacity cost ratio declines from $\theta^S/\theta^G = 5$ to $\theta^S/\theta^G = 4$ (see footnote 26).

Figure 13. Social welfare as a function of *N* (*M* = 5)



Legend: Consumer surplus is depicted by the white area of the bars.
Profits are depicted by the gray areas of the bars.

Next, we assess the effectiveness of taxes on CO_2 emissions. Levying CO_2 taxes is justified by the social cost that is imposed on consumers by CO_2 emissions (Cansino et al., 2010; Borenstein, 2011). CO_2 taxes are controversial and politically difficult to implement even though there is broad agreement that mitigation of GHG is vital. Assessing such taxes within our model will help to determine the level of its effectiveness. That is, it is important to answer the following question: how will CO_2 taxes affect capacity mix, industry profits, consumer surplus and welfare in different market structures? Figures 14-16 show the industry capacity, average and maximal electricity prices and social welfare for three different tax rates: $10, $30 or $50 per ton of CO_2. Obviously, industry capacity decreases, although not by much, the higher the tax on CO_2. In addition, an increase in the tax rate leads to a slight increase in the share of PV capacity (depicted by the striped areas of the bars in Figure 14) in both market structures: setting the tax rate at $50 per ton of CO_2 increases the share of PV capacity from 35% to 40% when each firm employs only one technology, and from 15% to 22% when each firms employs both technologies. Thus, a CO_2 tax is more effective, though not by much, when each firm can construct and employ both technologies. Obviously, the higher the share of PV capacity in the industry's total capacity leads to a higher average (and maximal) electricity price (see Figure 15) when the tax rate increases. Figure 16 shows that increasing the tax rate on CO_2 does little to raise tax payments (depicted by the striped areas in Figure 16), while consumer surplus (depicted by the white area in the figure) and overall welfare decline in response to the increase in the tax on CO_2. Finally, there is very little social benefit (reduction in health problems, for example) from the reduction in CO_2 emissions caused by imposing CO_2 taxes (much less than one percent of social welfare for any tax rate).

