Current Sustainable/Renewable Energy Reports manuscript No.
(will be inserted by the editor)

Do Renewables Drive Coal-Fired Generation Out of Electricity Markets?

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Received: 26 May, 2021 / Accepted: 14 June, 2021

Abstract
Purpose of Review Coal-fired generation is being retired in many regions. Some argue that these retirements are exacerbated by renewable-generation policy supports. Based on these claims, there are suggestions that renewable supports be phased-out or that coal-fired generators receive their own supports. Given the inherent policy implications, we examine the impacts of renewable-energy supports and other market changes (*e.g.*, low natural-gas prices and carbon policy) on generator profitability.
Recent Findings Renewable-energy policy supports can affect negatively the economics of coal-fired generators. However, empirical analyses in the literature find that the main contributor to declining coal-fired generation is low natural-gas prices. To investigate these findings further, we analyze a case study that is based on Japan's wholesale electricity market. Through this case study, we examine the relative impacts of renewable-energy and other policy and market changes on the economics of coal-fired generation.
Summary Renewable-energy policy can impact the financial viability of coal-fired generators. However, natural-gas-price decreases have a much greater impact on the profitability of coal-fired generators than renewables do at current penetration levels.

Keywords Electricity market · Nash equilibrium · energy policy · wholesale price

1 Introduction

Beginning in 2008, a large number of generators have retired or are in the process of retiring from the United States of America (US) generating fleet. US Energy Information Administration (EIA) provides data on actual and reported planned retirements,[1]

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[1] https://www.eia.gov/electricity/data/eia860m/

which show that coal-fired capacity constitutes a large share of this retirement [1]. Other countries are experiencing similar dynamics with their generation fleets [2]. A question that these retirements raise is their underlying cause. A difficulty in answering this question is that many countries are undergoing a variety of policy and market changes, which may be contributing to these retirements to differing degrees.

Many jurisdictions have explicit policy measures to promote renewable-energy deployment and use [3, 4]. Contemporaneously, the world is experiencing declines in natural-gas prices, due to hydraulic fracturing and liquified-natural-gas exports [5]. Depending upon the relative cost of different generation technologies, these developments can yield price or quantity impacts on the economics of coal-fired generation. With the former, if they are marginal in the wholesale market, renewable or natural-gas-fired generation can impact prices. With the latter, if they are relatively inexpensive, renewable or natural-gas-fired generation can displace coal-fired units.

These market dynamics raise an important policy question. Coal retirements are rational and socially beneficial reactions to market signals if they represent coal's inability to compete with another technology that has better economics [6–8]. Conversely, if coal retirements are an undesirable consequence of policy-driven market distortions, they represent a market failure that may justify a corrective intervention.

This paper contributes to this policy discussion in two ways. First, we survey recent works that examine the drivers of generation-capacity retirements. Much of this literature takes an empirical approach, using historical data to study market dynamics. These works suggest that renewable-energy policy can impact the economics of fossil-fueled generation, but that natural-gas prices have a relatively greater impact. Second, we examine a case study that is based on Japan's wholesale electricity market to conduct a forward-looking analysis of power-system economics. Our case study examines the impacts on wholesale electricity markets of renewable-energy policy, carbon policy, and fuel prices. As the empirical literature suggests, we find that natural-gas prices and carbon policy have greater impacts on power-system economics than renewable-energy policy does.

The remainder of this paper is organized as follows. First, we provide our literature survey, which is followed by a discussion of our case-study methodology, data, implementation, and results. We conclude with a discussion of the policy implications of our work.

2 Pertinent Literature

Many jurisdictions have policy measures enacted to support renewable-energy use or deployment in their electricity sectors [3, 4]. Common policy measures that are used to this end include tariff, quota-obligation, and tendering systems. Tariff systems, *e.g.*, feed-in tariffs, provide direct price-based supports or subsidies to qualifying renewable generators [9, 10]. A quota-obligation system, *e.g.*, a renewable portfolio standard (RPS), specifies a minimum amount of qualifying renewable resources that must be built or used for supplying electricity [9, 11, 12]. Tendering systems are variants of quota-obligation systems, wherein contract(s) to procure renewable energy are executed with developer(s) [13].

The technical literature studies mechanisms by which renewable supports or other environmental policies can impact the economics of fossil-fueled generation. One of the most common impacts is the so-called merit-order effect. The mechanism underlying the merit-order effect is renewable generation displacing higher-cost resources in the dispatch stack. This displacement can impact the economics of a competing generator in two ways. First, the competing generator may be dispatched less, reducing the volume of its production and sales. Second, the marginal generator that sets the market-clearing price (assuming uniform pricing) may be a lower-cost unit. The merit-order effect can be exacerbated by renewable-energy policy, because policy supports can reduce the effective marginal cost of renewable units. Sensfuß *et al*. [14] and Green and Vasilakos [15] analyze the merit-order effect, using Germany's and Great Britain's electricity markets, respectively, as case studies. Both analyses demonstrate the merit-order effect that renewables have on other generating resources and on themselves. The latter effect is pronounced particularly, because the merit-order effect is greatest during times of high renewable production. Thus, the production and price-suppressing effect of renewables are coincident. Sioshansi [16], Schill and Kemfert [17], and Shahmohammadi *et al*. [18] demonstrate the role that energy storage and strategic behavior can play in mitigating the merit-order effect.

