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ORIGINAL ARTICLE

The impact of carbon cap and trade regulation on congested electricity market equilibrium

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Abstract Greenhouse gas regulation aimed at limiting the carbon emissions from the electric power industry will affect system operations and market outcomes. The impact and the efficacy of the regulatory policy depend on interactions of demand elasticity, transmission network, market structure, and strategic behavior of generators. This paper develops an equilibrium model of an oligopoly electricity market in conjunction with a cap-and-trade policy to study such interactions. We study their potential impacts on market and environmental outcomes which are demonstrated through a small network test case and a reduced WECC 225-bus model with a detailed representation of the California market. The results show that market structure and congestion can have a significant impact on the market performance and the environmental outcomes of the regulation while the interactions of such factors can lead to unintended consequences.

Keywords Power market modeling · Electric power markets · Cap-and-trade programs · Carbon dioxide emissions · Market power

JEL Classification Q53 · Q58 · L13 · L94

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1 Introduction

In 2009, the electric power sector accounted for 40% of US energy consumption, of which 70% was supplied by fossil fuels such as natural gas, coal, and petroleum (Energy Information Administration 2010). A major change in regulation of greenhouse gas (GHG) emissions from the sector will, therefore, inevitably impact the markets. Such GHG regulations are already in effect in parts of Europe and North America, and more are expected in the near future. In Europe, the European Union Emissions Trading System (EU ETS) is well underway for its second phase from 2008 to 2012. In the United States, the effort has been concentrated on the regional or state level.[1] For example, California regulators adopted the nation's most comprehensive plan under the AB 32 Global Warming Solutions Act to curb carbon emissions using the cap-and-trade (C&T) model. On the East Coast of the US, the Regional Greenhouse Gas Initiative, in which ten states are participating, continues to be a forum for trading emissions allowances for electric utilities.

Regulations on limiting GHG emissions can be implemented through several market-based alternatives. Examples include renewable portfolio standards (RPS), GHG emissions tax, and C&T program. One of the strengths of these market-based instruments is their ability to couple with competitive electricity markets. Nevertheless, such interactions and their ultimate impact on the operation of the electricity markets as well as the environmental consequences must be carefully analyzed to avoid unintended adverse consequences.

In a perfectly competitive market, for instance, a carbon tax levied upstream on power plants would shift production toward low-carbon technologies such that total emissions should be reduced. Such intuition, however, may not hold when the behavior of strategic firms (owners of power plants) and demand response are taken into consideration. Under an emissions tax, these firms will face higher energy generation costs, and they will therefore alter their production schedules accordingly while taking into account emissions costs. In a locational marginal price (LMP)-based electricity markets, changes in energy outputs from plants at different locations might alleviate or intensify transmission congestion, thereby altering congestion patterns that possibly lead to some unintended consequences. For example, Downward (2010) illustrates through a stylized two-node system that overall carbon emission can increase after a carbon tax is imposed. When a carbon tax is levied on power plants, "cleaner" firms may become more competitive. Changes in the relative costs could eliminate congestion, thereby lowering energy prices. As a result, lower prices may induce higher electricity consumption, in effect lifting the overall carbon emissions. Even though this example represents a theoretical market anomaly, which may not be prevalent in practice, it highlights the need to consider the interactions and the potential unexpected consequences of environmental regulation in the electricity sector. Under the C&T approach, changes in a firm's output affect not only its marginal abatement cost,

[1] Although the outcome of the recent mid-term election might slow down the pace of a comprehensive federal energy and climate policy, the US Environmental Protection Agency (EPA) has planned on regulation of GHG emissions from coal-fired power plants through the new source performance standard under the Clean Air Act (Hughes 2010).

but also other firms' marginal costs through changes in the permit price (Kolstad and Wolak 2003). Since the market-based permit price can be unpredictable and volatile, the interaction of strategic behavior and C&T in the presence of transmission constraints can complicate the outcomes further.

In strategic models, the analysis of the impact induced by alternative regulatory mechanisms is complicated by the presence of transmission network. The inclusion of transmission constraints can result in surprising equilibria (Neuhoff et al. 2005). Although the effect of transmission constraints on strategic interactions in transmission networks has been studied extensively, the research on the impact of emissions regulation in power markets mainly consists of empirical studies (see e.g., Kolstad and Wolak 2003; Capros et al. 1998). One exception is by Chen and Hobbs (2005), who demonstrate how generators could manipulate the power market by using NO_x emissions permits.

While typical analyses of market power focus on small scale networks in order to gain insights into the interaction of firms (e.g. Cardell et al. 1997; Borenstein et al. 2000), we extend the analysis to a more realistic setting taking into account loop-flow and examine the effect of ownership and transmission constraints under the C&T policy. We employ an oligopoly equilibrium model in which generators behave strategically to maximize their profits. To make such a model computationally tractable, we employ a direct current (DC) approximation of the network, which is commonly used in analyses of market power in the electric industry (Wei and Smeers 1999; Pang et al. 2001).

This paper studies the impact of the carbon C&T policy through two test cases: the IEEE 24-bus[2] system and the Western Electricity Coordinating Council (WECC) 225-bus system. In the 24-bus test case, we calibrate our equilibrium results with Shao and Jewell (2010) in which the alternating current (AC) counterpart of this analysis is investigated under the assumption that the market is perfectly competitive. In addition, we use the WECC 225-bus system to simulate a realistic market that will allow us to gain insights into short-run equilibrium outcomes of the California market. This 225-bus system is a reduced representation of the WECC transmission system, which was also implemented in Yu et al. (2010) under an agent-based framework. In both test cases, we further simulate various scenarios to explore the policy impact on market outcomes in response to different levels of emissions cap and ownership structure of resources. We have three central findings in this paper. First, under a C&T program, a power market in which non-polluting resources are highly concentrated among a few players is subject to potential abuses of market power. Second, a higher level of market competition, together with a tight cap, affect the distribution of producer surpluses among producers as relatively polluting producers are no longer competitive under high carbon costs. Third, if non-polluting resources operating in a congested network are geographically concentrated, there arises the concern over potential abuses of market power in the procurement of clean energy through the permit market.

This paper is organized as follows. Section 2 presents a GHG-incorporated equilibrium model, including mathematical programming problems and equilibrium

[2] The term "bus" is used by power engineers to refer to a power system node (location). The terms—bus and location—are used interchangeably in this paper.

conditions of all market stakeholders. Section 3 outlines the calibration procedure for the AC model and scenario assumptions for the 24-bus system; Section 4 discusses economic implications of the system. Section 5 introduces the WECC 225-bus system and outlines various scenarios for an analysis, which is discussed in Section 6. Section 7 concludes.

2 Model

We introduce a GHG-incorporated equilibrium model that is a variant of the model proposed by Yao et al. (2008). This model is extended to account for GHG constraints by (1) associating emissions with the generation facilities and (2) coupling the equilibrium model with an emissions cap constraint. The price of permits is determined endogenously within the equilibrium framework by imposing a complementarity constraint[3] as a market clearing condition. We assume that the permit market is perfectly competitive with demand derived from the production decisions of electricity producers who behave as price-takers in the permit market.

