The Role of Energy Storage in Mitigating Ramping Inefficiencies Caused by Variable Renewable Generation

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Abstract

Rising penetrations of variable renewable generation in electric power systems can raise operational challenges. One is that renewables can increase the need for dispatchable generation with fast-ramping capabilities. This can be costly, because in many instances flexible generators can be more expensive than baseload units that have slower ramping capabilities. If ramping capacity is not available, renewable curtailment may be needed. An alternate solution to this need for ramping is to use energy storage.

A question that this raises is how renewable and conventional generators and energy storage would interact in a market environment, and whether certain asset-ownership structures would result in more efficient coordination. To this end, this paper presents a multi-period market-equilibrium model of interactions between these different types of market agents. The impacts on renewable integration of conventional generators having limited ramping capabilities are studied through an illustrative case study. We also examine a variety of structures for the participation of energy storage in the market. We find that co-ownership and co-operation of renewable generators and energy storage brings about the best results from the perspective of alleviating market inefficiencies. Having energy storage directly controlled by the market operator or participating as an independent profit-maximizing firm is less efficient.

Keywords: Electricity market, wind power, generator ramping, energy storage, equilibrium problem with equilibrium constraints

1. Introduction

The rising penetration of variable renewable generation sources is putting operational strains on electric power systems. As one example, there is a growing need for flexible dispatchable generation with fast-ramping capabilities to accommodate the variable and uncertain nature of real-time renewable-energy availability. Otherwise, renewable generation may be curtailed. This can be a costly proposition, however, because flexible generation units may have higher operating costs than less-flexible baseload units.

The literature studies numerous ways of mitigating the cost of ramping needs imposed by renewable generators. Three commonly studied approaches are to better predict and manage the cost of generator ramping needs [1–4], use demand response to engender demand-side flexibility [5–7], or use energy storage to meet ramping needs [8–13].

Analyses of the first approach includes the work of Kubik *et al.* [2], which examines the benefits of steps, such as fuel switching in conventional generators, to improve a power system's ramping capabilities and

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accommodate more renewable generation. Edmunds *et al.* [3] investigate the critical and growing role of natural gas-fired generation units in providing ramping capability to the British power system with increasing variable renewable generation. Zha *et al.* [4] propose a new approach to predicting the ramping needs of wind generation.

Studies of demand response include the work of Heydarian-Forushani *et al.* [5], which presents a stochastic network-constrained unit commitment model with demand response. Their model schedules both generating units and responsive loads in systems with high wind penetrations. Salpakari *et al.* [6] study the optimal control of electric heating systems as a source of flexible demand for renewable integration. Alahaivala *et al.* [7] also study flexible heating loads for wind integration and ramp mitigation. Their work suggests that heating loads could be utilized to reduce ramp rates, wind curtailment, and operational costs associated with severe ramps in wind availability.

Energy storage is a third option for increasing a power system's flexibility and ramping capability. There do remain, however, some challenges in adopting energy storage and in accommodating them within existing market designs. This reality has attracted studies focusing on the conflict between the technical benefits and the economic challenges in compensating energy storage for their services under current market designs [8, 14–16]. Despite this issue, a number of works examine the benefits of energy storage in accommodating renewables. O'Dwyer and Flynn [10] use a sub-hourly analysis to explore the role of energy storage in reducing operating costs and enhancing system efficiency and flexibility with high renewable penetrations. Khodayar *et al.* [11] propose an approach to determine the multi-period ramping capabilities of dispatchable generation resources. They further integrate energy storage to serve the ramping requirements imposed in the day-ahead electricity market by renewable generators. Heydarian-Forushani *et al.* [9] develop a robust optimization framework to optimize unit commitment decisions in systems with high penetrations of wind power. Their model incorporates demand response and bulk energy storage in co-optimized energy and reserve markets. Safaei *et al.* [17] introduce a novel compressed-air energy storage (CAES) system, wherein the waste heat of compression is reused for different heating demands through distributed compressors. They also compare the economics of their proposed distributed CAES to a traditional CAES system in a restructured electricity market, in which storage co-operates with wind generators. This co-operation allows the joint wind and CAES plants to participate like conventional dispatchable generators [18]. Hittinger *et al.* [19] propose a model in which a gas turbine, a wind generator, and fast-ramping energy storage are co-located and co-operating with each other to provide near-constant baseload power. Their proposed model is mostly suitable for isolated grids, due to the high energy-supply cost of their proposed hybrid energy system. Their method allows using significant amounts of wind generation, while reducing supply fluctuations to a small deadband.

These works leave some unanswered questions regarding the role of energy storage in mitigating ramping-related challenges surrounding renewable integration. The first are the potential interactions between strategic profit-maximizing behavior by renewable or conventional generators and supply-side flexibility. The second is the role of energy storage in mitigating flexibility issues. The third is the effect of market and asset-ownership structure on market efficiency and the ability of energy storage to mitigate ramping and flexibility issues. Answers to these questions would allow policy makers, market designers, and regulators to change market rules and structures to more efficiently accommodate high penetrations of renewable energy into electric power systems.

To this end, this paper presents a bi-level multi-period model of a spot-market equilibrium, which includes conventional and renewable generators and energy storage. The lower level of the problem represents the spot market being cleared by a market operator (MO). The MO's problem includes ramping constraints, which reflect generator flexibility. The upper level of the problem represents the decisions of the profit-maximizing generator and energy-storage firms in offering capacity to the market. The resulting bi-level problem is solved by first replacing the lower-level problem with its necessary and sufficient primal-dual optimality conditions. This gives a mathematical program with equilibrium constraints (MPEC) for each profit-maximizing firm. An equilibrium program with equilibrium constraints (EPEC) is obtained by combining all of the firms' MPECs. We employ a series of linearization techniques to recast the EPEC as a mixed-integer linear program (MILP). Solving this MILP gives candidate solutions that may be market equilibria. We use a diagonalization technique to determine which EPEC solutions are market equilibria, which are closely analyzed.

We demonstrate the proposed model using an illustrative case study. The case study also allows us to examine market interactions between conventional and renewable generators and energy storage under different asset-ownership and market structures. Specifically, we examine cases in which different firms behave as price-makers or price-takers. A price-taking firm is one that does not account for the impact of its offering behavior on market prices and dispatch levels. Thus, a price taker behaves competitively. A price-making firm, conversely, does take into account the impacts of its offers on market prices and dispatch. Thus, a price maker may opt to offer its generation strategically at a price that differs from marginal cost to impact its sales of energy or the price at which it is paid. We show that with strategic price-making firms, a market structure in which renewable generation and energy storage are co-owned is the most efficient in terms of accommodating renewable energy. Conversely, having energy storage directly controlled by the MO or participating as an independent profit-maximizing firm is less efficient.

This paper makes a number of contributions to the existing literature. First, we develop a multi-period bi-level market equilibrium model that can fully capture generator-ramping constraints and energy storage. Second, we convert the bi-level problem into an EPEC and recast it as an MILP, which can be tractably solved. Finally, we demonstrate the value of our model in being able to examine market interactions between conventional and renewable generation and energy storage under different market and asset-ownership structures. Our model can also examine different strategic behavior on the part of the participating firms.

The remainder of this paper is organized as follows. Section 2 provides more background on market-equilibrium, MPEC, and EPEC modeling. Section 3 provides an overview of our bi-level model. The appendices provide details on the steps that are taken to convert the bi-level model into a tractable MILP. Section 4 introduces our numerical case study and Section 5 summarizes our case study results. Section 6 concludes.

2. Market-Equilibrium, MPEC, and EPEC Modeling

This paper takes a complementarity-based approach to study market interactions between conventional and renewable generation and energy storage. Complementarity models are a powerful tool for modeling market interactions. The power of complementarity modeling lays in its ability to model the simultaneous optimization of multiple firms competing in a market [20]. In doing so, complementarity models allow computing market equilibria. For instance, Virasjoki *et al.* [12] use a Nash-Cournot model to analyze the effects of energy storage on ramping cost and congestion in a power system with renewable generators. Their analysis concludes that in a perfectly competitive market, energy storage helps to reduce congestion and ramping costs while potentially increasing greenhouse gas emissions from conventional generators. Conversely, they find that energy storage is less effective in mitigating congestion and ramping constraints in a market in which firms behave strategically. On the other hand, energy storage does not have the same negative impact on greenhouse gas emissions in a strategic setting.

An MPEC is an extension of a simple complementarity model that contains complementarity conditions in its constraint set. As such, an MPEC can represent more complex market interactions than a simple complementarity model can. Nasrolahpour *et al.* [13] propose an MPEC to make optimal operating decisions of price-making energy storage in a market. Their model considers uncertain output from wind generators and conventional generators that have limited ramping capabilities. Wang *et al.* [21] also employ an MPEC for optimizing the offering strategy of a merchant energy storage firm. Their analysis considers a ramp-constrained power system with high penetrations of renewable energy. Their model includes an additional day beyond the operating period being optimized, which attaches carryover value to energy stored at the end of the day [22, 23]. Because MPECs can model leader-follower games with only a single leader, the analyses of Nasrolahpour *et al.* [13] Wang *et al.* [21] assume that *only* energy storage behaves as a strategic profit-maximizer.