Other environmental policies and standards can have a more direct cost-related impact on the economics of electricity generation. Newbery [19] examines the impacts of (what was then) European Community environmental policy on the economics of British coal-fired generation. Fleischman *et al*. [7] conduct a similar analysis for US environmental policy.

These potential impacts raise the question of the extent to which renewable-energy and environmental policy are driving generator retirements and whether these retirements justify interventions of their own. If retirements reflect the inability of coal-fired generation to compete with other generation technologies, they are efficient responses to price signals. Stoft [6] illustrates this market dynamic. He shows that if a power system's capacity mix is optimal (in balancing fixed and variable costs of different technologies), market prices remunerate each generator's cost fully. Otherwise, if the capacity mix is not optimal, relatively expensive generation will not recover cost (driving such resources out of the market) and relatively inexpensive generation will earn positive economic rents (incentivizing additional capacity investment). Conversely, if these retirements are due to undesirable market failures or distortions arising from renewable-energy or environmental policy, further interventions to forestall the retirements may be prudent.

Determining the underlying cause of generation retirement is complicated by other market changes that are occurring concurrently with renewable-energy policy, including historic decreases in natural-gas prices. Houser *et al*. [20] conduct an historical empirical analysis of the US coal market (including non-electricity-production uses). They find that low natural-gas prices are the single largest contributor to recent reduced US coal use. Mills *et al*. [21] focus on US generation retirements. They find no clear correlation between the penetration of renewable energy and the retirement of coal-fired generation. Rather, they find that demand growth, total installed generating capacity, and the intensity of SO_2 emissions from operating a particular coal-fired generator are much more indicative of the retirement of coal-fired generators. Fleischman *et al*. [7] analyze the retirements of coal-fired units from the US generation fleet and identify additional uneconomic units that could be retired and replaced with lower-cost alternatives. Rahmani *et al*. [8] focus their attention on the replacement of coal-fired capacity in PJM Interconnection with wind generators. They show that retiring coal-fired generation can exacerbate transmission-network bottlenecks, which may be mitigated to some extent by the geographic diversity of wind units.

US Department of Energy [22] analyzes generation retirements and comes to a different conclusion that renewable resources have a substantive negative impact on the economics of coal-fired and other dispatchable resources. The report suggests that these retirements may threaten power-system reliability and resilience. The report proposes that policy interventions may be needed, because wholesale markets do not capture the reliability and resilience benefits and value of dispatchable generation with on-site fuel storage. Indeed, the findings of this report are used to propose a rule to Federal Energy Regulatory Commission (FERC) to establish tariffs mechanisms that provide for cost recovery and return on equity for what are termed reliability and resilience resources.[2]

Much of this literature that examines the impacts of renewable-energy and other policies on generator economics and retirements is based on historical empirical analyses. Thus, these works may provide limited insights into potential future changes, *e.g*., decarbonization policy, including possible firm reactions. For instance, generators can adjust their behavior in reaction to policy or other changes [23, 24], which may mitigate or exacerbate impacts *vis-à-vis* historical analyses. Our case study adds to this literature by using empirically validated [25–27] market-equilibrium modeling to examine the impacts of policy and market changes on the profitability of different generation technologies.

3 Case-Study Methodology

We model a market that consists of N profit-maximizing firms that behave *à la* a supply-function equilibrium (SFE) [28]. $\forall i = 1,\ldots,N$, $c_i(q_i)$ denotes firm i's continuously differentiable cost function and the cost functions have the property that $c'_i(0) = c'_j(0), \forall i, j = 1,\ldots,N$. All energy is traded in hourly uniform-price spot markets, each of which has a price cap, $\bar{p}$.

Hourly energy demands are assumed to be price-inelastic, which is consistent with empirical estimates [29], and random. An SFE assumes that each firm commits to a continuously sub-differentiable non-decreasing supply function before knowing demand with certainty. $\forall i = 1,\ldots,N$, we let $q_i(p)$ denote firm i's supply function, which specifies a minimum price, p, at which it is willing to supply up to $q_i(p)$ MW of energy. There is assumed to be a non-zero probability that the demand can be sufficiently high to exhaust the generating capacities of all firms but the largest.

To derive an SFE, $\forall i = 1,\ldots,N$, we express firm i's profit as a function of the spot-market price, p, as:

$$\pi_i(p) = pq_i(p) - c_i(q_i(p))$$

[2] *cf*. FERC docket number RM18-1-000 for details of the proposed rule and FERC's ultimate decision not to make the proposed tariff modifications.

$$= p \cdot \left[D - \sum_{j \neq i} q_j(p) \right] - c_i \left(D - \sum_{j \neq i} q_j(p) \right), \tag{1}$$

where D is the demand. Equation (1) expresses firm i's supply in terms of its residual demand that is unserved by its rivals. Differentiating (1) with respect to p and setting the result equal to zero gives the first-order necessary condition for maximizing firm i's profit:

$$D - \sum_{j \neq i} q_j(p) - p \cdot \left(\sum_{j \neq i} q_j'(p) \right) + c_i'(q_i(p)) \left(\sum_{j \neq i} q_j'(p) \right) = 0,$$

which can be simplified to:

$$q_i(p) - [p - c_i'(q_i)] \sum_{j \neq i} q_j'(p) = 0, \tag{2}$$

which is an ordinary differential equation (ODE) that characterizes firm i's optimal supply function in terms of its rivals' supply functions. An SFE has the property that no firm has a profitable unilateral deviation from an equilibrium set of supply functions [30] and is obtained by solving (2) simultaneously $\forall i = 1, \ldots, N$.