Figure 14. Industry capacity when the tax on CO_2 is \$10, \$30 or \$50 per ton

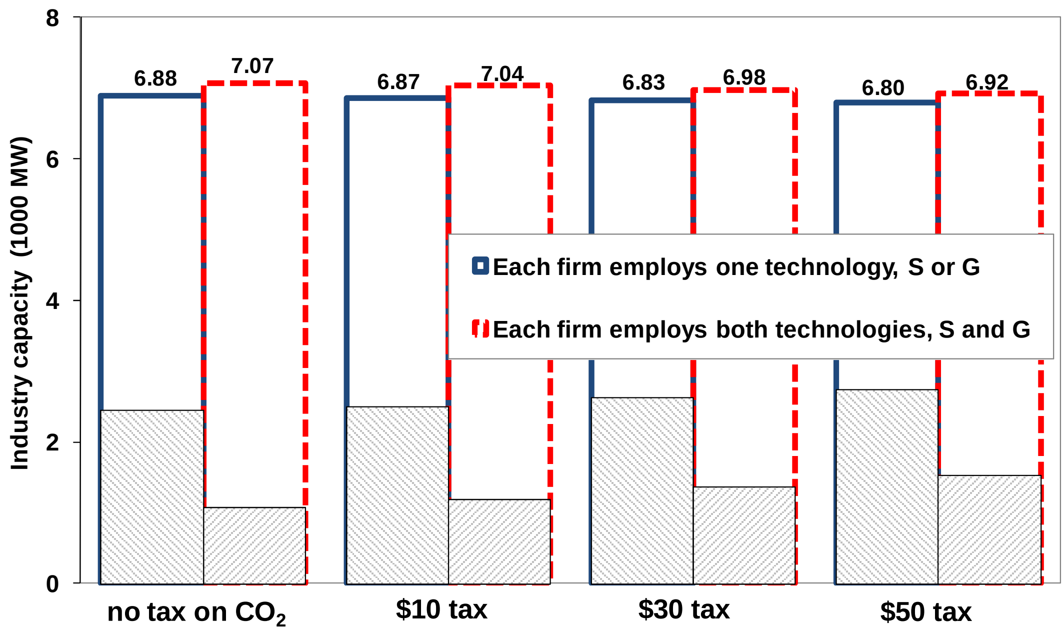


Figure 15. Electricity price when the tax on CO_2 is \$10, \$30 or \$50 per ton

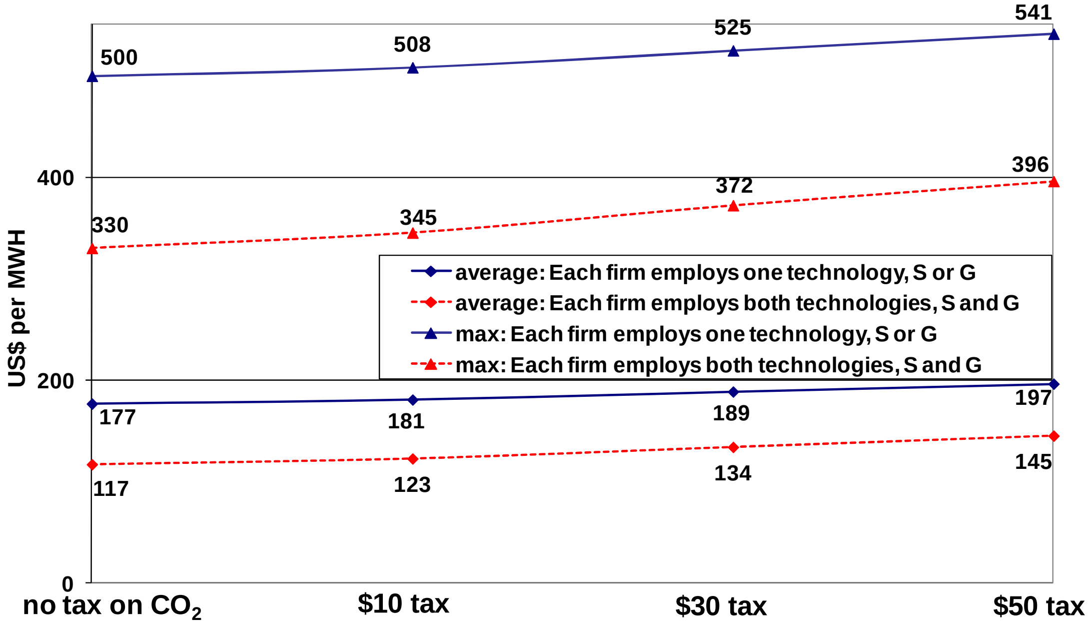
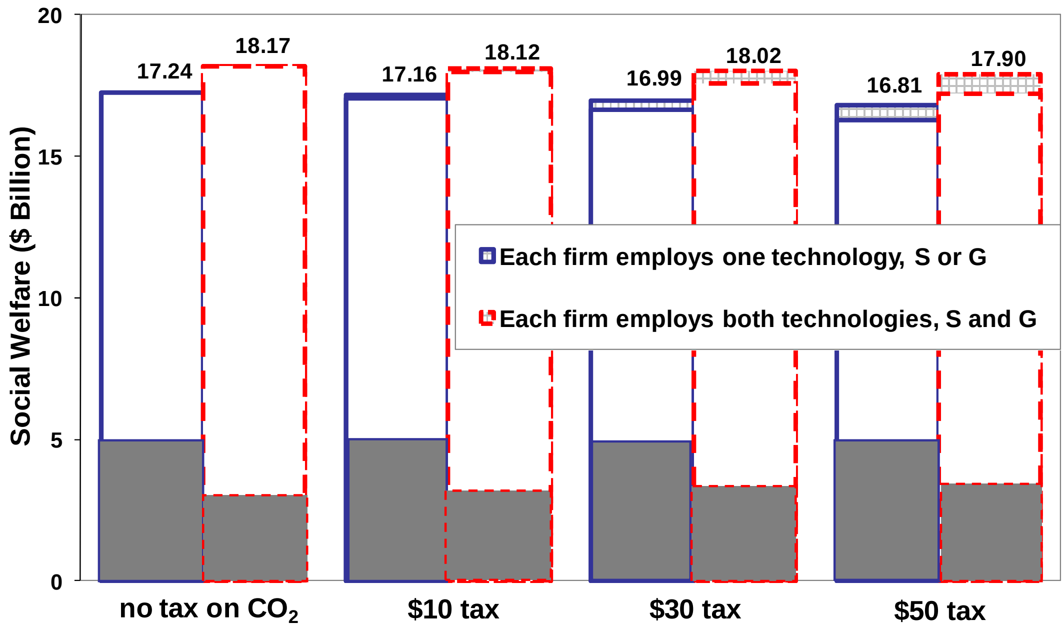


Figure 16. Industry profits, consumer surplus and tax payments when the tax on CO_2 is \$10, \$30 or \$50 per ton



Legend: Industry profits are depicted by the gray area of the bars.
Consumer surplus is depicted by the white area of the bars.
Tax payments are depicted by the striped area of the bars.

6. Conclusion

This paper analyzes the relationships among the optimal endogenous generating capacity mix, electricity production by technology, and market prices and price volatility in a Cournot market with CCGT and PV technologies. We demonstrate that the share of PV capacity in total capacity will be fairly limited in the near future and a CO_2 tax will likely have only a minor effect on PV capacity and production. We also show that the average electricity price is likely to rise when PV adoption rises due to its declining cost as a result of technology improvements, and that market structure may have a large effect on capacity mix and price volatility. Finally, price volatility will rise and welfare may decline should the regulator introduce CO_2 taxes. These results are confirmed by an application to real-world data for the Israeli electricity sector.

The paper highlights that tight generating capacity and frequent electricity price spikes in competitive electricity markets are due not only to demand variability over time (day, season and year), the high cost of constructing capacity and the long lead time required to add new capacity, but also to supply uncertainty, an inevitable outcome in markets with substantial renewable generation capacity (Hardy and Nelson, 2010; Trainer, 2010; Lior, 2010; Milstein and Tishler, 2011).

To be sure, an independent system operator may mitigate price spikes by maintaining capacity reserves that will not be part of the daily market operations (on this issue see Tishler et al., 2008). However, the analysis of this paper underscores the fact that efficient use of renewable capacity requires an integrated approach to the management of electricity markets, one that accounts for modern and properly distributed T&D infrastructure, balancing generation, smart grids, and implementation of appropriate financial and other incentive systems (Lior, 2010; Hardy and Nelson, 2010; Blumsack and Fernandez, 2012, and references therein).

Finally, this paper accentuates the importance of regulators understanding the behavior of the electricity market when considering the promotion of renewable energy or levying a CO_2 tax for the purpose of reducing CO_2 emissions, particularly with respect to the characteristics of renewable technologies, demand and supply uncertainties, and market structure.

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