EPECs are a further and more complex extension of MPECs that are able to model leader-follower games with multiple leaders that are simultaneously behaving strategically (*e.g.*, maximizing profit). For example, Yaghooti *et al.* [24] use an EPEC to analyze the impacts of ramping limits on the strategic profit-maximizing behavior of multiple conventional-generator firms in an oligopolistic electricity market. Because the resulting EPECs are non-convex and non-linear equilibrium problems, Yaghooti *et al.* [24] employ a heuristic algorithm to solve the model. Moreover, their analysis does not consider renewable generation or energy storage. Moiseeva *et al.* [1] model the effects of ramping limits on strategic behavior in a market with wind generation. Their work employs a bi-level optimization problem, in which the ramp-constrained economic dispatch is the lower-level problem and the strategic generators' profit-maximizations are the upper-level problems. This yields an EPEC. Their work does not consider the impacts of energy storage, however.

A question raised in analyzing electricity markets is whether a model that captures strategic behavior is necessary. If an electricity market is relatively competitive, it is typically much easier from modeling and computational perspectives to assume perfect competition. Although electricity markets are subject to some oversight and mitigation, a number of empirical studies suggest that firms are able to behave strategically and exercise market power to varying degrees. Borenstein *et al.* [25] examine wholesale electricity price data from the early years of the California market. They show that over half of the increase in the cost of wholesale energy between the summers of 1999 and 2000 is attributable to the exercise of market power by generating firms. Sioshansi and Oren [26] and Hortaçsu and Puller [27] analyze the behavior of generating firms in the Texas market. They find evidence of strategic behavior whereby firms submit generation offers that are above cost to increase prices and profits. Willems *et al.* [28] conduct a similar analysis of the German wholesale electricity market, demonstrating the exercise of market power. In light of these and other findings, a modeling framework that captures strategic firm behavior is reasonable in analyzing market outcomes. Nevertheless, as discussed in Section 3.4, we examine a bounding range of market equilibria that vary between being highly competitive and highly uncompetitive. In doing so, we are able to show the extent to which the exercise of market power impacts the efficient use of energy storage in a market environment.

3. Modeling and Formulation of Market-Equilibrium Problem

Our model supposes that the market consists of a collection of firms, each of which may own some combination of conventional and renewable generators and energy storage. These firms may also behave strategically, whereby they simultaneously and independently optimize their offers into the market to maximize their profits. These offers are then used by the MO to determine the dispatch of the various units and market prices. The MO uses a multi-period market model, which captures intertemporal storage and generator-ramping constraints. A Nash equilibrium consists of a set of offers, and resulting prices and dispatch levels, from which no firm has a profitable unilateral deviation.

To maintain a tractable model we use a deterministic model that does not include transmission constraints. Linearized dc load-flow constraints could, however, be incorporated into our model, because they maintain linearity of the lower-level market model. Doing so would entail a computational cost, however.

We proceed in this section by first introducing model notation in Section 3.1. We then formulate the lower-level market model and the bi-level profit-maximization of the competing firms in Sections 3.2 and 3.3, respectively. We then discuss, in Section 3.4, the Nash equilibrium concept that is used in our analysis of market equilibria.

We defer all of the technical details of how the market-equilibrium problem is formulated and solved to the appendices. More specifically, Appendix A discusses the steps that are taken to convert each firm's bi-level profit-maximization problem into an MPEC. Appendix B and Appendix C show the steps that are taken to combine the MPECs of all of the firms to obtain an EPEC, which can be used to find candidate Nash equilibria. Appendix D details the steps that we take to linearize the EPEC. Finally, Appendix E discusses how we verify whether an EPEC solution is indeed a Nash equilibrium.

3.1. Nomenclature

The notation that is used in the proposed model is as follows:

3.1.1. Sets and Indices

B	number of blocks for demand, generation, and storage bids and offers.
P	set of firms.
T	number of hours in model horizon.
Δ_p^G	set of conventional units that are owned by firm p.
Δ_p^S	set of storage units that are owned by firm p.
Δ_p^W	set of renewable units that are owned by firm p.

3.1.2. Parameters

$C_{x,b}$	marginal cost of generation block b of conventional unit x.
$\bar{D}_{t,b}$	hour-t maximum demand in demand block b.
$\bar{E}_x$	maximum storage capacity of storage unit x.
$\bar{G}_{x,b}$	capacity of generation block b of conventional unit x.
R_x^U	ramp-up limit of conventional unit x.
R_x^D	ramp-down limit of conventional unit x.
$\bar{S}_{x,b}^C$	charging capacity of block b of storage unit x.
$\bar{S}_{x,b}^H$	discharging capacity of block b of storage unit x.
$U_{t,b}$	marginal utility of demand block b in hour t.
$\bar{W}_{t,x,b}$	hour-t available generation from block b of renewable unit x.
η_x^C	charging efficiency of storage unit x.
η_x^H	discharging efficiency of storage unit x.

3.1.3. Lower-Level Variables

$D_{t,b}$	hour-t demand of demand block b that is satisfied.
$E_{t,x}$	ending hour-t storage level of storage unit x.
$G_{t,x,b}$	hour-t dispatch of block b of conventional unit x.
$S_{t,x,b}^C$	hour-t energy charged in block b of storage unit x.
$S_{t,x,b}^H$	hour-t energy discharged from block b of storage unit x.
$W_{t,x,b}$	hour-t dispatch of block b of renewable unit x.

3.1.4. Upper-Level Variables

$O_{t,x,b}^C$	hour-t bid price for charging block b of storage unit x.
$O_{t,x,b}^H$	hour-t offer price for discharging block b of storage unit x.
$O_{t,x,b}^G$	hour-t offer price for block b of conventional unit x.
$O_{t,x,b}^W$	hour-t offer price for block b of renewable unit x.

3.2. Market Operator's Market Model

The MO's market model takes the offers of the firms as fixed and determines how to dispatch the various units to maximize social welfare (the model is formulated as a minimization problem, thus the objective function is negative social welfare). In the course of solving the market model, the MO determines both dispatch levels and market prices.

The MO's problem is formulated as:

$$\min \sum_{t,x,b} \left(O^G_{t,x,b} G_{t,x,b} + O^W_{t,x,b} W_{t,x,b} + O^H_{t,x,b} S^H_{t,x,b} - O^C_{t,x,b} S^C_{t,x,b}\right) - \sum_{t,b} U_{t,b} D_{t,b} \tag{1}$$

$$\text{s.t.} \sum_{x,b} \left(G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b}\right) = \sum_b D_{t,b}, \quad \forall t \qquad (\psi_t) \tag{2}$$

$$0 \le G_{t,x,b} \le \bar{G}_{x,b}, \quad \forall t,x,b \qquad (\theta^{G,-}_{t,x,b}, \theta^{G,+}_{t,x,b}) \tag{3}$$

$$0 \le W_{t,x,b} \le \bar{W}_{t,x,b}, \quad \forall t,x,b \qquad (\theta^{W,-}_{t,x,b}, \theta^{W,+}_{t,x,b}) \tag{4}$$

$$0 \le D_{t,b} \le \bar{D}_{t,b}, \quad \forall t,b \qquad (\theta^{D,-}_{t,b}, \theta^{D,+}_{t,b}) \tag{5}$$

$$-R^D_x \le \sum_b \left(G_{t,x,b} - G_{t-1,x,b}\right) \le R^U_x, \quad \forall t,x \qquad (\theta^{R,-}_{t,x}, \theta^{R,+}_{t,x}) \tag{6}$$

$$0 \le S^C_{t,x,b} \le \bar{S}^C_{x,b}, \quad \forall t,x,b \qquad (\theta^{C,-}_{t,x,b}, \theta^{C,+}_{t,x,b}) \tag{7}$$

$$0 \le S^H_{t,x,b} \le \bar{S}^H_{x,b}, \quad \forall t,x,b \qquad (\theta^{H,-}_{t,x,b}, \theta^{H,+}_{t,x,b}) \tag{8}$$

$$0 \le E_{t,x} \le \bar{E}_x, \quad \forall t,x \qquad (\theta^{E,-}_{t,x}, \theta^{E,+}_{t,x}) \tag{9}$$

$$E_{t,x} = E_{t-1,x} + \sum_b \left(\eta^C_x S^C_{t,x,b} - S^H_{t,x,b}/\eta^H_x\right), \quad \forall t,x \qquad (\theta^E_{t,x}) \tag{10}$$

$$E_{T,x} = E_{0,x}, \quad \forall x \qquad (\theta^{E,0}_x) \tag{11}$$

where the dual variable associated with each constraint appears in parentheses to its right. The decision variables of the MO's problems are all of the dispatch-related variables—$G_{t,x,b}$, $W_{t,x,b}$, $S^H_{t,x,b}$, $S^C_{t,x,b}$, $E_{t,x}$, and $D_{t,b}$.