4 Case-Study Data, Implementation, and Calibration

4.1 Case-Study Data

We study Japan's wholesale electricity market using fiscal-year-2017 (FY2017) data. Japan's electricity industry is undergoing restructuring that began during 2005, with additional reforms during 2013 [31]. This market restructuring includes electric utilities separating their generation activities from electricity transmission and distribution. During FY2017, Japan's coal-, natural-gas-, and oil-fired generators (referred to henceforth as fossil-fueled units) were owned and operated by 84 competing firms.

Transmission owners report for their transmission systems historical hourly electricity demands and technology-disaggregated electricity-generation data.[3] We take total hourly electricity demands during FY2017 to be these reported demands. Nuclear, hydroelectric, biomass, co-generation, geothermal, wind, and solar units have limited dispatchability. As such, we fix the hourly output of these non-dispatchable units to the historical generation data that are reported. The net hourly load, which is defined as total demand less the output of the non-dispatchable units, must be served using fossil-fueled generators, which are assumed to behave strategically. The net hourly loads give the values of D in (1).

Herfindahl-Hirschman index (HHI) can be used to estimate the number of firms in a market that can behave strategically and exercise market power [32]. Based on FY2017 HHI of Japan's wholesale electricity market, which is computed using data that are reported by Agency for Natural Resources and Energy (ANRE),[4] we assume

[3] *e.g.*, *cf.* https://www.tepco.co.jp/forecast/html/area_data-j.html for Tokyo-area data.

[4] https://www.enecho.meti.go.jp/statistics/electric_power/ep002/

Table 1 Fossil-fueled generation capacity (GW) that is owned by the eight largest generating firms and competitive fringe

Firm	Coal	Natural Gas	Oil
TEPCO F&P	3.2	29.3	8.7
Chubu	4.1	19.1	2.3
Kansai	1.8	10.2	7.5
Tohoku	3.2	7.4	1.7
Kyushu	2.5	4.6	3.3
J-Power	8.4	0.0	0.0
Chugoku	2.6	2.4	2.8
Hokuriku	2.9	0.0	1.5
Competitive Fringe	18.2	7.9	6.4

Table 2 Non-dispatchable generation capacity (GW) that is owned by the eight largest generating firms and competitive fringe

Firm	Nuclear	Hydroelectric	Pumped Hydroelectric Energy Storage	Wind	PV Solar	Other
TEPCO F&P	0.0	0.0	0.0	0.0	0.0	0.0
Chubu	3.6	2.1	3.3	0.0	0.0	0.0
Kansai	6.6	3.3	4.9	0.0	0.0	0.0
Tohoku	3.3	2.0	0.5	0.0	0.0	0.2
Kyushu	4.7	1.3	2.3	0.0	0.0	0.2
J-Power	0.0	3.6	5.0	0.0	0.0	0.0
Chugoku	0.8	0.8	2.1	0.0	0.0	0.0
Hokuriku	1.7	1.9	0.0	0.0	0.0	0.0
Competitive Fringe	18.4	7.0	9.4	3.0	7.2	11.6

that $N = 8$ and that the eight firms that own the most fossil-fueled capacity are strategic profit-maximizing firms. The remaining firms are assumed to be a competitive fringe. Tables 1 and 2 summarize the technology and ownership breakdown of the generating capacity, all of which is assumed to be available throughout the year.

Fuel costs for fossil-fueled units are estimated from FY2017 fuel-price data[5] and benchmark heat-rate data for different generation technologies.[6] Our model requires that the strategic firms have differentiable cost functions. We obtain affine approximations of each firm's stepped marginal-cost function using linear regression. This is done by discretizing each stepped marginal-cost function in 10-MW increments from zero to the firm's generating capacity and fitting an affine function.

4.2 Equilibrium Computation

There are two challenges to computing an SFE. One is that they are obtained by solving the coupled set of ODEs that is given by (2), which can be difficult [33], es-

[5] https://www.customs.go.jp/toukei/info/index.htm
[6] https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/

pecially to guarantee non-decreasing supply functions. Second, there may be multiple equilibria, which raises the question of which equilibrium to analyze.

With our assumptions, there is a unique SFE with the characteristic that if the demand is sufficiently high to exhaust the generating capacities of all firms but the largest, the equilibrium price is the price cap [34]. Essentially, the largest firm behaves as a residual monopolist and offers its available residual capacity at the price cap when all of its rivals are capacitated. By computing an SFE with this characteristic, and because we assume price-inelastic demand and no forward contracting, the equilibria that we analyze afford the firms the greatest amount of market power [35, 36]. Our goal is to understand how the exercise of market power interacts with policy and market scenarios. Thus, our assumptions provide a bounding case of extremely anti-competitive behavior. We examine also a perfect-competition case to demonstrate market outcomes under the opposite extreme.