To account for strategic behaviors and transmission constraints simultaneously, the equilibrium model is based on a lossless DC load flow model where transmission flows are constrained by thermal capacities of the lines. The flows in the system are governed by the Kirchhoff's laws through the Power Transfer Distribution Factors (PTDFs). The producers are Cournot players who own multiple generators competing to sell energy at different locations in an LMP-based market, where prices are set by the Independent System Operator (ISO). As Cournot players, producers maximize their profit by adjusting production levels given their respective residual demand, but they behave as price takers with regard to emission permit prices and locational congestion markups are set by the ISO. Consumers at each location are assumed to be price-takers and their demand is represented by a price-responsive inverse demand function.

For computational ease, a virtual location (bus) is created for each additional generator at those locations with multiple generators. These virtual locations are connected to their corresponding original location through a line with unlimited thermal capacities. Each location then has at most one generator. In what follows, we introduce notations used in the model and subsequently present the GHG-incorporated equilibrium model that describes the optimization problems faced by each entity.

Let N denote the set of buses (or locations) and L be the set of transmission lines whose elements are ordered pairs of distinct buses. Let G be the set of firms, and $N_g \subset N$ be the set of buses where generators owned by firm $g \in G$ are located. Let i and l be the elements in N and L, respectively. Note that by construction each i refers to bus i and also refers to the plant located at bus i, if a plant exists.

Let the fuel costs of plant $C_i(q)$ be a quadratic function of megawatt (MW) power output q defined as $C_i(q) = \frac{1}{2}s_i q^2 + c_i q, \forall i \in N$. The emission quantities of power plants are given by $F_i(q) = e_i q, \forall i \in N$, where e_i's are the emission rate of plant

[3] A complementarity constraint is defined as follows: $x \geq 0$, $f(x) \geq 0$, and $f(x)^T x = 0$, where $x \in R^n$ and the function $f : R^n \to R^n$ are given (Cottle et al. 1992). In this paper, we denote the orthogonality by $\perp$.

i. Consumers in each location i are represented by the inverse demand functions $P_i(q) = a_i - b_i q, \forall i \in N$, where a_i and b_i are constants.

2.1 ISO's problem

Formulation 2.1.1 expresses the optimization problem faced by the ISO. The ISO is assumed to maximize social surplus (1)—taking into account the output quantity decisions of the firms—subject to the lossless energy-balance constraint in the network (2), the transmission constraints (3), the non-negativity constraint (4), and the emission cap (5). By controlling power imports/exports at all locations (r_i's), the ISO can use shadow prices of the transmission constraints as a price signal corresponding to transmission congestions to control line flows. Line flows are simply a function of the import/export at all terminal locations, in which the MW flow on line l as a result of a MW transfer from location i to the reference location is measured by the PTDF, $D_{l,i}$. In addition, the flow on each transmission line l is constrained by its thermal limit K_l measured in MW in DC models.

In Formulations 2.1.1 and 2.2.1, the variables in parentheses next to the constraint are the Lagrange multipliers corresponding to that constraint. The Lagrange multiplier of (2), p, is the system marginal energy cost or price at the reference market. The Karush–Kuhn–Tucker (KKT) conditions of optimization problem 2.1.1 is summarized in 2.1.2. In particular, λ_l^+ and λ_l^- correspond to the shadow prices of the upper and lower transmission limits in (3), and ξ is the multiplier assigned to non-negative constraint (4). The variable φ_i, as written in (6), can then be represented as the sum of difference of λ_l^+ and λ_l^- over all the lines l weighted by the i-th row of the PTDF matrix minus ξ_i. In a sense, φ_i is the marginal congestion cost that reflects the cost contributions of the various transmission elements experiencing congestion associated with i, as measured between that bus i and the reference bus. Reflected by (7), the market clearing LMP at bus i is then $p + \varphi_i$, where the demand at location i is equal to the MW power generated by plant i plus the MW import, expressed by $q_i + r_i$. The load, $q_i + r_i$, must be non-negative because electricity is non-storable. The Lagrange multiplier μ corresponding to the emissions constraint reflects the price of carbon permits that the ISO will use as a penalty mechanism (see (9)) to suppress the emissions level when the cap constraint (5) is binding at M tons, and μ is also the price of carbon permits for any permit trading among energy producers.

2.1.1 Optimization

$$\max_{r_i : i \in N} \quad \sum_{i \in N} \int_0^{r_i + q_i} P_i(\tau_i) d\tau_i - C_i(q_i) \tag{1}$$

$$\text{s.t.} \qquad \sum_{i \in N} r_i = 0 \qquad (p) \tag{2}$$

$$-K_l \leq \sum_{i \in N} D_{l,i} r_i \leq K_l, \qquad (\lambda_l^-, \lambda_l^+) \quad \forall l \in L \tag{3}$$

$$r_i + q_i \geq 0, \qquad (\xi_i) \qquad \forall i \in N \tag{4}$$

$$\sum_{i \in N} F_i(q_i) \leq M, \qquad (\mu) \tag{5}$$

2.1.2 KKT conditions

$$\varphi_i = \sum_{l \in L} (\lambda_l^+ - \lambda_l^-) D_{l,i} - \xi_i, \qquad \forall i \in N \tag{6}$$

$$P_i(r_i + q_i) - p - \varphi_i = 0, \qquad \forall i \in N \tag{7}$$

$$\sum_{i \in N} r_i = 0, \tag{8}$$

$$0 \leq \lambda_l^- \perp \sum_{i \in N} D_{l,i} r_i + K_l \geq 0, \qquad \forall l \in L$$

$$0 \leq \lambda_l^+ \perp K_l - \sum_{i \in N} D_{l,i} r_i \geq 0, \qquad \forall l \in L$$

$$0 \leq \xi_i \perp r_i + q_i \geq 0, \qquad \forall i \in N$$

$$0 \leq \mu \perp M - \sum_{i \in N} F_i(q_i) \geq 0$$

2.2 Firms' problem

Each firm g considers the output of all other firms and optimally sets its own output so as to ultimately maximize its profits, expressed in (9), when facing a price-responsive demand curve. As for revenues represented by the first term of (9), firms earn $p + \varphi_i$ for each unit of energy generated at plant i as their competing outputs simultaneously determine the reference-bus marginal energy cost p, while treating the locational congestion markup φ_i, determined by the ISO, as exogenous. This assumption can be perceived as bounded rationality of firms and is credible when the network is not radial (Neuhoff et al. 2005). The costs of firm g are represented by the last two terms in (9): the total fuel costs and the emissions costs which include the opportunity cost of the permit price μ for each unit of emission. Constrained by minimum operating limit $(\underline{q}_i)$[4] and maximum operating limit $(\bar{q}_i)$ in (10), firms will vary outputs to maximize their profits, subject to the residual demand curve in which sales from other producers are treated as fixed. Modeling the firms' problem this way allows us to explore strategic interaction of firms as generation facilities of each firm are best responding to others throughout the system.

[4] The model abstracts from representing the startup, shut-down, ramping, and other non-convex costs that are typically considered in unit-commitment models. This implies that our approach of modeling fixed minimum production limits without possibilities of de-commitment may overestimate the emissions from these plants for which such limits are imposed. (We thank one anonymous referee for noting this.)