Objective function (1) of the lower-level problem maximizes social welfare (as noted before, the MO problem is formulated as a minimization, thus the objective function measures negative social welfare). Constraints (2) impose hourly balance between supply and demand. The dual variables, ψ_t, associated with these constraints give hourly market-clearing prices for energy. Constraints (3) and (4) limit the dispatched output from each block of each conventional and renewable generator, respectively. Likewise, constraints (5) limit the cleared demand in each block based on maximum demand. Constraints (6) impose ramping limits on conventional generators.

Constraints (7)–(9) enforce limits on charging power, discharging power, and state of charge, respectively, of storage units. Constraints (10) impose state-of-charge balance for the storage units. Constraints (11) require storage units to have the same level of stored energy at the end of the operating horizon as they begin with. Without such constraints, each storage unit would be left fully discharged at the end of the operating horizon. Thus, these constraints ascribe carryover value to energy that is left in storage at the end of the operating horizon [22, 23].

3.3. Firm Profit-Maximization Bi-Level Problem

Each firm, which may own some combination of conventional and renewable generation and energy storage, determines its offers (*i.e.*, values of $O^C_{t,x,b}$, $O^H_{t,x,b}$, $O^G_{t,x,b}$, and $O^W_{t,x,b}$ for the assets that it owns) to maximize its profits. This profit maximization is formulated as a bi-level problem, because it includes the MO's market model as a lower-level problem. The profit-maximization problem of firm p is formulated as:

$$\min \sum_{t,x\in\Delta^G_p,b} (C_{x,b} - \psi_t) G_{t,x,b} - \sum_{t,x\in\Delta^W_p,b} \psi_t W_{t,x,b} - \sum_{t,x\in\Delta^S_p,b} \psi_t \cdot \left(S^H_{t,x,b} - S^C_{t,x,b}\right) \tag{12}$$

$$\text{s.t. } O^G_{t,x,b} \ge O^G_{t,x,b-1}, \quad \forall t, x \in \Delta^G_p, b > 1 \qquad (\Phi^G_{p,t,x,b}) \tag{13}$$

$$O^W_{t,x,b} \ge O^W_{t,x,b-1}, \quad \forall t, x \in \Delta^W_p, b > 1 \qquad (\Phi^W_{p,t,x,b}) \tag{14}$$

$$O^C_{t,x,b} \ge O^C_{t,x,b-1}, \quad \forall t, x \in \Delta^S_p, b > 1 \qquad (\Phi^C_{p,t,x,b}) \tag{15}$$

$$O^H_{t,x,b} \geq O^H_{t,x,b-1}, \quad \forall t, x \in \Delta^S_p, b > 1 \qquad (\Phi^H_{p,t,x,b}) \tag{16}$$

$$(1)\text{–}(11), \tag{17}$$

where the Lagrange multiplier associated with each constraint appears in parentheses to its right.

Objective function (12) maximizes firm p's profits (as with the MO's problem, the objective is given in minimization form). Firm revenues are defined as the product of net energy sales (taking into account energy charged into and discharged from energy storage) and the wholesale energy price. As noted in Section 3.2, the hour-t wholesale energy price is given by the dual variable, ψ_t. For sake of simplicity, renewable generation and energy storage are both assumed to have zero marginal operating costs.

Constraints (13)–(16) impose monotonicity on the offers, which is a typical market rule. Constraint (17) embeds the MO's market model as the lower-level problem. This constraint is needed to determine the effect of firm p's offers on its dispatch (*i.e.*, the values of $G_{t,x,b}$, $W_{t,x,b}$, $S^H_{t,x,b}$, and $S^C_{t,x,b}$) and energy prices, ψ_t. This constraint results in the profit-maximization problem being bi-level.

3.4. Market Equilibrium

Figure 1 illustrates the bilevel nature of our proposed model. The bottom of the figure represents the MO's market-clearing problem. This problem takes as inputs supply offers from the firms and determines how each firm's generation and storage units are dispatched. The MO also determines market-clearing prices for energy in each hour. At the upper level, each firm solves a profit-maximization problem to determine how to offer the units that it owns to maximize its individual profit.

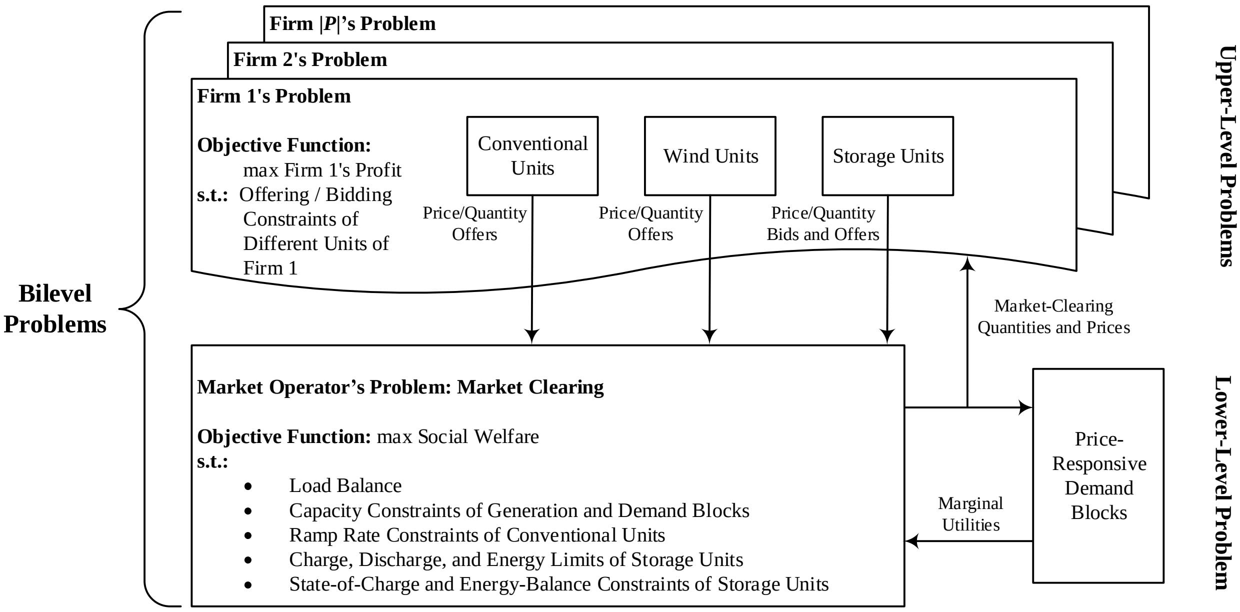

Figure 1: Schematic of Bilevel Model Structure and Market Equilibrium

The market equilibrium comes about because the firms simultaneously solve these profit maximization problems. Thus, each firm takes into account the profit-maximizing behavior of its rival firms and the impacts of these offer decisions (*i.e.*, its own and those of its rivals) on the dispatch levels and prices that are determined by the lower-level market model. We analyze the market by examining Nash equilibria. A Nash equilibrium is a set of offer decisions for the firms and dispatch levels and market-clearing prices that are simultaneously optimal in each firm's profit-maximization problem and the MO's market model. That is, no firm should have a profitable unilateral deviation from its strategies that are prescribed by the Nash equilibrium [29].

One difficulty in examining strategic games, such as the one that we propose, is that there may be multiple (or an infinite number of) Nash equilibria. We overcome this issue by examining a bounding range of Nash equilibria. These equilibria are obtained by imposing different objective functions on the EPEC that is used to find Nash equilibria. The first objective function:

$$\min \sum_{t,x,b} \left[C_{x,b} G_{t,x,b} - \psi_t \cdot (G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b}) \right],$$

maximizes total firm profits (keeping with the other model formulations, the objective function is written in minimization form). This objective function yields highly non-competitive equilibria, which we herein term 'collusive equilibria.' Although we term such equilibria 'collusive,' they do not represent truly collusive outcomes. A collusive outcome is typically not a Nash equilibrium, because players typically have incentives to unilaterally deviate from the set of strategies which maximize the joint profits of all of the firms.

The second objective function:

$$\min \sum_{t,x,b} C_{x,b} G_{t,x,b} - \sum_{t,b} U_{t,b} D_{t,b},$$

which is also written in minimization form, maximizes social welfare. This objective function yields highly competitive equilibria, which we herein refer to as 'quasi-competitive equilibria.' By using these two objective functions, we are able to examine extreme opposite cases in which the market outcome is highly competitive or non-competitive. Equilibria that occur in practice will likely lie between these two extremes. Thus, our analysis can be seen as illustrating the worst- and best-case scenarios, from a market-efficiency perspective.