To ensure that the supply functions are non-decreasing, we employ the strategy that is suggested by Holmberg [34]. Without loss of generality, we label the firms in descending order of generating capacity (*i.e.*, firm 1 has the greatest generating capacity and firm N the least). Next, we define ΔS_1 as the amount of capacity that firm 1 offers at the price cap and $\forall i = 3,\ldots,N$ we define r_i as the price at which firm i's capacity constraint becomes binding (by definition, $r_2 = \bar{p}$). Thus, we can characterize a potential SFE by the parameter vector, $\theta_N = (\Delta S_1, r_3, r_4, \ldots, r_N)$. We define $\Gamma(\theta_N)$ as the highest price at which one of the supply functions becomes decreasing, *i.e.*, $\exists i \in 1,\ldots,N$ such that $q_i'(\Gamma(\theta_N)) < 0$. For a given θ_N, we can compute $\Gamma(\theta_N)$ by $\forall i = 1,\ldots,N$ integrating (2) from $\bar{p}$ to $c_i'(0)$ and determining the value (if any) at which a supply function becomes decreasing.

In theory, an SFE should have $\Gamma(\theta_N) = c_i'(0)$. In practice, due to numerical errors, one may obtain only a set of supply functions with $\Gamma(\theta_N) > c_i'(0)$ but $\Gamma(\theta_N)$ close to $c_i'(0)$. We compute an SFE by finding θ_N for which $\Gamma(\theta_N)$ is sufficiently close to $c_i'(0)$. We find such a θ_N by solving the optimization problem:

$$\min_{\theta_N} \quad \Gamma(\theta_N) \tag{3}$$

$$\text{s.t.} \quad c_i'(0) \le r_N \le r_{N-1} \cdots \le r_3 \le \bar{p}, \tag{4}$$

using the derivative-free Nelder-Mead optimization algorithm, which is available in `SciPy` 1.0.0 in `Python` 2.7. A derivative-free algorithm is necessary for solving (3)–(4) because the value of $\Gamma(\theta_N)$ can be computed by solving the coupled ODEs (we use the ODE solver in `SciPy` 1.0.0 for this purpose) for a given value of θ_N, whereas its derivatives cannot be computed easily.

There are two difficulties in solving (3)–(4). One is that (3) is non-convex, which means that Nelder-Mead algorithm may terminate at a local minimum. A second complication is that with many firms, (3)–(4) and the coupled ODEs may be intractable. We use Algorithm 1 to address these two complications. The algorithm works by computing first an SFE using the three largest firms only, after which new SFE are computed iteratively by adding firms one by one.

Line 1 initializes the algorithm by finding an initial value value for θ_3, which we denote as θ_3^0 and a 2-orthotope-shaped trust region, which is defined by the bounds, $\theta_3^{\min}$ and $\theta_3^{\max}$. The values of θ_3^0, $\theta_3^{\min}$, and $\theta_3^{\max}$ are obtained from visual inspection

Algorithm 1 Model (3)–(4) Solution

1: **initialize:** $\theta_3^0 \leftarrow \tilde{\theta}_3$, $\theta_3^{\min} \leftarrow \tilde{\theta}_3^{\min}$, $\theta_3^{\max} \leftarrow \tilde{\theta}_3^{\max}$
2: **for** $i \leftarrow 3$ to N **do**
3: $\quad\theta_i^* \leftarrow \arg\min_{\theta_i^{\min} \le \theta_i \le \theta_i^{\max}} \Gamma(\theta_i)$, using θ_i^0 to warm-start
4: $\quad r_{i+1}^0 \leftarrow \tilde{p}_{i+1}$, $r_{i+1}^{\min} \leftarrow \tilde{p}_{i+1}^{\min}$, $r_{i+1}^{\max} \leftarrow \tilde{p}_{i+1}^{\max}$
5: $\quad\theta_{i+1}^0 \leftarrow (\theta_i^*, r_{i+1}^0)$, $\theta_{i+1}^{\min} \leftarrow (\theta_i^{\min}, r_{i+1}^{\min})$, $\theta_{i+1}^{\max} \leftarrow (\theta_i^{\max}, r_{i+1}^{\max})$
6: **end for**

of a contour plot, which is detailed in discussing Line 4 of the algorithm. Lines 2–6 constitute the main iterative loop. For each i, Line 3 minimizes $\Gamma(\theta_i)$ subject to the bound constraints using θ_i^0 as an initial point to obtain an i-firm SFE. A contour plot of $\Gamma(\theta_{i+1})$ as a function of r_i and r_{i+1} is inspected visually in Line 4 to determine an initial value for r_{i+1}, which we denote as r_{i+1}^0, and bounds on r_{i+1}, which we denote as $r_{i+1}^{\min}$ and $r_{i+1}^{\max}$. Figure 1 shows an example contour plot for a case in which $i = 4$, meaning that a starting value and bounds for r_5 are being found through visual inspection. The starting value, θ_{i+1}^0, and bounds, $\theta_{i+1}^{\min}$ and $\theta_{i+1}^{\max}$, for θ_{i+1} are updated in Line 5. Visual inspection of Fig. 1 shows that the three regions that are surrounded by red boxes contain undesirable local minima (the resultant supply functions would yield highly competitive behavior by the generating firms). The region that is surrounded by a black box contains the desired global minimum. As such, r_5 is restricted to be between $r_5^{\min} = 29$ and $r_5^{\max} = 44$ in the example that is shown in Fig. 1.