The KKT conditions in Formulation 2.2.2 imply the set of conditions for each firm g. Note that the residual demand constraint (11) can also be viewed as the market clearing condition (13), which can be written as $\sum_{i\in N} q_i = \sum_{i\in N}(P_i)^{-1}(p+\varphi_i)$, where the reference price p is implied by the joint production decisions of all the generators in the same way as the price in a conventional Cournot model.

2.2.1 Optimization

$$\max_{q_i:i\in N_g,p} \quad \sum_{i\in N_g}(p+\varphi_i)q_i - C_i(q_i) - \mu F_i(q_i) \tag{9}$$

$$\text{s.t.} \qquad \underline{q}_i \le q_i \le \bar{q}_i, \qquad (\rho_i^-, \rho_i^+) \quad \forall i \in N_g \tag{10}$$

$$\sum_{i\in N_g} q_i = \sum_{i\in N}(P_i)^{-1}(p+\varphi_i) - \sum_{i\in N\backslash N_g} q_i \quad (\beta_g) \tag{11}$$

2.2.2 KKT conditions

$$p+\varphi_i - \beta_g + \rho_i^- - \rho_i^+ - \frac{dC_i(q_i)}{dq_i} - \mu\frac{dF_i(q_i)}{dq_i} = 0, \qquad \forall i \in N_g$$

$$\beta_g \sum_{i\in N}\frac{d}{dp}(P_i)^{-1}(p+\varphi_i) + \sum_{i\in N_g} q_i = 0 \tag{12}$$

$$\sum_{i\in N} q_i = \sum_{i\in N}(P_i)^{-1}(p+\varphi_i) \tag{13}$$

$$0 \le \rho_i^- \perp q_i - \underline{q}_i \ge 0, \qquad \forall i \in N_g$$

$$0 \le \rho_i^+ \perp \bar{q}_i - q_i \ge 0, \qquad \forall i \in N_g$$

2.3 Equilibrium conditions

The market equilibrium conditions, consisting of all the KKT conditions for the ISO's and the firms' problems, constitute a mixed nonlinear complementarity problem. When ignoring the emissions trading, Yao et al. (2008) shows that the complementarity problem can be written in the form of a linear complementarity problem if the marginal cost functions and the inverse demand functions are linear. Extended to account for the emissions regulation, our market equilibrium conditions remain in the form of a linear complementarity problem because the emission functions are linear.

In equilibrium, the reference price p is determined simultaneously by all firms' decision on outputs. Equations (7) and (8) in the ISO KKT conditions imply the market clearing conditions (11) and (13). However, including (11) and thereby (13) in the generators' problem implies oligopoly behavior where the producers account for the effect of their joint decision on the reference price. In modeling perfect competition, all suppliers behave as price takers with respect to both the reference price and the

Table 1 Properties of generation units in the modified 24-bus system

Fuel type	Fuel costs ($/MMBtu)	CO_2 rate (lbs/MMBtu)	# of Units	Capacity (MW)
Oil	12	160	4	80
Gas	9.09	116	11	951
Coal	1.88	210	9	1,274
Hydro	0	0	6	300
Nuclear	0	0	2	800

locational congestion markups; thus, (11) and thereby (13) are removed, while (12) is replaced with $\beta_g = 0, \forall g \in G$, yielding the same result as a cost-minimizing dispatch model.

The inverse demand function at each bus is assumed to be linear with a price elasticity of -0.1. Although short-run elasticities are nearly zero, this level of elasticity is consistent with empirical studies (Azevedo et al. 2011). For computational purposes, we assume the existence of price-responsive demand at all locations, and hence the demand curve at a location with no load is set as almost vertical with the intercept being a very small positive number.

3 Case study: IEEE 24-bus system

The system has 24 buses, 38 transmission lines and transformers, and a total load of 2,850 MW. The total generation capacity is equal to 3,405 MW (Table 1).

We use a lossless DC approximation, although ignoring electrical resistance might alter flow patterns that could lead to different congestion patterns under some network topologies (Baldick 2003). As reported later in this section, the results obtained from the DC model, however, are fairly compatible with the AC model and, with proper calibration, provide a reasonable approximation for our purpose (which focuses on environmental policy). We outline the calibration procedure and report our results in the next subsection.

3.1 Calibration procedure and results

The calibration procedure begins with an optimization model—hereafter referred to as DC optimal power flow (OPF)—that minimizes the system-wide energy costs, subject to fixed locational demand, while satisfying constraints (2)–(5) and (10). The model yields the most cost effective way to produce energy to meet demand. The optimal outputs will take into account the cost of carbon permit, which is reflected in the form of the shadow price of the emissions cap constraint (5), determined endogenously by the model. The DC OPF model is identical to the equilibrium model under perfect competition assumption.

The test system is then modified to investigate the effects of C&T and strategic interaction of firms. The 951 MW of steam fossil oil is replaced with 951 MW of steam gas in order to explore the implication of the regulation. This modification is

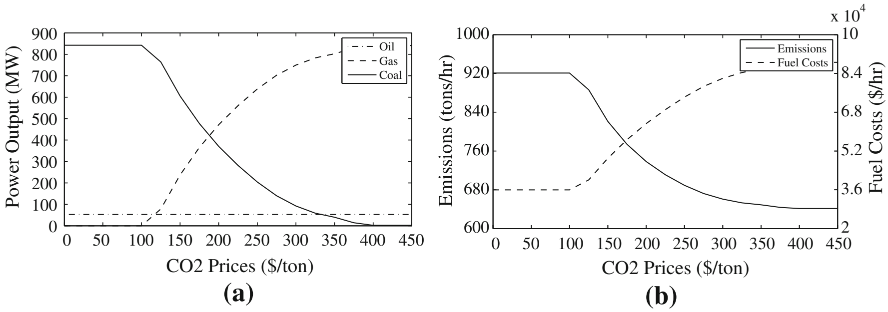

Fig. 1 Sensitivity analysis on CO_2 price. **a** Outputs by fuel types. **b** CO_2 emission and fuel costs

consistent with the work reported by Shao and Jewell (2010) which employs AC power flow framework under perfect competition.

Figure 1a shows the total power outputs (summing over all producers) of all fuel types. A must-run level is imposed on the oil power generation because an output that is lower than this level would yield negative marginal costs. As a result, the oil-fueled generation stays flat at its must-run level because the oil power generation is not optimally cost-effective to produce in this model. When the cap is not imposed nor it is binding, the emissions level under the DC OPF is at 921 tons/h, fairly comparable to what was reported by the AC OPF analysis (Shao and Jewell 2010). Furthermore, the sale-weighted average LMP is 16 \$/MWh, which is slightly lower than that of the AC OPF model, partly because the market experienced relatively lower transmissions congestion. Nevertheless, at CO_2 prices higher than 180 \$/ton, the sale-weighted average LMP is within 5% lower than that of the AC OPF model.