Further details on how the market-equilibrium model is converted into a computationally tractable MILP are given in the appendices.

4. Case-Study Data

We demonstrate the use of our proposed model with an illustrative case study. The case study assumes a system with up to one wind generator, one storage device, and two conventional units. The wind and conventional generators are assumed to be owned by three independent profit-maximizing firms that compete with one another in the market. We examine cases in which storage is owned by an independent price-taking firm, an independent profit-maximizing firm, and the wind-generation firm.

To manage the computational complexity of the resulting EPEC, we consider eight operating hours in the case study. This is mainly because our analysis considers a number of cases with different asset-ownership and market structures. Given the volume of cases that we examine, having a case study with relatively short computational times is important. The eight-hours cases that we examine require up to 15 hours to solve. For purposes of comparison, we examine a small subset of 24-hour cases studies. In some instances, these cases require up to 70 hours of computation time. This testing shows that 24-hour case studies could be employed, however with some computational cost. Indeed, if one is examining the efficiency impacts of energy storage in a particular market setting, a more detailed analysis using a 24-hour case study may be prudent. On the other hand, our examination of 24-hour case studies reveal that the 'qualitative' properties of the market equilibria that we derive from the eight-hour cases all carry over to the 24-hour case studies. This suggests that our case-study results are robust to the duration of the operating period. It also suggests that additional insights may not be gleaned from 24-hour case studies. It is, finally, worth noting that use of a high-performance computing environment (to which we do not have access) would easily accommodate a larger model size. We, conversely, conduct our simulations using a laptop with limited memory and processing power.

Table 1 summarizes the characteristics of the two conventional units, each of which is assumed to have two generation blocks with different marginal costs. Generating unit 1 is relatively low-cost (compared to unit 2), but has a low ramping limit. As such, this generator represents an inflexible baseload unit. Conversely, generating unit 2 is relatively high-cost but has a high ramping limit, representing a flexible peaking plant. The storage unit is assumed to have 100 MW and 100 MWh power and energy capacities, respectively, an 85% round-trip efficiency, and an initial storage level of 50 MWh (which, per constraint (11), must also be the ending storage level).

Table 1: Conventional-Generator Characteristics

Unit	$\bar{G}_{x,1}$	$\bar{G}_{x,2}$	R_x^D	R_x^U	$C_{x,1}$	$C_{x,2}$	$G_{0,x}$
1	150 MW	150 MW	40 MW/h	50 MW/h	$20/MWh	$30/MWh	170 MW
2	75 MW	75 MW	80 MW/h	100 MW/h	$50/MWh	$60/MWh	70 MW

Figure 2 summarizes demand-related data. As the figure shows, the demand is assumed to be bid in three blocks. The bars in the figure represent the prices at which the three blocks are bid. The first block is offered at a relatively high price (meaning that this load is almost always served), while the other blocks have comparably lower bid prices. The hour-t maximum potential demand is defined as:

$$\sum_b \bar{D}_{t,b}.$$

The figure shows that the maximum potential demand follows a cycle that would normally be observed over the course of several hours, with off- and on-peak periods. The prices of the demand blocks are positively associated with maximum potential demand, reflecting the reality that willingness-to-pay for energy is typically higher during on-peak periods.

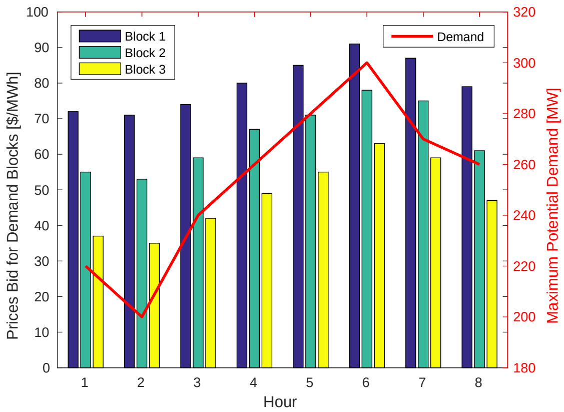

Figure 2: Prices Bid for Demand Blocks and Maximum Potential Demand in Each Hour

Figure 3 summarizes wind availability in each hour. With a peak availability of 120 MW, wind penetration is relatively high in this system when contrasted with the load data that are shown in Figure 2. Wind availability varies considerably from hour to hour, meaning that system flexibility is needed to maintain real-time balance between demand and supply. Moreover, wind availability is negatively correlated with demand, which is common in many power systems.

Table 2 summarizes the 18 cases that we examine. The cases differ in terms of how wind, energy storage, and conventional generators participate in the market. Case 1 assumes that there is no wind generation, while Cases 2–5 and 6–9 assume that there is a price-taking and price-making wind-generation firm, respectively. In the price-taking cases the generator offers its capacity into the market at its true marginal cost, which is assumed to be zero for the wind generator. In the price-making cases the wind generator can offer its supply at a different price than its true marginal cost (with the aim of maximizing its profits).

Cases 1, 2, and 6 assume that there is no energy storage in the system. Cases 3 and 7 assume that there is a standalone price-taking firm that owns the energy storage. In these cases, the energy storage is

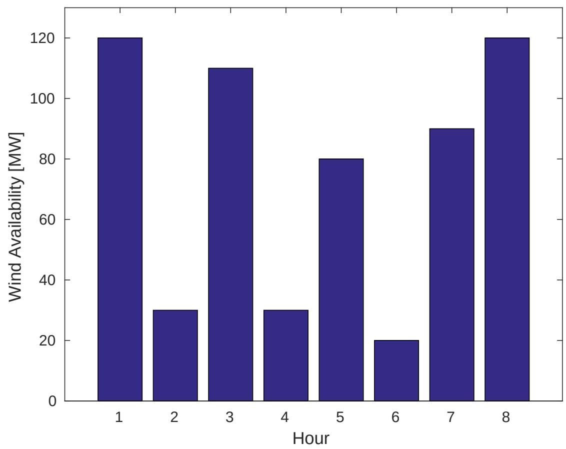

Figure 3: Wind Generation Available in Each Hour

Table 2: Cases Examined

Case	Wind	Storage	Generator-Ramping Constraints
1-NR	None	None	Relaxed
1-R	None	None	Enforced
2-NR	Price-Taking	None	Relaxed
2-R	Price-Taking	None	Enforced
3-NR	Price-Taking	Price-Taking	Relaxed
3-R	Price-Taking	Price-Taking	Enforced
4-NR	Price-Taking	Price-Making	Relaxed
4-R	Price-Taking	Price-Making	Enforced
5-NR	Price-Taking	Wind-Operated	Relaxed
5-R	Price-Taking	Wind-Operated	Enforced
6-NR	Price-Making	None	Relaxed
6-R	Price-Making	None	Enforced
7-NR	Price-Making	Price-Taking	Relaxed
7-R	Price-Making	Price-Taking	Enforced
8-NR	Price-Making	Price-Making	Relaxed
8-R	Price-Making	Price-Making	Enforced
9-NR	Price-Making	Wind-Operated	Relaxed
9-R	Price-Making	Wind-Operated	Enforced

offered into the market with zero charging and discharging costs. As a result, the MO operates the storage to minimize system operation costs. Cases 4 and 8 assume that there is a standalone price-making firm that owns the energy storage. In these cases, the energy-storage firm can offer at non-zero prices to maximize firm profits. The remaining two cases assume that the energy storage is co-owned and -operated by the wind-generation firm to maximize joint profits from wind and energy storage.

Conventional generation is assumed to be price-making in all of the cases. The cases that have an '-NR' suffix relax the ramping constraints on the conventional generators, whereas the cases that have an '-R' suffix enforce the constraints.

By contrasting results between the cases that are listed in Table 2, we are able to examine all interactions and impacts of different technologies and market structures. We analyze the impacts that the exercise of market power can have by comparing price-taking and -making cases. We can also examine interactions between technologies by comparing cases with and without wind and energy storage. Finally, comparing cases with the ramping constraints of conventional generators enforced and relaxed allows us to understand the impacts of these constraints on system operations.

5. Case-Study Results

Table 3 summarizes the results of the quasi-competitive market equilibria that are found in the 18 cases that are listed in Table 2. These equilibria are found by having the objective function of the EPEC maximize social welfare. Case 1-R, which has only two ramp-constrained conventional generators competing with one another, sees all of the load served by conventional unit 1, which is the lower-cost but less flexible generator. Case 2-R, in which the wind generator is added to the system as a price taker but there is no energy storage, has 5% of available wind energy and 2.5% of potential demand curtailed. Moreover, conventional unit 2, which is the higher-cost and more flexible generator, is dispatched. These changes are due to the limited ramping capability of conventional unit 1 and the greater variability in the net-load profile (*i.e.*, the profile given by the difference between load and available wind production). We demonstrate this impact of the limited ramping capability of conventional unit 1 by examining Case 2-NR, in which the ramping constraints are relaxed. There are no load or wind curtailments nor is conventional unit 2 dispatched in Case 2-NR. Hence, the combination of variable wind availability and limited ramping capabilities of conventional units results in higher-cost generation being dispatched, as well as wind and load curtailments.