Once an SFE is computed using Algorithm 1, hourly prices are determined by intersecting hourly net demand with the equilibrium aggregate supply function. The aggregate supply function is the sum of the supply function of the competitive fringe, which equals marginal generation cost, and of the equilibrium supply functions for the eight strategic firms. A technical complication arises from the fact that, due to numerical errors, we have $\Gamma(\theta_N) > c_i'(0)$. We address this by applying linear interpolation to the logarithm of the equilibrium supply functions between $\log(c_i'(0))$ and $\log(\Gamma(\theta_N)), \forall i = 1, \ldots, N$. Each firm's hourly output is determined from the corresponding spot-market price by inverting its equilibrium supply function.

4.3 Case-Study Calibration

Currently, the Japanese wholesale electricity spot market allows generators to submit supply offers at any price up to 1000 JPY/kWh. Figures 2 and 3 provide scatterplots of hourly computed equilibrium and historical FY2017 prices against total hourly electricity demand. Figure 2 assumes the actual market price cap of 1000 JPY/kWh in computing an SFE whereas Fig. 3 assumes a lower price cap of 100 JPY/kWh. Figure 2 shows that historical prices are lower than the computed SFE suggests. This result may stem from Japan's wholesale electricity market being in relative infancy. Empirical analyses of the California and Texas electricity markets suggest that firms can be conservative in exercising market power when a market is relatively immature but that their exercise of market power increases as the market develops [23, 25, 37].

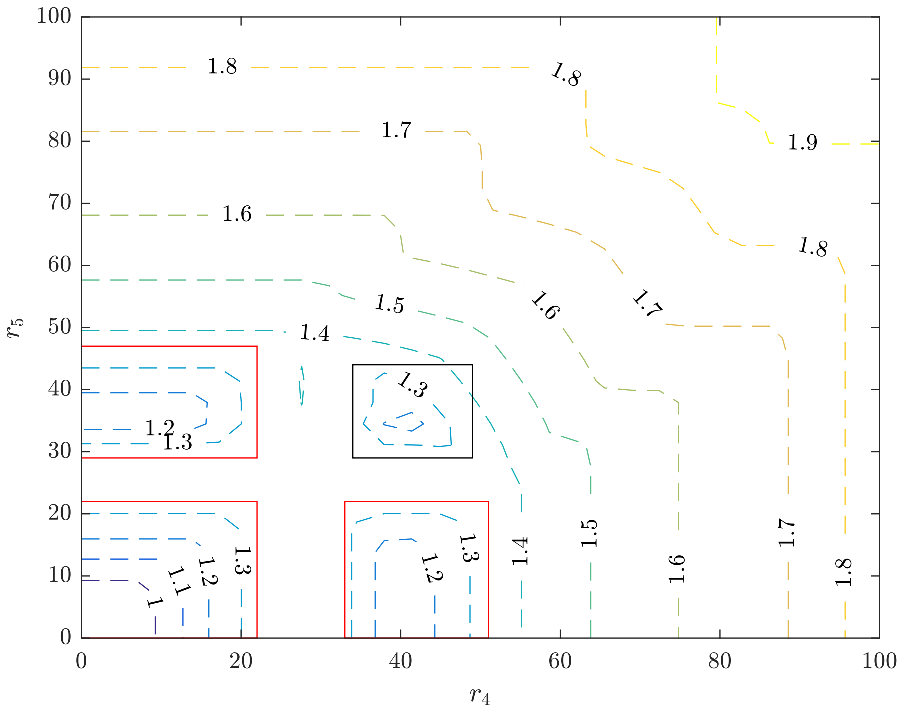

Fig. 1 Contour plot of $\log(\Gamma(\theta_5))$ as a function of r_4 and r_5

Given these findings, we consider two market-maturity scenarios. The first, assumes a 100-JPY/kWh price cap and yields equilibrium prices that are closer to the historical FY2017 prices. This case corresponds to relatively immature market conditions and allows exploring how policy and market conditions would impact firm behavior, market prices, and profits under current market-power conditions. The second scenario assumes a 1000-JPY/kWh price cap and reflects the impacts of policy and market conditions under potential future market-power conditions.

4.4 Market and Policy Scenarios

We consider six policy and market scenarios. One is a business-as-usual case, which is calibrated to FY2017 data. Two scenarios achieve, respectively, actual year-2030 and -2050 renewable-energy targets and are modeled by scaling hourly FY2017 wind and PV-solar production. The 2030-renewable case has seven and two times as much wind and PV solar, respectively, as is deployed in 2017. These targets increase to 14 and four times, respectively, for the 2050-renewable case. The next scenario has natural-gas prices that are one-third lower than FY2017 values. The final two scenarios have carbon taxes, which are levied on fossil-fuel consumption. The first case