As shown in Fig. 1b, at a CO_2 price of 112 \$/ton, gas-fueled units begin to replace coal because the average marginal cost of gas power generation is 112.2 \$/MWh, which is cheaper than that of coal (i.e., 113 \$/MWh) when the CO_2 cost is considered. Therefore, when CO_2 price increases further, the higher price puts a downward pressure on the polluting coal units, causing a decline in total coal-fired power generation and the total CO_2 emission respectively. Although the AC OPF model gives a lower level of CO_2 price (70 \$/ton)[5] when merit order switch between gas and coal

[5] Theoretically, the level of CO_2 costs or threshold price that will lead to a switch of production order (coal vs. natural gas) is determined by the interplay of several factors: the difference in the relative fuel costs and emission rates as well as the network effects. The AC OPF model gives a CO_2 price of 70 \$/ton when the fuel switch occurs, and this price is within the range of what has been reported elsewhere (McKinsey and Company 2007). Without the transmission limits, however, the AC OPF model gives a much higher CO_2 price of 130 \$/ton. Typically, the threshold price is defined by arranging the production cost in ascending order without considering transmission congestion. However, in the presence of transmission congestion, identifying the threshold price is complicated because it requires rearranging production order by accounting for plants availability due to network effects when considering emissions costs. In the IEEE 24-bus case, low-emission facilities, which otherwise cannot export their energy when the network is congested, are allowed to replace high-emission facilities when transmission is ignored, effectively lowering the CO_2 price and elevating the CO_2 threshold price. Since the DC OPF assumes the same fuel cost and emission rate as the AC OPF, it implies that the difference in the CO_2 cost at which the fuel switch occurs between the two models is possibly because of the simplified representation of the transmission network in the DC OPF model without transmission losses.

Table 2 Market scenario description

Scenario[a]	Description
PC-32	Perfect competition with 32 firms in total
32F	Oligopoly with 32 firms in total: each firm owns only one facility
N/H-26	Oligopoly with 26 firms in total: one nuclear firm, one hydro firm, and 24 thermal firms
N/H-4	Oligopoly with 4 firms in total: one nuclear firm, one hydro firm, and two thermal firms
NH/G-3	Oligopoly with 3 firms in total: one firm owns all nuclear and hydro facilities, second firm owns all gas facilities, and the third firm owns all coal and oil facilities
NHG-2	Duopoly: one firm owns all clean facilities, i.e., nuclear, hydro, and gas while the other firm owns all coal and oil facilities
MP-1	Monopoly: all facilities belong to only one firm

[a] The number denoted in the name of each scenario represents the number of firms in each of them

plants occurs, the two models reach qualitatively similar conclusions as the reduction in coal outputs differs by less than 5%. For instance, when the permit price increases from 0 \$/ton to 180 \$/ton, the reduction in MWh output of coal power generation is 52% in the AC OPF model, compared with a 47% reduction in the DC OPF model. Therefore, we conclude that the AC and DC OPF produce comparable results and proceed to our oligopoly analysis in the next subsection.

3.2 Scenario assumptions

All analyses are performed on a 1-h basis because adding assumptions on time-variant loads would provide little insights to our purposes. In order to quantify the impact of the interaction of the energy market and the emissions market in a transmission-constrained network, we simulate various scenarios with different levels of emissions cap and changes in resource ownership. To investigate the effects more specifically, we set the emissions constraints at three cap levels: loose (1205 tons, 90% of no-cap case), moderate (815 tons, 60% of no-cap case), and extreme (515 tons, 38% of no-cap case). These levels are selected because they allow us to explore different market outcomes.

Table 2 presents seven different market scenarios along with detailed descriptions. Each scenario has an equal number of plants (32) but differs by the resource ownership structure. In PC-32 scenario, all firms are assumed to be perfectly competitive. Therefore, the different ownership (which firm owns what) does not lead to different market equilibria. Under the monopoly scenario (MP-1), all facilities are assumed to be owned by a single producer. The perfect competition (PC-32) and monopoly (MP-1) scenarios are used as benchmarks bounding other scenarios' equilibria.

The scenarios in Table 2 are ranked by their competitiveness from the most competitive (top, PC-32) to the least competitive one (bottom, MP-1) with respect to the number of firms in the market. The remaining five scenarios are Cournot–Nash oligopoly. They differ by their generation portfolios and ownership structures. In defining market scenarios, we use N, H and G to denote nuclear (2), hydro (6), and gas (11), respectively (the numbers in parenthesis denote the number of plants for each technology). We further group these technologies as clean technologies, hereafter referring to relatively low- or zero-carbon-emission technologies.

Table 3 Comparative statics: loose cap level (=1,205 tons)

	PC-32	32F	N/H-26	N/H-4	NH/G-3	NHG-2	MP-1
CO_2 emissions (tons)	1,060	1,205	1,205	942	833	765	370
Energy consumption (MWh)	2,160	2,000	1,924	1,702	1,599	1,452	1,086
Average LMP ($/MWh)	18	99	137	249	301	376	564
CO_2 price ($/ton)	0	12	66	0	0	0	0
CO_2 emissions rate (tons/MWh)	0.491	0.603	0.626	0.553	0.521	0.527	0.341
Congestion revenues (K$)	0	0	0	0	0	0	10
Total fuel costs (K$)	39	57	67	36	63	33	25
Productive inefficiencies (K$)	0	21	32	4	32	4	0

To begin with, the scenario 32F represents the most competitive Cournot case, where each firm owns one facility. In order to further explore the implications of concentrated ownership and technologies, market scenarios assume a variety of technology-ownership grouping. In N/H-26, one firm is assigned to own all the nuclear facilities and another one owns all the hydro facilities; the remaining 24 facilities ($32-2-6=24$) are owned by 24 firms. This scenario will provide insights into the market wherein two clean firms dominate many other small firms. Furthermore, we model the case where two clean firms (i.e., N (2) and H (6)) operate in a less competitive market by consolidating the rest of the market into two firms with comparable portfolios (N/H-4). To model even more extreme cases of the heterogeneity of technologies, the NH/G-3 and the NHG-2 scenarios assign all the facilities with clean technologies to one firm and the ones with dirty technologies to another. The only difference between these two scenarios is that NH/G-3 has an additional firm that owns all the gas facilities, thus separating this moderate carbon emission technology from the other clean ones.

4 Economic analysis of the 24-bus system

This section summarizes the economic analysis results. Tables 3, 4 and 5 summarize the comparative statics, including total CO_2 emissions, total energy consumption, average sale-weighted LMPs, permit price (CO_2 Price), CO_2 emissions rate, congestion revenues, system fuel costs, and productive inefficiencies. Figure 2 reports the shares of power generation by fuel types for scenarios under loose cap, moderate cap, and extreme cap. Table 6 shows the distribution of economic surpluses.

4.1 Electricity price

The average sale-weighted LMPs rise as the market becomes less competitive (fewer firms or more concentrated ownership), as shown from left to right in Tables 3, 4 and 5. Consequently, the rise in prices leads to the decline in energy generations (consumptions). Under a tighter emissions cap where the equilibrium LMPs tend to be higher, such market prices arise in the less demand-responsive portion of the demand curve.