Table 3: Results of Quasi-Competitive Market Equilibria

				Firm Profits [$]			
Case	Social Welfare [$]	Demand Met [%]	Wind Spillage [%]	Conventional Unit 1	Conventional Unit 2	Wind	Storage
1-NR	100220	100.0	n/a	51510	0	n/a	n/a
1-R	100220	100.0	n/a	51510	0	n/a	n/a
2-NR	117420	100.0	0.0	36740	0	24950	n/a
2-R	114650	98.5	5.0	30720	1120	21760	n/a
3-NR	117860	100.0	0.0	34648	0	25423	1000
3-R	117772	100.0	0.0	28862	0	23009	700
4-NR	117860	100.0	0.0	30274	0	23671	700
4-R	117772	100.0	0.0	30062	0	23489	700
5-NR	117860	100.0	0.0	34602	0	26720	98
5-R	117772	100.0	0.0	32987	0	25707	93
6-NR	117420	100.0	0.0	35520	0	26190	n/a
6-R	114650	98.5	8.3	38560	780	24800	n/a
7-NR	117860	100.0	0.0	34648	0	25423	1000
7-R	117772	100.0	0.0	28862	0	23009	700
8-NR	117860	100.0	0.0	30274	0	23671	700
8-R	117772	100.0	0.0	30062	0	23489	700
9-NR	117860	100.0	0.0	34602	0	26720	98
9-R	117772	100.0	0.0	32987	0	25707	93

Cases 3–5 examine the benefits of energy storage in mitigating the inefficiencies caused by limited ramping capabilities of the conventional generation units. Contrasting these cases with Case 2 shows that energy storage is able to alleviate wind and demand curtailment and the need to dispatch conventional unit 2, regardless of how the energy storage participates in the market (*i.e.*, as a price-taker, price-maker, or co-owned by the wind generator). This demonstrates the value of energy storage in allowing for more efficient wind integration when faced with generator-ramping constraints.

Among the cases in which the wind generator behaves as a price-maker (*i.e.*, Cases 6–9), only Case 6 has different results compared to the corresponding cases in which the wind generator behaves as a price-taker. In Case 6-R the wind generator's exercise of market power increases wind curtailment from 5% in Case 2-R to 8.3%. Consequently, the average energy price increases from about $43/MWh in Case 2-R to about $49/MWh in Case 6-R. There are corresponding increases in overall firm profits resulting from this wind curtailment. However, conventional unit 2 sees lower profits in Case 6-R compared to Case 2-R. Interestingly, the wind generator is unable to exercise market power in Cases 7–9, due to the presence of the energy storage. Hence, there are no wind or load curtailments in these cases and the equilibria are identical to the corresponding cases in which the wind generator behaves as a price-taker (*i.e.*, Cases 3–5).

As one might expect, the wind generator benefits overall from co-owning the energy storage (compared to cases in which storage is operated by an independent firm). Having energy storage co-owned by the wind generator also results in maximized total profits across all of the firms. We can also contrast equilibria in which the ramping constraints are relaxed and enforced. As expected, relaxing the ramping constraints increases social welfare, eliminates wind and load curtailments, and alleviates the need to dispatch conventional unit 2. Relaxing the ramping constraints also increases the profits of the wind generator.

Table 4 summarizes the results of the collusive market equilibria, which are obtained by maximizing total firm profits in the EPEC. As expected, these equilibria are not as competitive as those that are summarized in Table 3 are. The collusive equilibria see lower social welfare and higher firm profits compared to the quasi-competitive ones. For instance, in Case 1-R, which has only two ramp-constrained conventional units, only 73.4% of demand is served. Moreover, some of this load is served by conventional unit 2, as a result of conventional unit 1 withholding capacity to increase market prices. As such, the average energy price increases from about $50/MWh in the quasi-competitive equilibrium in Case 1-R to about $73/MWh in the collusive equilibrium. In Case 2-R, in which a price-taking wind generator is added, 5% of potential wind generation is curtailed, 81.8% of load served, and conventional unit 2 is further dispatched (compared to Case 1-R) because of the limited ramping capability of conventional unit 1.

Table 4: Results of Collusive Market Equilibria

				Firm Profits [$]			
Case	Social Welfare [$]	Demand Met [%]	Wind Spillage [%]	Conventional Unit 1	Conventional Unit 2	Wind	Storage
1-NR	87710	75.9	n/a	80160	0	n/a	n/a
1-R	83160	73.4	n/a	71720	1850	n/a	n/a
2-NR	102610	75.9	0.0	52020	0	43040	n/a
2-R	101440	81.8	5.0	40665	4145	33860	n/a
3-NR	102595	75.4	0.0	49837	0	42682	2041
3-R	101445	79.4	0.0	43905	1275	38300	3335
4-NR	102155	74.4	0.0	50244	0	43040	1321
4-R	102945	77.9	0.0	49184	0	38568	2045
5-NR	100972	73.7	0.0	50850	0	43040	−468
5-R	102082	77.2	0.0	49620	0	38840	972
6-NR	102610	75.9	0.0	52020	0	43040	n/a
6-R	100040	78.3	21.7	56780	0	30610	n/a
7-NR	102595	75.4	0.0	49837	0	42682	2041
7-R	100431	77.5	5.0	46711	850	36710	3335
8-NR	102155	74.4	0.0	50950	0	43040	615
8-R	98722	73.0	13.5	53410	0	37205	556
9-NR	100972	73.7	0.0	50850	0	43040	−468
9-R	102625	77.0	0.0	48860	0	38840	2275

Contrasting Case 2 to Cases 3–5 shows that in collusive equilibria energy storage has the same types of benefits as in quasi-competitive equilibria. This includes alleviating wind curtailment and reducing the dispatch of conventional unit 2. Although conventional unit 2 is dispatched if storage is price-taking, this unit is not dispatched if storage is price-making or co-owned by the wind generator.

Case 6-R sees higher wind curtailment rates compared to Case 2-R, as a result of the price-making wind generator exercising market power. As a result, the average energy price increases from \$63/MWh in Case 2-R to \$70/MWh in Case 6-R. Firm profits increase and social welfare decrease in Case 6-R (relative to Case 2-R). Interestingly, conventional unit 2 is not dispatched in Case 6-R, as a result of the wind generator's withholding of generation and the resulting reduced variability in the net-load profile. Among the three cases with energy storage and a price-making wind generator, the case in which storage is co-owned by the wind generator results in no wind curtailment and conventional unit 2 not being dispatched. Moreover, social welfare and the wind generator's profits are also maximized in Case 9-R, in which energy storage is co-owned by the wind generator.

Contrasting cases in which the ramping constraints are relaxed to those in which they are enforced shows that enforcing the ramping constraints results in lower overall profits for the firms. Moreover, there is no wind curtailment and conventional unit 2 is not dispatched in any of the cases in which ramping constraints are relaxed. This indicates that without ramping constraints, the wind generator is not able to profitably withhold supply from the market. Figure 4 further demonstrates the benefits of energy storage in reducing average energy-generation costs. The figure shows that the cases in which energy storage is co-owned by the wind generator (*i.e.*, Cases 5-R and 9-R) also have the lowest average energy-generation cost among all of the cases that are examined. Thus, co-ownership of wind and energy storage is beneficial in alleviating wind-integration and flexibility-related issues.

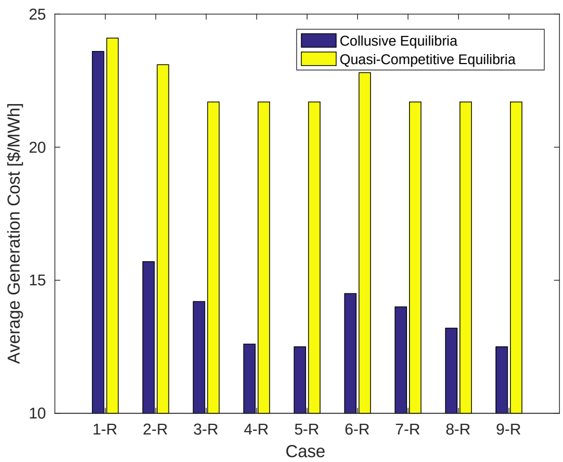

Figure 4: Average Generation Cost in Different Cases and Equilibria

All of the cases are formulated using GAMS version 24.2.1 and solved with Gurobi version 5.6.2 on a computer with a 2.26 GHz Intel Core 2 Duo processor and 2 GB of memory. The solution times of the quasi-competitive EPECs range between one and 63 minutes. The collusive EPECs take between one and 927 minutes to solve. The diagonalization process, which is used to verify that a given solution is indeed a Nash equilibrium (*cf.* Appendix E) also takes an additional one to five minutes of computing time.