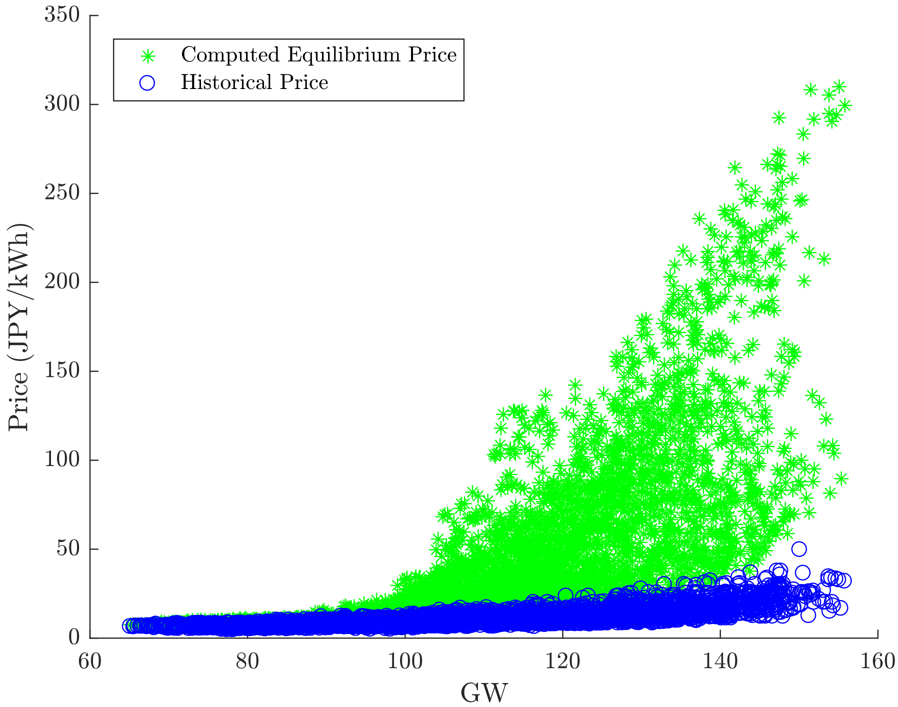

Fig. 2 Scatterplots of hourly computed equilibrium (assuming a 1000-JPY/kWh price cap) and historical FY2017 prices against hourly total electricity demand

uses a central-estimate carbon tax of 5169.72 JPY/t-CO_2 and the second uses a high-impact carbon tax of 15105.26 JPY/t-CO_2 [38].[7]

4.5 Profit Analysis

We assess generator profitability by the maximum capital charge rate (CCR) that market revenues can sustain, which is a back-of-the-envelope measure of whether an investment can be sustained by market revenues [39]. The maximum CCR is computed as the ratio between annual operating profits that a generator earns (*i.e.*, revenues from energy sales less operating costs) and its overnight capital costs. Generator capital and fixed operation and maintenance costs are estimated from ANRE data.[8]

[7] The social-cost-of-carbon estimates are reported in 2007 USD/t-CO_2. We use United States Consumer Price Index data and the simple-average FY2017 exchange rate to convert the estimates to 2007 JPY/t-CO_2.

[8] https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/

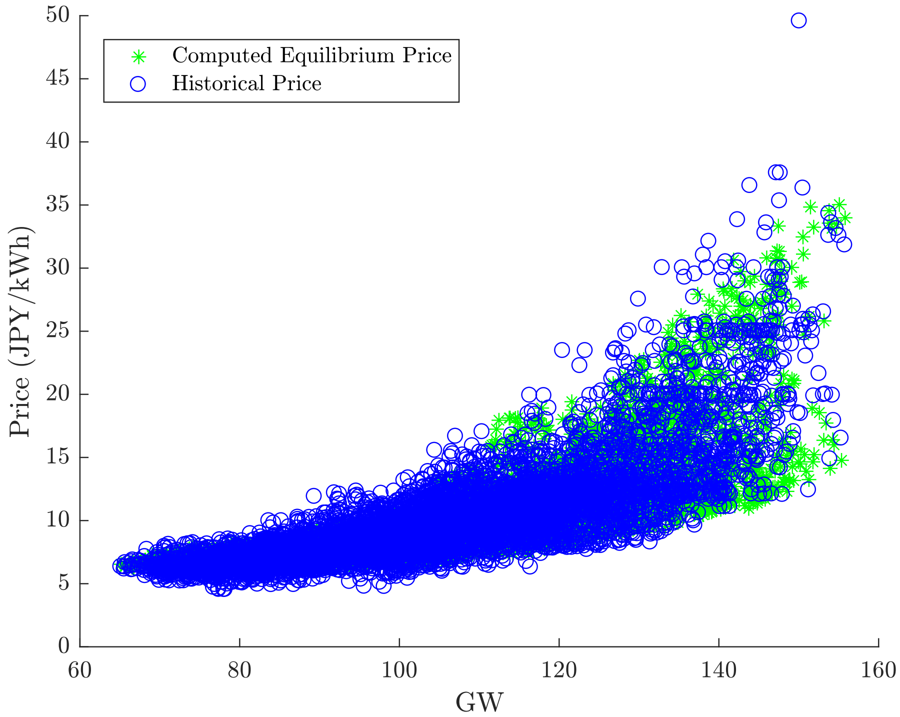

Fig. 3 Scatterplots of hourly computed equilibrium (assuming a 100-JPY/kWh price cap) and historical FY2017 prices against hourly total electricity demand

5 Case-Study Results

5.1 Energy Mix

Table 3 summarizes the generation mix that is used to satisfy electricity demands with a 100-JPY/kWh price cap. The business-as-usual, low-natural-gas-price, and carbon-tax scenarios have relatively low renewable-energy supply (1% and 7% for wind and PV-solar units, respectively). The high-renewable scenarios have greater renewable-energy supply (7% and 15% with the 2030 target and 13% and 27% with the 2050 target for wind and PV-solar units, respectively).

Contrasting the business-as-usual, low-natural-gas-price, and carbon-tax scenarios shows that natural-gas-fired generation takes on a disproportionate amount of the generation mix in the latter two. Coal-fired generation supplies 56% of energy under the business-as-usual scenario whereas this drops to 35% and 33% with the central-estimate and high-impact carbon-tax rates, respectively, and 34% with low natural-gas prices.