Table 4 Comparative statics: moderate cap level (=815 tons)

	PC-32	32F	N/H-26	N/H-4	NH/G-3	NHG-2	MP-1
CO_2 emissions (tons)	815	815	815	815	815	765	370
energy consumption (MWh)	1,962	1,871	1,750	1,631	1,586	1,452	1,086
Average LMP ($/MWh)	123	164	225	286	308	376	564
CO_2 price ($/ton)	143	138	226	90	21	0	0
CO_2 emissions rate (tons/MWh)	0.415	0.436	0.466	0.500	0.514	0.527	0.341
Congestion revenues (K$)	48	0	0	0	0	0	10
Total fuel costs (K$)	46	56	68	34	62	33	25
Productive inefficiencies (K$)	0	17	35	2	31	4	0

The latter in turn grants higher market power to hydro, nuclear and gas facilities. For example, with the extreme cap, total hydro output in NH/G-3 is withheld by about 90% (=(300 − 27)/300) of its capacity (see Fig. 2). Also, the average LMP in NHG-2 is the highest among oligopolies (Tables 3, 4, 5) because the "clean" firm in NHG-2, under all cap levels, withholds more than 25% of its nuclear capacity to drive up prices.

4.2 Perfect versus oligopoly competition

Although energy consumption declines with rising market power and/or tighter cap, lower energy consumption does not always decrease the total emissions. Table 3 shows that the energy consumption is lower in the 32F scenario, as compared to the PC-32; however, the 32F results in higher emissions. This circumstance occurs because the 32F yields an inferior CO_2 emissions rate due to inefficient economic dispatch of resources, i.e., clean low-cost units (nuclear) are withheld and/or replaced with gas-fueled generation (referring to the loose-cap results in Fig. 2). As firms behave strategically, we can see that the system fuel costs are higher in 32F relative to PC-32, even though more energy (160 MWh more) is consumed in PC-32. To be precise, productive inefficiencies[6] show that the 32F is economically $ 21k less efficient if the demand was met under perfect competition. These results illustrate the inefficiency resulted from the strategic interaction of firms competing under the C&T policy.

4.3 Emissions permit price

In general, the permit price, which is determined by firms' production decision, should rise as the quantities demanded and the wholesale market becomes more competitive. Under certain market conditions, the permit price can create even greater incentive for clean firms to pursue strategic withholding. When clean technologies concentratedly owned by a few firms, these firms would withhold their production from relatively

[6] The productive inefficiencies indicate how much fuel costs in a scenario deviates from the most effective economic way to meet the same demand.

Table 5 Comparative statics: extreme cap level (=515 tons)

	PC-32	32F	N/H-26	N/H-4	NH/G-3	NHG-2	MP-1
CO_2 emissions (tons)	515	515	515	515	515	515	370
Energy consumption (MWh)	1,734	1,648	1,556	1,537	1,367	1,294	1,086
Average LMP ($/MWh)	249	288	323	333	419	456	564
CO_2 price ($/ton)	444	402	432	238	405	317	0
CO_2 emissions rate (tons/MWh)	0.297	0.312	0.331	0.335	0.377	0.398	0.341
Congestion revenues (K$)	171	91	0	0	0	0	10
Total fuel costs (K$)	67	61	64	56	49	28	25
Productive inefficiencies (K$)	0	1	10	5	18	1	0

cleaner resources in a way that allows production from more polluting resources to fill in the demand, effectively raising the demand for permits and driving up their LMPs (cf. Chen and Hobbs 2005). One example is that, under the extreme cap, even a coal firm operating in duopoly (NHG-2) is outcompeted by the clean firm because the permit price soars to 317 $/ton (Table 5; Fig. 2). The issue of strategic withholding could be aggravated further through its impact on the permit price if the rest of the market becomes more competitive, or if they possess little or no market power. In particular, Table 5 illustrates that the CO_2 price increases by 82% from 238 $/ton in N/H-4 to 432 $/ton in N/H-26 because the demand for permits increases as more of high-carbon fuels is burned (Fig. 2). In the extreme case (not shown) if most polluting resources are owned by price-taking firms, the permit price would be pushed upward even further.

4.4 Transmission constraints

The permit price is not only influenced by market power, but it is also adversely affected by transmission constraints. As shown in Table 6, the producer surplus in the 32F rises

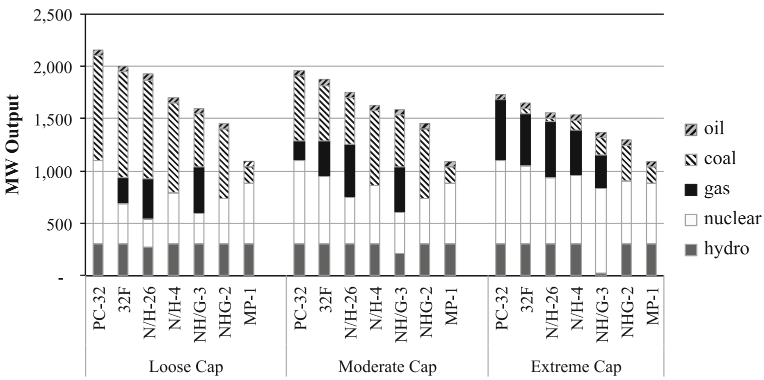

Fig. 2 Power outputs at different cap levels

Table 6 Economic results for the 24-bus system (in thousands of dollars)

	Cap	PC-32	32F	N/H-26	N/H-4	NH/G-3	NHG-2	MP-1
Social surplus	Loose	1,236	1,208	1,189	1,177	1,122	1,102	939
	Moderate	1,215	1,192	1,156	1,160	1,119	1,102	939
	Extreme	1,145	1,136	1,108	1,109	1,052	1,041	939
Consumer surplus	Loose	1,236	1,068	993	789	703	589	351
	Moderate	1,018	942	831	729	693	589	351
	Extreme	781	722	668	654	529	479	351
Producer surplus	Loose	−1	125	117	388	419	513	577
	Moderate	32	138	141	359	409	513	577
	Extreme	−35	116	217	333	315	399	577

slightly from \$ 125k to \$ 138k as the cap level changes from loose to moderate, but it unexpectedly plummets as the cap is tightened further to the extreme level—as opposed to an increase evidenced in the N/H-26. Unlike N/H-26, there are two nuclear firms in the 32F competing to produce electricity, leading to more congestion[7] (see Table 5), which eventually limits the nuclear access to the market. Consequently, the demand for permit grows, costing firms higher permit price in addition to congestion rents. This observation emphasizes how the interaction between a less competitive market and transmission network can influence the exercised market power under emissions cap, leading to various unintended consequences.

4.5 Economic surplus

At a fixed cap, Table 6 shows that consumer surplus declines as the number of firms decreases or ownership becomes concentrated. Meanwhile, in most cases, producer surplus increases as producers benefit from higher LMPs due to increasing market power. Overall, the increase in producer surplus is more than offset by the decline in consumer surplus, and the total social surpluses in all oligopolies fall within 10% as compared with their corresponding perfect competition case. As expected, producers benefit mostly in MP-1 at the expense of consumers. In fact, MP-1 gives the same equilibrium results across three levels of caps because the caps are non-binding. In contrast, the perfectly competitive market (PC-32) shows that some firms will no longer be profitable in equilibrium as suggested by the negative level of their producer surpluses. The negative producer surplus is attributable to the fact that some firms maintain its output at a must-run level even when the energy price is lower than their marginal cost.

[7] When there is no congestion in a network, the congestion revenues by default are equal to zero as no scarcity rent is associated with transmission.