6. Conclusion

This paper provides a framework to analyze market inefficiencies due to the integration of renewable generation in an electric power system. Our analysis specifically focuses on the impacts of ramping limits of conventional generators and the variability of wind production. We examine the use of energy storage as a means to address these inefficiencies. Importantly, the proposed model allows us to examine the interactions between these technologies within a market framework, and the potential for inefficiencies created by the exercise of market power or other strategic behavior on the part of generation or storage firms. The proposed model is an EPEC in which all firms can behave strategically to maximize their profits. The EPEC model is linearized (*cf.* the appendices), which yields a computationally tractable MILP.

We demonstrate the use of the proposed model with a simple illustrative case study. Within this case study we examine a variety of asset-ownership and market-participation structures. We also analyze in detail the effects of generator-ramping constraints on market outcomes. Our results show that variability in wind availability leads to system inefficiencies, including the dispatch of more expensive generation and load and wind curtailments. Energy storage is able to mitigate these inefficiencies, under a variety of asset-ownership structures. Our results show that co-ownership and -operation of energy storage by the wind generator yields the best results in terms of minimizing generation costs, maximizing wind-generation profits, minimizing wind curtailment, and minimizing the use of the high-cost peaking generator. This result may seem counter-intuitive, because one would assume that a price-taking energy storage firm would maximize market efficiency. However, this finding is consistent with other analyses of the welfare impacts of energy storage under imperfect competition [30, 31].

Our analysis does not consider the capital costs of energy storage devices and only examines short-run operational impacts. Comparing the capital costs of energy storage to the types of benefits that are examined in our work is an important consideration in long-run capacity planning. However, our proposed model is useful for understanding how conventional and renewable generators and energy storage interact and compete with one another under different market structures. For this reason, our proposed model is an important tool for policy makers, market designers, and regulators to examine market rules and structures. Our model can be employed to refine market designs with the aim of maximizing the efficient use of wind resources.

Acknowledgments

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Appendix A. Converting Firm Profit-Maximization Bi-Level Problem Into a Mathematical Program with Equilibrium Constraints

We can convert bi-level profit-maximization problem (12)–(17) into an MPEC. We do this by noting that the offer variables (*i.e.*, $O^C_{t,x,b}$, $O^H_{t,x,b}$, $O^G_{t,x,b}$, and $O^W_{t,x,b}$) are parameters in the lower-level market model. Moreover, the market model is linear, continuous, and convex. Hence, an optimal solution to the lower-level problem can be characterized by its primal/dual optimality conditions [32, 33], which are:

$$\sum_{x,b} \left(G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b}\right) = \sum_b D_{t,b}, \quad \forall t \qquad (\Psi_{p,t}) \qquad \text{(A.1)}$$

$$0 \le D_{t,b} \le \bar{D}_{t,b}, \quad \forall t, b \qquad (\Theta^{D,-}_{p,t,b}, \Theta^{D,+}_{p,t,b}) \qquad \text{(A.2)}$$

$$0 \le G_{t,x,b} \le \bar{G}_{x,b}, \quad \forall t, x, b \qquad (\Theta^{G,-}_{p,t,x,b}, \Theta^{G,+}_{p,t,x,b}) \qquad \text{(A.3)}$$

$$-R^D_x \le \sum_b \left(G_{t,x,b} - G_{t-1,x,b}\right) \le R^U_x, \quad \forall t, x \qquad (\Theta^{R,-}_{p,t,x}, \Theta^{R,+}_{p,t,x}) \qquad \text{(A.4)}$$

$$0 \le W_{t,x,b} \le \bar{W}_{t,x,b}, \quad \forall t, x, b \qquad (\Theta^{W,-}_{p,t,x,b}, \Theta^{W,+}_{p,t,x,b}) \qquad \text{(A.5)}$$

$$0 \le S^C_{t,x,b} \le \bar{S}^C_{x,b}, \quad \forall t, x, b \qquad (\Theta^{C,-}_{p,t,x,b}, \Theta^{C,+}_{p,t,x,b}) \qquad \text{(A.6)}$$

$$0 \le S^H_{t,x,b} \le \bar{S}^H_{x,b}, \quad \forall t, x, b \qquad (\Theta^{H,-}_{p,t,x,b}, \Theta^{H,+}_{p,t,x,b}) \qquad \text{(A.7)}$$

$$E_{t,x} = E_{t-1,x} + \sum_b \left(\eta^C_x S^C_{t,x,b} - S^H_{t,x,b}/\eta^H_x\right), \quad \forall t, x \qquad (\Theta^E_{p,t,x}) \qquad \text{(A.8)}$$

$$0 \le E_{t,x} \le \bar{E}_x, \quad \forall t, x \qquad (\Theta^{E,-}_{p,t,x}, \Theta^{E,+}_{p,t,x}) \tag{A.9}$$

$$E_{T,x} = E_{0,x}, \quad \forall x \qquad (\Theta^{E,0}_{p,x}) \tag{A.10}$$

$$U_{t,b} - \psi_t + \theta^{D,-}_{t,b} - \theta^{D,+}_{t,b} = 0, \quad \forall t, b \qquad (\omega^{D}_{p,t,b}) \tag{A.11}$$

$$-O^G_{t,x,b} + \psi_t + \theta^{G,-}_{t,x,b} - \theta^{G,+}_{t,x,b} + \theta^{R,-}_{t,x} - \theta^{R,-}_{t+1,x} - \theta^{R,+}_{t,x} + \theta^{R,+}_{t+1,x} = 0, \quad \forall t < T, x, b \qquad (\omega^{G}_{p,t,x,b}) \tag{A.12}$$

$$-O^G_{T,x,b} + \psi_T + \theta^{G,-}_{T,x,b} - \theta^{G,+}_{T,x,b} + \theta^{R,-}_{T,x} - \theta^{R,+}_{T,x} = 0, \quad \forall x, b \qquad (\omega^{G}_{p,T,x,b}) \tag{A.13}$$

$$-O^W_{t,x,b} + \psi_t + \theta^{W,-}_{t,x,b} - \theta^{W,+}_{t,x,b} = 0, \quad \forall t, x, b \qquad (\omega^{W}_{p,t,x,b}) \tag{A.14}$$

$$O^C_{t,x,b} - \psi_t + \theta^{C,-}_{t,x,b} - \theta^{C,+}_{t,x,b} - \eta^C_x \theta^E_{t,x} = 0, \quad \forall t, x, b \qquad (\omega^{C}_{p,t,x,b}) \tag{A.15}$$

$$-O^H_{t,x,b} + \psi_t + \theta^{H,-}_{t,x,b} - \theta^{h,+}_{t,x,b} + \theta^E_{t,x}/\eta^H_x = 0, \quad \forall t, x, b \qquad (\omega^{H}_{p,t,x,b}) \tag{A.16}$$

$$\theta^E_{t,x} - \theta^E_{t+1,x} + \theta^{E,-}_{t,x} - \theta^{E,+}_{t,x} = 0, \quad \forall t < T, x \qquad (\omega^{E}_{p,t,x}) \tag{A.17}$$

$$\theta^E_{T,x} + \theta^{E,-}_{T,x} - \theta^{E,+}_{T,x} + \theta^{E,0}_{x} = 0, \quad \forall x \qquad (\omega^{E,0}_{p,x}) \tag{A.18}$$

$$\theta^{D,-}_{t,b}, \theta^{D,+}_{t,b} \ge 0, \quad \forall t, b \qquad (\Omega^{D,-}_{p,t,b}, \Omega^{D,+}_{p,t,b}) \tag{A.19}$$

$$\theta^{G,-}_{t,x,b}, \theta^{G,+}_{t,x,b} \ge 0, \quad \forall t, x, b \qquad (\Omega^{G,-}_{p,t,x,b}, \Omega^{G,+}_{p,t,x,b}) \tag{A.20}$$

$$\theta^{R,-}_{t,x}, \theta^{R,+}_{t,x} \ge 0, \quad \forall t, x \qquad (\Omega^{R,-}_{p,t,x}, \Omega^{R,+}_{p,t,x}) \tag{A.21}$$

$$\theta^{W,-}_{t,x,b}, \theta^{W,+}_{t,x,b} \ge 0, \quad \forall t, x, b \qquad (\Omega^{W,-}_{p,t,x,b}, \Omega^{W,+}_{p,t,x,b}) \tag{A.22}$$

$$\theta^{C,-}_{t,x,b}, \theta^{C,+}_{t,x,b} \ge 0, \quad \forall t, x, b \qquad (\Omega^{C,-}_{p,t,x,b}, \Omega^{C,+}_{p,t,x,b}) \tag{A.23}$$

$$\theta^{H,-}_{t,x,b}, \theta^{H,+}_{t,x,b} \ge 0, \quad \forall t, x, b \qquad (\Omega^{H,-}_{p,t,x,b}, \Omega^{H,+}_{p,t,x,b}) \tag{A.24}$$