Table 3 Technology mix (TWh) of electricity that is produced under policy and market scenarios assuming a 100-JPY/kWh price cap

	Coal	Natural Gas	Oil	Wind	PV Solar
Business as Usual	390.7	219.6	21.8	6.5	51.0
High Renewable					
2030	364.4	165.3	12.3	45.7	102.1
2050	295.9	112.3	7.1	89.3	185.2
Low Natural-Gas Price	231.3	385.8	15.0	6.5	51.0
Carbon Tax					
Central Estimate	242.6	370.4	19.2	6.5	51.0
High Impact	230.1	381.4	20.6	6.5	51.0

Table 4 Maximum CCR (%) for different technologies that market revenues can sustain under policy and market scenarios assuming a 100-JPY/kWh price cap

	Coal	Natural Gas	Oil	Wind	PV Solar
Business as Usual	12.2	6.1	−2.5	4.4	2.3
High Renewable					
2030	7.3	1.6	−3.1	3.2	1.5
2050	3.6	−0.6	−3.2	2.1	0.1
Low Natural-Gas Price	3.4	20.6	−2.8	3.3	1.6
Carbon Tax					
Central Estimate	4.8	15.0	−2.6	6.4	3.6
High Impact	1.8	27.5	−2.8	10.5	6.2

5.2 Profit Analysis

Table 4 summarizes the maximum CCR that the revenues that each generation technology earns can sustain under the six policy and market scenarios, with a 100-JPY/kWh price cap. All of the generation technologies, with the exception of oil-fired units, can sustain positive CCRs with market revenues. This means that these technologies earn positive net operating profits from the provision of energy. An 11% CCR is considered reasonable for electricity-industry investments [39, 40]. The maximum CCRs that are reported for oil-fired generators are negative, meaning that these units operate at a net loss. Negative operating profits stem from small inframarginal rents that such units earn and fixed operation and maintenance costs, which are greater than the profits that they earn from supplying energy.

Table 4 shows that coal-fired generators are estimated to be able to sustain up to a 12% CCR in the business-as-usual scenario. This decreases by over 70% in the low-natural-gas-price scenario. Conversely, low natural-gas prices increase the maximum CCR that can be sustained by natural-gas-fired plants by over 230% relative to business as usual. The carbon-tax scenarios show profit outcomes for fossil-fueled generators that are similar to the low-natural-gas-price scenario.

Table 4 shows also that renewables have relatively muted impacts, relative to low natural-gas prices or a carbon tax, on the profitability of coal-fired generators. These results suggest that policy measures to encourage the adoption of renewables have

Table 5 Technology mix (TWh) of electricity that is produced under policy and market scenarios assuming a 1000-JPY/kWh price cap

	Coal	Natural Gas	Oil	Wind	PV Solar
Business as Usual	386.9	193.7	51.5	6.5	51.0
High Renewable					
2030	359.8	147.3	34.9	45.7	102.1
2050	291.2	102.2	21.8	89.3	185.2
Low Natural-Gas Price	249.9	341.2	40.9	6.5	51.0
Carbon Tax					
Central Estimate	259.5	313.9	58.7	6.5	51.0
High Impact	240.5	337.7	53.8	6.5	51.0

Table 6 Maximum CCR (%) for different technologies that market revenues can sustain under policy and market scenarios assuming a 1000-JPY/kWh price cap

	Coal	Natural Gas	Oil	Wind	PV Solar
Business as Usual	73.2	62.2	21.4	19.3	7.4
High Renewable					
2030	34.1	23.0	5.3	9.0	2.4
2050	16.3	8.3	−0.1	4.5	0.3
Low Natural-Gas Price	48.6	93.3	19.7	18.1	6.6
Carbon Tax					
Central Estimate	52.9	89.6	21.8	21.8	9.0
High Impact	46.1	100.2	20.3	25.3	11.3

relatively small impacts on the profitability of fossil-fueled generation, unless these measures achieve very high renewable-energy penetrations.

5.3 Market Maturity

Tables 5 and 6 summarize the same results that Tables 3 and 4 do, but Tables 5 and 6 assume a 1000-JPY/kWh price cap. Table 5 shows that with a 1000-JPY/kWh price cap there is a systematic decrease in electricity production from natural-gas-fired generators. This decrease is because natural-gas-fired-generating capacity is owned predominantly by the larger generating firms, which have greater propensity to exercise market power relative to other firms. An impact of the larger generating firms exercising market power is that their natural-gas-fired generators are withheld from the market, which results in more energy being supplied by coal- and oil-fired units.

Table 7 summarizes the generation mix that is used to satisfy electricity demands, assuming perfectly competitive behavior by all firms. Tables 3, 5, and 7 show that the exercise of market power has two important impacts on the mix of generation fuels that is used to supply energy. Under business as usual, coal-fired generation displaces oil-fired units and constitutes a larger portion of the energy mix under perfect competition *vis-à-vis* the exercise of market power. Thus, market power can yield a cleaner generation mix by allowing some substitution of generation fuels. However, this result is sensitive to the portfolio of generating units that are owned by individual firms.