Table 7 Resource mix of the WECC 225-bus system

Fuel type	Avg. MC[a] ($/MWh)	CO_2 (lbs/MWh)	# of units	Total MW	Percent
Hydro	7	0	6	10,842	23
Nuclear	9	0	2	4,499	10
Gas	70	1,281	23	26,979	57
Biomass	25	0	3	558	1
Geothermal	0	0	2	1,193	3
Renewable	0	0	1	946	2
Wind	0	0	3	2,256	5
			40	47,273	100

[a] *Source* Marginal costs, except for gas, are from Energy Information Administration, Annual Energy Outlook 2010, DOE/EIA-0383 (2009)

5 Case study: Western Electricity Coordinating Council (WECC) 225-bus system

In this section, we perform an equilibrium simulation on a realistic western 225-bus electricity system with real heat rate data and load data, based on the model introduced in Sect. 2.

5.1 Characteristics of the WECC 225-bus system

The system model represents the essentials of the California ISO (CAISO) area, which is composed of 293 transmission lines and 225 buses. Our simulated hour is the median of the hourly system load to represent the typical system condition. Of course, the permit price should be determined by the supply and demand condition over an extended time period, such as a typical compliance period of one year. Nevertheless, focusing on the 1-h analysis allows us to explore the market outcomes when producers respond to the C&T more aggressively.[8] Within the CAISO area, there are 23 aggregated thermal generators, 2 nuclear facilities, and a total of 15 aggregated hydroelectric and other renewable energy generators. The aggregated thermal generators have been grouped as “gas”, because gas is the predominant fuel. Table 7 summarizes the resource mix of this system.[9]

[8] Had the model been extended to an annual simulation, the permit price would be more elastic as producers are capable of coordinating their production decisions over extended periods. In fact, the model can be modified to account for annual simulations. For example, Chen and Hobbs (2005) presented a similar framework that allows the price of NO_x emission permits to be determined endogenously. However, coupling multiple periods would likely complicate our analyses with limited additional insights.

[9] For greenhouse gas such as CO_2, the constant emission rate is commonly used in modeling energy policies, e.g., IPM (Integrated Planning Model) used by U.S. Environmental Protection Agency (2011). In contrast, strong nonlinearity associated with output level for other air pollutants, e.g., NO_x (nitrogen oxides), is observed from a dataset provided by EPA CEMS (Environmental Protection Agency 2007). If the CO_2 emission rate was modeled as proportional to the quadratic fuel cost, it would discourage power plants from producing at a higher level since they would incur higher carbon costs.

Table 8 State average CO_2 emissions rate

Import state	CO_2 (lbs/MWh)
Arizona	1,219
Nevada	1,573
Oregon	456

Source eGRID2006 V2.1, April 2007

The net imports into the CAISO area are aggregated to several import points, i.e. Adelanto, El Dorado, Malin, Palo Verde, and Sylmar LA. In order to model the import supplies, we assume that each import point represents a competitive fringe with a price-responsive supply curve, which can be constructed using the same approach as the generation of the demand curves. To account for emissions, the state average CO_2 emission rates are used for imports (Table 8). The net exports to the Sacramento Municipal Utility District (SMUD)—a separate control area surrounded by the CAISO control area—are assumed to be electrical loads (electricity consumptions).

In addition to the thermal transmission constraints accounted for by Eq. 3 in Sect. 2.1, the CAISO enforces a list of additional transmission constraints, often referred to as "bubble constraint", to ensure reliable operation in the case of unpredictable generation contingencies in so-called "load pockets". The purpose of such constraints is to enable emergency imports into the load pockets. The list includes several groups of transmission lines (branch groups). Let S be the set of branch groups (BG) and L_s be the set of lines included in group $s \in S$. The BG constraints are expressed as follows:

$$0 \leq \omega_s \perp W_s + \sum_{l \in L} h_{s,l} \sum_{i \in N} D_{l,i} r_i \geq 0, \qquad \forall s \in S, \tag{14}$$

where W_s's are power limits; ω_s's are their Lagrange multipliers; and

$$h_{s,l} = \begin{cases} 1 \text{ if } l \in L_s \text{ and } l \text{ is defined in the same direction,} \\ -1 \text{ if } l \in L_s \text{ and } l \text{ is defined in the opposite direction,} \\ 0 \text{ if } l \notin L_s. \end{cases}$$

Accounting for these branch groups, the marginal congestion cost is then equal to

$$\varphi_i = \sum_{l \in L} (\lambda_l^+ - \lambda_l^-) D_{l,i} - \xi_i - \sum_{s \in S} \sum_{l \in L} \omega_s h_{s,l} D_{l,i}, \qquad \forall i \in N. \tag{15}$$

The last term of (15) reflects the additional cost of the branch groups that experience congestion. Hence, we add (14) to the equilibrium conditions and replace (6) with (15).

The owners and fuel types include aggregations of some owners and fuel types within each zone. The biggest non-investor-owned utility (non-IOU) owners are retained, and the others are aggregated into the IOUs' portfolio since many of them would actually be under the IOUs' contracts. In total, there are 10 aggregated owners (firms) and 1 competitive fringe representing imports into the CAISO.

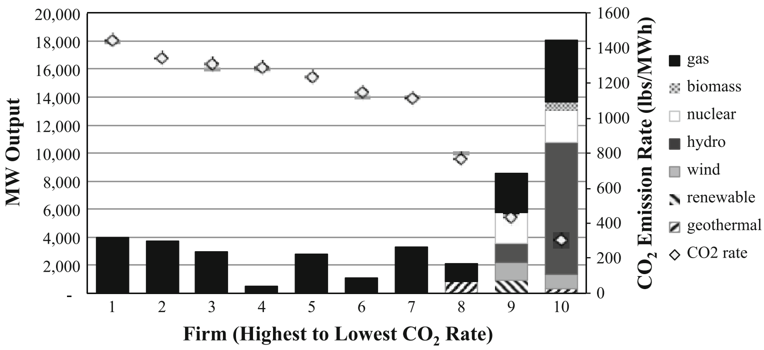

Fig. 3 Generation mix by firms in the WECC model

We define "dirtiness" of a firm by the capacity-weighted average of emissions rates of its available resources. Figure 3 displays the resource mix by firms that are ranked by their dirtiness from the highest rate (left) to the lowest rate (right). Clearly, the market is dominated by firms 9 and 10. The capacity-weighted Herfindahl–Hirschman Index[10] (HHI) of the market is 2,100, which is within the critical range between 1800 and 2500, suggesting moderate market concentration (Cardell et al. 1997).

5.2 Scenario assumptions

We simulate two market scenarios: perfect competition and oligopoly, where the impacts of transmission constraints are studied through the presence or absence of network constraints. In the absence of transmission constraints, we simply elevate the thermal limits of all transmission lines such that it is sufficient to decongest the network completely. Hence, we can examine the impact of the C&T program on the congestion-prone market as compared with the non-congested market (a market without transmission constraints). We further investigate the effects of binding emissions constraint by assuming that the emission target is set at 4,889 tons per hour, which is 20% below the CO_2 emission level corresponding to the no-cap transmission-constrained perfect competition case. The 20% was chosen to study the producers' response and market outcomes when the industry faces a stringent emission cap. In reality, the compliance schedule under a C&T policy is relatively loose at the beginning, and gradually ramps up to allow industries to respond by undertaking pollution controls or adopting clean technologies.