$$\theta^{E,-}_{t,x}, \theta^{E,+}_{t,x} \ge 0, \quad \forall t, x \qquad (\Omega^{E,-}_{p,t,x}, \Omega^{E,+}_{p,t,x}) \tag{A.25}$$

$$\begin{aligned}
&\sum_{t,x,b} \left(O^G_{t,x,b} G_{t,x,b} + O^W_{t,x,b} W_{t,x,b} + O^H_{t,x,b} S^H_{t,x,b} - O^C_{t,x,b} S^C_{t,x,b}\right) - \sum_{t,b} U_{t,b} D_{t,b} \qquad \text{(A.26)} \\
&\quad = -\sum_{t,b} \bar{D}_{t,b} \theta^{D,+}_{t,b} - \sum_{t,x,b} \left(\bar{G}_{x,b} \theta^{G,+}_{t,x,b} + R^D_x \theta^{R,-}_{t,x} + R^U_x \theta^{R,+}_{t,x} + \bar{W}_{t,x,b} \theta^{W,+}_{t,x,b}\right) \\
&\quad + \sum_{x,b} G_{0,x,b} \cdot \left(\theta^{R,-}_{1,x} - \theta^{R,+}_{1,x}\right) - \sum_{t,x,b} \left(\bar{S}^C_{x,b} \theta^{C,+}_{t,x,b} + \bar{S}^H_{x,b} \theta^{H,+}_{t,x,b}\right) \\
&\quad + \sum_x \left(E_{0,x} \cdot \left(\theta^E_{1,x} + \theta^{E,0}_x\right) - \sum_t \bar{E}_x \theta^{E,+}_{t,x}\right), \qquad (\Omega^{\text{SD}}_p)
\end{aligned}$$

where the Lagrange multiplier associated with each constraint appears in parentheses to its right.

Conditions (A.1)–(A.10) are the primal constraints of the MO's problem, *i.e.*, they are the same as constraints (2)–(11). Conditions (A.11)–(A.25) are the constraints of the dual problem to the market model. Finally, (A.26) is the strong-duality condition, which ensures that the primal and dual objective functions are equal.

Thus, we convert firm p's bi-level profit-maximization problem into an MPEC by minimizing objective function (12) subject to constraints (13)–(16) and (A.1)–(A.26). That is, we replace the lower-level market model with its primal/dual optimality conditions.

Appendix B. Multi-Firm Nash Equilibrium

Our goal is to find Nash equilibrium offers for the firms, which satisfy the property that no firm has a profitable unilateral deviation. Another way of characterizing the no-unilateral-deviation property is that the offers must be simultaneously optimal in each firm's MPEC, which is given by (12)–(16) and (A.1)–(A.26). Thus, one way of finding Nash equilibria is by simultaneously solving the firms' MPECs. Because simultaneously solving these MPECs is intractable, we instead characterize potential optimal solutions to each firm's profit-maximization problem using the Karush-Kuhn-Tucker (KKT) conditions for the firm's MPEC. We can then find potential Nash equilibria by simultaneously solving the KKT conditions of all of the firms' MPECs.

The KKT conditions of firm p's MPEC are:

$$-\Phi^G_{p,t,x,b} + \Phi^G_{p,t,x,b+1} + \Omega^{\mathrm{SD}}_p G_{t,x,b} - \omega^G_{p,t,x,b} = 0, \quad \forall t, x \in \Delta^G_p, b < B \tag{B.1}$$

$$-\Phi^G_{p,t,x,B} + \Omega^{\mathrm{SD}}_p G_{t,x,B} - \omega^G_{p,t,x,B} = 0, \quad \forall t, x \in \Delta^G_p \tag{B.2}$$

$$-\Phi^W_{p,t,x,b} + \Phi^W_{p,t,x,b+1} + \Omega^{\mathrm{SD}}_p W_{t,x,b} - \omega^W_{p,t,x,b} = 0, \quad \forall t, x \in \Delta^W_p, b < B \tag{B.3}$$

$$-\Phi^W_{p,t,x,B} + \Omega^{\mathrm{SD}}_p W_{t,x,B} - \omega^W_{p,t,x,B} = 0, \quad \forall t, x \in \Delta^W_p \tag{B.4}$$

$$-\Phi^C_{p,t,x,b} + \Phi^C_{p,t,x,b+1} - \Omega^{\mathrm{SD}}_p S^C_{t,x,b} + \omega^C_{p,t,x,b} = 0, \quad \forall t, x \in \Delta^S_p, b < B \tag{B.5}$$

$$-\Phi^C_{p,t,x,B} - \Omega^{\mathrm{SD}}_p S^C_{t,x,B} + \omega^C_{p,t,x,B} = 0, \quad \forall t, x \in \Delta^S_p \tag{B.6}$$

$$-\Phi^H_{p,t,x,b} + \Phi^H_{p,t,x,b+1} + \Omega^{\mathrm{SD}}_p S^H_{t,x,b} - \omega^H_{p,t,x,b} = 0, \quad \forall t, x \in \Delta^S_p, b < B \tag{B.7}$$

$$-\Phi^H_{p,t,x,B} + \Omega^{\mathrm{SD}}_p S^H_{t,x,B} - \omega^H_{p,t,x,B} = 0, \quad \forall t, x \in \Delta^S_p \tag{B.8}$$

$$-\Psi_{p,t} + \Theta^{D,+}_{p,t,b} - \Theta^{D,-}_{p,t,b} - \Omega^{\mathrm{SD}}_p U_{t,b} = 0, \quad \forall t, b \tag{B.9}$$

$$C_{x,b} - \psi_t + \Psi_{p,t} + \Theta^{G,+}_{p,t,x,b} - \Theta^{G,-}_{p,t,x,b} + \Theta^{R,+}_{p,t,x} - \Theta^{R,+}_{p,t+1,x} - \Theta^{R,-}_{p,t,x} + \Theta^{R,-}_{p,t+1,x} + \Omega^{\mathrm{SD}}_p O^G_{t,x,b} = 0, \quad \forall t < T, x \in \Delta^G_p, b \tag{B.10}$$

$$C_{x,b} - \psi_T + \Psi_{p,T} + \Theta^{G,+}_{p,T,x,b} - \Theta^{G,-}_{p,T,x,b} + \Theta^{R,+}_{p,T,x} - \Theta^{R,-}_{p,T,x} + \Omega^{\mathrm{SD}}_p O^G_{T,x,b} = 0, \quad \forall x \in \Delta^G_p, b \tag{B.11}$$

$$\Psi_{p',t} + \Theta^{G,+}_{p',t,x,b} - \Theta^{G,-}_{p',t,x,b} + \Theta^{R,+}_{p',t,x} - \Theta^{R,+}_{p',t+1,x} - \Theta^{R,-}_{p',t,x} + \Theta^{R,-}_{p',t+1,x} + \Omega^{\mathrm{SD}}_{p'} O^G_{t,x,b} = 0, \quad \forall p' \neq p, t < T, x \in \Delta^G_{p'}, b \tag{B.12}$$

$$\Psi_{p',T} + \Theta^{G,+}_{p',T,x,b} - \Theta^{G,-}_{p',T,x,b} + \Theta^{R,+}_{p',T,x} - \Theta^{R,-}_{p',T,x} + \Omega^{\mathrm{SD}}_{p'} O^G_{T,x,b} = 0, \quad \forall p' \neq p, x \in \Delta^G_{p'}, b \tag{B.13}$$

$$-\psi_t + \Psi_{p,t} + \Theta^{W,+}_{p,t,x,b} - \Theta^{W,-}_{p,t,x,b} + \Omega^{\mathrm{SD}}_p O^W_{t,x,b} = 0, \quad \forall t, x \in \Delta^W_p, b \tag{B.14}$$

$$\Psi_{p',t} + \Theta^{W,+}_{p',t,x,b} - \Theta^{W,-}_{p',t,x,b} + \Omega^{\mathrm{SD}}_{p'} O^W_{t,x,b} = 0, \quad \forall p' \neq p, t, x \in \Delta^W_{p'}, b \tag{B.15}$$

$$\psi_t - \Psi_{p,t} - \Theta^{C,-}_{p,t,x,b} + \Theta^{C,+}_{p,t,x,b} - \eta^C_x \Theta^E_{p,t,x} - \Omega^{\mathrm{SD}}_p O^C_{t,x,b} = 0, \quad \forall t, x \in \Delta^S_p, b \tag{B.16}$$

$$-\Psi_{p',t} - \Theta^{C,-}_{p',t,x,b} + \Theta^{C,+}_{p',t,x,b} - \eta^C_x \Theta^E_{p',t,x} - \Omega^{\mathrm{SD}}_{p'} O^C_{t,x,b} = 0, \quad \forall p' \neq p, t, x \in \Delta^S_{p'}, b \tag{B.17}$$