Table 7 Technology mix (TWh) of electricity that is produced under policy and market scenarios assuming perfect competition

	Coal	Natural Gas	Oil	Wind	PV Solar
Business as Usual	409.7	222.4	0.0	6.5	51.0
High Renewable					
2030	390.7	151.3	0.0	45.7	102.1
2050	321.5	93.6	0.0	89.3	185.2
Low Natural-Gas Price	25.6	606.5	0.0	6.5	51.0
Carbon Tax					
Central Estimate	25.6	606.5	0.0	6.5	51.0
High Impact	25.6	606.5	0.0	6.5	51.0

Tables 3, 5, and 7 show that the policy and market scenarios that we consider have markedly different impacts on reducing the electricity sector's carbon footprint. Low natural gas prices and carbon taxes eliminate almost all use of coal-fired generation under perfect competition. This is because under perfect competition, the generation fleet is operated based solely on cost and natural gas is less costly than coal. Carbon taxes and low natural gas prices result in 384 TWh of coal-fired generation being replaced by another generation fuel under perfect competition. With the exercise of market power, these reductions range between 127 TWh and 161 TWh.

Conversely, renewables-related policy has the opposite relative impact on reducing the carbon intensity of the generation mix that is used. Under perfect competition the 2030- and 2050-high-renewable scenarios yield 19-TWh and 88-TWh reductions, respectively, in coal-fired generation. This can be contrasted with reductions in coal-fired generation of between 26 TWh and 27 TWh and between 95 TWh and 96 TWh under the 2030- and 2050-high-renewable scenarios, respectively, with the exercise of market power. Renewables policy has a relatively muted carbon-reduction impact under perfect competition because it does not impact the cost of coal-fired generation relative to other generation fuels. Thus, coal-fired generation is prioritized over natural-gas- and oil-fired units. With the exercise of market power, some coal-fired generation is withheld from the market, resulting in other fuels being used in place of more-carbon-intense coal-fired generation.

6 Discussion and Conclusions

The business-as-usual and 2030-high-renewable scenarios yield greater profits to coal-fired generators than the low-natural-gas-price scenario does. These results suggest that concerns surrounding the impacts of renewables-related policy on the profitability of other generating technologies are misplaced. Rather, financial pressure on coal-fired generation is more likely to stem from current historically low natural-gas prices. This finding is consistent with other empirical analyses of coal economics [20, 21].

Thus, recent or forthcoming retirements of coal-fired units from the generation fleet should be viewed as reactions to market signals that another technology (predominantly natural-gas-fired generation) has a competitive advantage. As such, policy interventions to forestall the retirement of coal-fired units should be viewed skeptically, as they countermand socially beneficial market-driven adjustments to the generation fleet [6, 7]. This is in addition to the societal benefits of reductions in the carbon footprint of the electricity system, which is an ancillary spillover effect of the relative economics of generation fuels [8].

Our results should not be interpreted as renewables-related policy having *no* impacts on the profitability of other generation technologies. The 2050-high-renewables scenario yields profit decreases to almost all generation technologies relative to the low-natural-gas-price scenario. This finding means that if it is sufficiently aggressive, renewables-related policy can distort market signals, which is consistent with other analyses [41]. However, the necessary renewable-penetration levels are significantly higher than those that are seen in most regions today. Indeed, EIA data show that during 2018, the penetration of wind and solar units (on an energy basis) in California and across US were on the same scale as the 2030-high-renewable and business-as-usual scenarios.

Our case study reveals sensitivity of market and environmental outcomes to the exercise of market power, which may not be revealed in empirical analyses. Other studies that employ market-equilibrium models [42] reveal the impact of market power on environmental outcomes. For instance, addressing one market failure by pricing the externality of carbon emissions can yield worse environmental outcomes. Such counter-intuitive outcomes can occur because an un-addressed market failure (*e.g.*, the exercise of market power) is exacerbated by the corrective action. Nuanced findings such as these reinforce the value of undertaking market-equilibrium analysis to understand how to structure energy and environmental policy. Nevertheless, our specific findings regarding market and environmental outcomes are highly sensitive to the data and portfolio mix that underlie our case study.

We neglect market risk in our analysis. The maximum sustainable CCRs that are reported in Tables 4 and 6 give a sense of the 'average' profitability of different generating technologies over the course of an illustrative year. Our analysis does not account for the relative riskiness of technology investment, though. For instance, the 2050-high-renewable scenario with a 1000-JPY/kWh price cap results in the energy price being 0 JPY/kWh during 930 hours (about 10.6%) of the year. The same scenario yields energy prices that are above 50 JPY/kWh during 175 hours (about 2.0%) of the year. This means that generation technologies must rely on producing energy during a very small portion of the year to recover costs. This is a risky proposition, because small changes to market conditions, which must be forecasted or predicted when making an investment decision, can yield vastly different prices and market conditions.

Acknowledgements This work was supported by National Science Foundation Grant 1808169. The authors thank Antonio J. Conejo (The Ohio State University), Makoto Tanaka (National Graduate Institute for Policy Studies), Andy Philpott (The University of Auckland), and Armin Sorooshian (University of Arizona) for helpful comments and discussions. The first author thanks Tokushu Tokai Paper Co., Ltd. for its financial support of his Ph.D. studies at The Ohio State University. Any opinions and conclusions that are expressed in this paper are solely those of the authors.

Compliance with Ethical Standards

Conflict of Interest The authors declare no competing interests.

Human and Animal Rights and Informed Consent This article does not contain any studies with human or animal subjects performed by any of the authors.

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