As aforementioned, the price-responsive demand functions are assumed to be linear with demand elasticity of -0.1. Similarly, the price-responsive supply functions for imports into California are assumed to be linear with supply elasticity of 0.005 (Tsao et al. 2011).

[10] The HHI provides a rough measurement of the scope and distribution of the horizontal market power.

Table 9 Comparative statics (with transmission constraints)

	Perfect competition			Oligopoly		
	No cap	Cap	Change (%)	No cap	Cap	Change (%)
CO_2 emissions (tons/h)	6,111	4,889	−20	9,766	4,889	−50
Energy consumption (MWh)	30,362	28,576	−6	28,060	25,040	−11
Average LMP ($/MWh)	59	94	60	97	154	59
CO_2 price ($/ton)	–	74		–	155	
CO_2 emissions rate (tons/MWh)	0.201	0.171	−15	0.348	0.195	−44
Import-only CO_2 rate (tons/MWh)	0.465	0.465	0	0.464	0.464	0

6 Economic analysis of the 225-bus system

This section summarizes the economic analysis results for the 225-bus system. Tables 9 and 10 report the total emissions, the total energy consumption, average LMP, CO_2 price, CO_2 emissions rate, and the import-only CO_2 emissions rate for scenarios with/without transmission constraints. Tables 11 and 12 display the social surplus, consumer surplus, producer surplus, congestion revenues, total carbon value, in-state fuel costs, and import costs for scenarios with/without transmission constraints, respectively. Figure 4 presents the equilibrium results of firm outputs, and Fig. 5 shows the equilibrium imports and generation outputs of all technologies.

As shown in Tables 9 and 10, the CO_2 cap raises the LMPs in all scenarios, leading to the reduction in energy consumption. For example, when the cap is imposed, the average LMP of the perfectly-competitive market with transmission constraints (Table 9) increases by 60% (from 59 $/MWh to 94 $/MWh), leading to a 6% drop in energy consumption. As expected, the cap induces lower emissions intensity in all scenarios. This suggests that electricity is on average produced by relatively less polluting resources. The CO_2 price reported in Table 9 is higher than what has been experienced in both the RGGI and EU ETS markets. The price reflects our assumption of a 20% reduction from the no-cap case under the perfect competition. Had the reduction been lower than 20%, the permit price would be more aligned with the actual market outcomes. As mentioned before, we intended to examine a stringent cap in order to understand the impact of the C&T policy on producers' responses and market outcomes.

Interestingly however, the impact of the cap is more pronounced in the oligopoly scenario when compared with the perfect competition scenario. In the oligopoly scenario with transmission constraints (Table 9), the average LMP is 64% (=(154 − 94)/94) higher; energy consumption declines 12% (=(25,040 − 28,567)/28,567); and emissions rate is 14% higher (=(0.195 − 0.171)/0.171), relative to the results of the perfect competition scenario. In an oligopoly market, the strategic withholding by dominant firms allows other polluting (higher-cost) competitors to increasingly fulfill demands and set higher LMPs. Because the dominant firms in this case possess a significant share of clean facilities, the permit market is indirectly influenced by strategic withholding. Had firms been allowed to exercise market power in the permit market, we

Table 10 Comparative statics (without transmission constraints)

	Perfect competition			Oligopoly		
	No cap	Cap	Change (%)	No cap	Cap	Change (%)
CO_2 emissions (tons/h)	4,977	4,889	−2	9,611	4,889	−49
Energy consumption (MWh)	30,471	30,286	−1	28,184	25,170	−11
Average LMP ($/MWh)	53	56	6	95	151	60
CO_2 price ($/ton)	–	8		–	151	
CO_2 emissions rate (tons/MWh)	0.163	0.161	−1	0.341	0.194	−43
Import-only CO_2 rate (tons/MWh)	0.464	0.464	0	0.464	0.464	0

would expect to see a greater impact of strategic withholding on permit prices. The incentive for the clean firms in such a case is to increase demand for permits and make them more valuable while they incur little, if not zero, emissions costs, thereby raising surpluses for their infra-marginal units.

One example illustrating how a dominant firm withholds its output and indirectly raises permit market prices is summarized as follows. When there is no carbon regulation, the dominant firm 10 withholds hydroelectric power and completely restricts its nuclear power in equilibrium, as illustrated in Fig. 4a. Once the carbon cap is imposed, firm 10 then operates more of the non-polluting facilities by increasing hydroelectric power. Nonetheless, firm 10 still withholds more than 30% of its generation relative to what it would generate in the perfectly-competitive market. Not only the firm withholds competitive gas-fired generation—as compared to the perfect competition scenario, but it also withholds a large portion of non-polluting capacity. This same behavior is also observed at firm 9. With this strategy, the carbon permits are indirectly used as an instrument to increase other competitors' marginal costs as they seek more permits, making some of the competitors uncompetitive and raising marginal prices. Figure 4a shows that a number of firms found it economically undesirable to generate electricity when the cap is implemented.

Under the C&T regulation, these differential effects of market outcomes between perfect competition and oligopoly are magnified if transmission constraints are not enforced. In the oligopoly scenario without transmission constraints (Table 10), the average LMP is 170% $(= (151 - 56)/56)$ higher; energy consumption is reduced by 17% $(= (25,170 - 30,286)/30,286)$; and emissions rate is 21% higher $(= (0.194 - 0.161)/0.161)$, relative to the results of the perfect competition scenario. The permit price in the congested oligopoly market (155 $/ton) is approximately the same as in the non-congested oligopoly market (151 $/ton), as opposed to a much lower price in the non-congested perfectly competitive market (8 $/ton). In particular, the absence of transmission constraints could enhance the outcomes of the perfectly-competitive market by making the market more accessible, increasing social surplus. Such market enhancements are less significant in the oligopoly scenario in this case, in part because the congestion level ($ 84k) is not as high as in perfect competition scenario ($ 379k), as shown in Table 11. Without congestion in the oligopoly market, firm 10 operates slightly more of its hydroelectric power to fulfill firm 3's generation that is no longer competitive in the non-congested market (see Fig. 4). Without the

Table 11 Economic results (with transmission constraints)

	Perfect competition			Oligopoly		
	No cap	Cap	Change (%)	No cap	Cap	Change (%)
In thousands of $						
Social surplus	10,386	10,348	0	9, 899	9, 968	1
Consumer surplus	8,945	7,905	−12	7, 839	6, 320	−19
Producer surplus	1,243	1,701	37	2, 038	2, 804	38
Congestion revenues	198	379	91	22	84	285
Total carbon value	–	364		–	760	
In-state fuel costs	347	245	−29	663	215	−68
Import costs	440	673	53	804	1,209	50

Table 12 Economic results (without transmission constraints)

	Perfect competition			Oligopoly		
	No cap	Cap	Change (%)	No cap	Cap	Change (%)
In thousands of $						
Social surplus	10,511	10,510	0	9,923	9,988	1
Consumer surplus	9,135	9,033	−1	7,906	6,400	−19
Producer surplus	1,376	1,437	4	2,017	2,849	41
Congestion revenues	–	–		–	–	
Total carbon value	–	40		–	738	
In-state fuel costs	235	225	−4	651	216	−67
Import costs	433	460	6	779	1,241	59

cap, firm 3 is competitive regardless of the presence of congestion. This result suggests the importance of network congestion effects on potential abuse of market power that may interact with the C&T policy.

As reported in Tables 11 and 12, the social surpluses remain relatively unchanged when the cap is imposed, while consumers generally suffer from higher LMPs. Consumers are most affected in the congested oligopoly market. Under the C&T, the producer surplus is the highest in the non-congested oligopoly market and the lowest in the non-congested perfectly-competitive market. Assuming a competitive market, the California market under the 20% emission-reduction target will be subjected to at least 50% increase in the costs of energy imports due to the rising LMPs, as a result of increased CO_2 costs.

Finally, as shown in Fig. 5, the emission reduction is mainly a result of the reduction in generation from polluting facilities if the market is perfectly competitive. In the oligopoly market, the emission reduction is, however, a simultaneous change in outputs from both polluting and non-polluting facilities. Unlike firms in a perfectly-competitive market, dominant firms in the oligopoly market are likely to withhold outputs from lower-marginal-cost facilities that are also less polluting. Once the cap

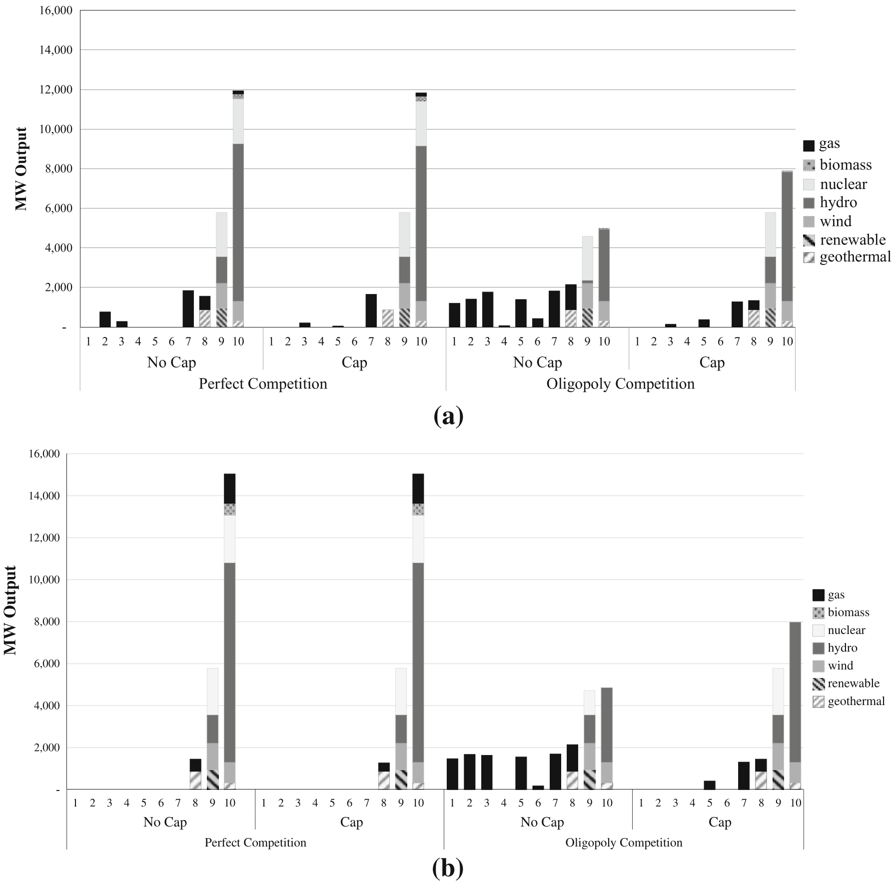

Fig. 4 Equilibrium results for outputs by firm. **a** With transmission constraints. **b** Without transmission constraints

is imposed, firms in the perfectly-competitive market may avoid carbon charges in the short run only by reducing outputs from polluting facilities as non-polluting resources have already operated at full capacity.

7 Conclusions

In this paper, we explore the strategic interactions among generators in a transmission-constrained network, under the additional constraint of pollution regulation. We focus on emission trading as the regulatory mechanism. We identify a potential gaming opportunity for a non-polluting generator that supplies power to a load pocket that has a limited access to alternative generators. The example raises concerns about inefficient transmission line utilization and suggests that efficient pollution regulation will require tight regulatory oversight on strategic behaviors. This is especially relevant to a state like California, where it is independently investing in in-state clean

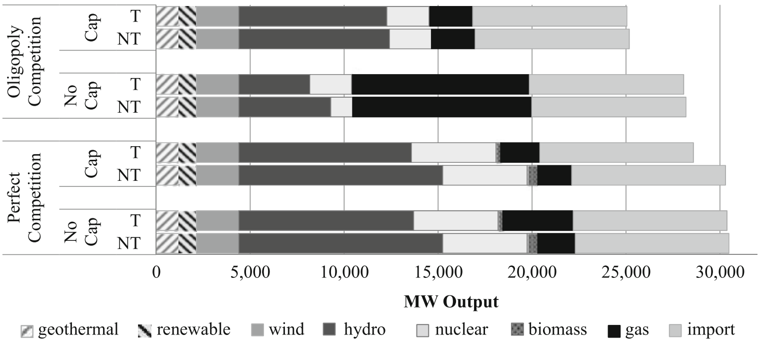

Fig. 5 Comparison of total equilibrium outputs by technology (T indicates the transmission-constrained network, and vice versa.)

generation and largely relying on importing residual energy from neighboring fossil fuel generators. A short-term equilibrium analysis of a cap-and-trade program in the transmissions-constrained electricity markets reveals that the ownership structure of producers might play a vital role in determining the economic and emissions outcomes. Here, we show that while a tightened cap might effectively constrain the total CO_2 emissions, resource ownership concentration could adversely interact with emissions policy and transmission constraints, leading to some unintended outcomes. Our main findings from the two analyses are summarized as follows. First, under a tighter emission cap and a higher degree of concentration of non-polluting electricity supplies, a power market is subject to potential abuses of market power. Second, a higher level of market competition, together with a tight cap, affects the distribution of producer surpluses among producers. Third, a transmission-constrained market, if clean resources are geographically concentrated, can lead to the potential abuses of market power in the procurement of clean energy through the permit market. Our approach, however, is subject to at least two limitations. First, we apply our model to 1-h analyses. The permit price should be determined by the supply and demand condition over an extended time period, such as a typical compliance period of one year, or over a longer period if banking and borrowing over years are considered. Second, we also focus our attention on an isolated C&T market which targets the electricity market alone. Given that the scope of a C&T policy could cover more than one sector, our approach may underestimate the price elasticity of emission permits, therefore inflating permit prices. One possible remedy is to incorporate a residual permit demand curve in our model. However, this will require information concerning the marginal abatement cost curves from other sectors. We leave these considerations to future research.

In summary, we have identified some counter-intuitive results that vary with respect to the network topology and ownership. Some outcomes are indeed related to the specifics regarding plant locations and technology types. However, the challenge faced by the government is that environmental regulation and market surveillance are subject to different regulatory entities—Environmental Protection Agency (EPA) and Federal Energy Regulatory Commission (FERC)—and, therefore, horizontal coordination among government agencies is needed to prevent abuse of market power from occurring. The strengths of the current framework include its flexibility to answer what-if type of questions by formulating scenarios and by generating various counterfactuals.

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