$$-\psi_t + \Psi_{p,t} - \Theta^{H,-}_{p,t,x,b} + \Theta^{H,+}_{p,t,x,b} + \Theta^E_{p,t,x}/\eta^H_x + \Omega^{\mathrm{SD}}_p O^H_{t,x,b} = 0, \quad \forall t, x \in \Delta^S_p, b \tag{B.18}$$

$$\Psi_{p',t} - \Theta^{H,-}_{p',t,x,b} + \Theta^{H,+}_{p',t,x,b} + \Theta^E_{p',t,x}/\eta^H_x + \Omega^{\mathrm{SD}}_{p'} O^H_{t,x,b} = 0, \quad \forall p' \neq p, t, x \in \Delta^S_{p'}, b \tag{B.19}$$

$$\Theta^E_{p,t,x} - \Theta^E_{p,t+1,x} - \Theta^{E,-}_{p,t,x} + \Theta^{E,+}_{p,t,x} = 0, \quad \forall t < T, x \tag{B.20}$$

$$\Theta^E_{p,T,x} - \Theta^{E,-}_{p,T,x} + \Theta^{E,+}_{p,T,x} + \Theta^{E,0}_{p,x} = 0, \quad \forall x \tag{B.21}$$

$$-E_{0,x}\Omega^{\mathrm{SD}}_p + \sum_b \left(\omega^H_{p,1,x,b}/\eta^H_x - \eta^C_x \omega^C_{p,1,x,b}\right) + \omega^E_{p,1,x} = 0, \quad \forall x \tag{B.22}$$

$$\sum_b \left(\omega^H_{p,t,x,b}/\eta^H_x - \eta^C_x \omega^C_{p,t,x,b}\right) + \omega^E_{p,t,x} - \omega^E_{p,t-1,x} = 0, \quad \forall t \in \{2, \ldots, T-1\}, x \tag{B.23}$$

$$\sum_b \left(\omega^H_{p,T,x,b}/\eta^H_x - \eta^C_x \omega^C_{p,T,x,b}\right) + \omega^{E,0}_{p,x} - \omega^E_{p,T-1,x} = 0, \quad \forall x \tag{B.24}$$

$$-E_{0,x}\Omega^{\mathrm{SD}}_p + \omega^{E,0}_{p,x} = 0, \quad \forall x \tag{B.25}$$

$$-\sum_{x \in \Delta^G_p, b} G_{t,x,b} - \sum_{x \in \Delta^W_p, b} W_{t,x,b} - \sum_{x \in \Delta^S_p, b} \left(S^H_{t,x,b} - S^C_{t,x,b}\right) - \sum_b \omega^D_{p,t,b} + \sum_{x,b} \left(\omega^G_{p,t,x,b} + \omega^W_{p,t,x,b} + \omega^H_{p,t,x,b} - \omega^C_{p,t,x,b}\right) = 0, \quad \forall t \tag{B.26}$$

$$\omega^{D}_{p,t,b} - \Omega^{D,-}_{p,t,b} = 0, \quad \forall t, b \tag{B.27}$$
$$\bar{D}_{t,b}\Omega^{\text{SD}}_{p} - \omega^{D}_{p,t,b} - \Omega^{D,+}_{p,t,b} = 0, \quad \forall t, b \tag{B.28}$$
$$\omega^{G}_{p,t,x,b} - \Omega^{G,-}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.29}$$
$$\bar{G}_{x,b}\Omega^{\text{SD}}_{p} - \omega^{G}_{p,t,x,b} - \Omega^{G,+}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.30}$$
$$\omega^{W}_{p,t,x,b} - \Omega^{W,-}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.31}$$
$$\bar{W}_{t,x,b}\Omega^{\text{SD}}_{p} - \omega^{W}_{p,t,x,b} - \Omega^{W,+}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.32}$$
$$R^{D}_{x}\Omega^{\text{SD}}_{p} - \sum_{b}\left(G_{0,x,b}\Omega^{\text{SD}}_{p} - \omega^{G}_{p,1,x,b}\right) - \Omega^{R,-}_{p,1,x} = 0, \quad \forall x \tag{B.33}$$
$$R^{D}_{x}\Omega^{\text{SD}}_{p} + \sum_{b}\left(\omega^{G}_{p,t,x,b} - \omega^{G}_{p,t-1,x,b}\right) - \Omega^{R,-}_{p,t,x} = 0, \quad \forall t > 1, x \tag{B.34}$$
$$R^{U}_{x}\Omega^{\text{SD}}_{p} + \sum_{b}\left(G_{0,x,b}\Omega^{\text{SD}}_{p} - \omega^{G}_{p,1,x,b}\right) - \Omega^{R,+}_{p,1,x} = 0, \quad \forall x \tag{B.35}$$
$$R^{U}_{x}\Omega^{\text{SD}}_{p} - \sum_{b}\left(\omega^{G}_{p,t,x,b} - \omega^{G}_{p,t-1,x,b}\right) - \Omega^{R,+}_{p,t,x} = 0, \quad \forall t > 1, x \tag{B.36}$$
$$\omega^{C}_{p,t,x,b} - \Omega^{C,-}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.37}$$
$$\bar{S}^{C}_{x,b}\Omega^{\text{SD}}_{p} - \omega^{C}_{p,t,x,b} - \Omega^{C,+}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.38}$$
$$\omega^{H}_{p,t,x,b} - \Omega^{H,-}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.39}$$
$$\bar{S}^{H}_{x,b}\Omega^{\text{SD}}_{p} - \omega^{H}_{p,t,x,b} - \Omega^{H,+}_{p,t,x,b} = 0, \quad \forall t, x, b \tag{B.40}$$
$$\omega^{E}_{p,t,x} - \Omega^{E,-}_{p,t,x} = 0, \quad \forall t < T, x, b \tag{B.41}$$
$$\omega^{E,0}_{p,x} - \Omega^{E,-}_{p,T,x} = 0, \quad \forall x, b \tag{B.42}$$
$$\bar{E}_{x}\Omega^{\text{SD}}_{p} - \omega^{E}_{p,t,x} - \Omega^{E,+}_{p,t,x} = 0, \quad \forall t < T, x, b \tag{B.43}$$
$$\bar{E}_{x}\Omega^{\text{SD}}_{p} - \omega^{E,0}_{p,x} - \Omega^{E,+}_{p,T,x} = 0, \quad \forall x, b \tag{B.44}$$
(A.1), (A.8), (A.10)–(A.18), (A.26) (B.45)
$$0 \le O^{G}_{t,x,b} - O^{G}_{t,x,b-1} \perp \Phi^{G}_{p,t,x,b} \ge 0, \quad \forall y, x \in \Delta^{G}_{p}, b > 1 \tag{B.46}$$
$$0 \le O^{W}_{t,x,b} - O^{W}_{t,x,b-1} \perp \Phi^{W}_{p,t,x,b} \ge 0, \quad \forall y, x \in \Delta^{W}_{p}, b > 1 \tag{B.47}$$
$$0 \le O^{C}_{t,x,b} - O^{C}_{t,x,b-1} \perp \Phi^{C}_{p,t,x,b} \ge 0, \quad \forall y, x \in \Delta^{S}_{p}, b > 1 \tag{B.48}$$
$$0 \le O^{H}_{t,x,b} - O^{H}_{t,x,b-1} \perp \Phi^{H}_{p,t,x,b} \ge 0, \quad \forall y, x \in \Delta^{S}_{p}, b > 1 \tag{B.49}$$
$$0 \le D_{t,b} \perp \Theta^{D,-}_{p,t,b} \ge 0, \quad \forall t, b \tag{B.50}$$
$$0 \le \bar{D}_{t,b} - D_{t,b} \perp \Theta^{D,+}_{p,t,b} \ge 0, \quad \forall t, b \tag{B.51}$$
$$0 \le G_{t,x,b} \perp \Theta^{G,-}_{p,t,x,b} \ge 0, \quad \forall t, x, b \tag{B.52}$$
$$0 \le \bar{G}_{x,b} - G_{t,x,b} \perp \Theta^{G,+}_{p,t,x,b} \ge 0, \quad \forall t, x, b \tag{B.53}$$
$$0 \le \sum_{b}\left(G_{t,x,b} - G_{t-1,x,b}\right) + R^{D}_{x} \perp \Theta^{R,-}_{p,t,x} \ge 0, \quad \forall t, x \tag{B.54}$$
$$0 \le R^{U}_{x} - \sum_{b}\left(G_{t,x,b} - G_{t-1,x,b}\right) \perp \Theta^{R,+}_{p,t,x} \ge 0, \quad \forall t, x \tag{B.55}$$
$$0 \le W_{t,x,b} \perp \Theta^{W,-}_{p,t,x,b} \ge 0, \quad \forall t, x, b \tag{B.56}$$
$$0 \le \bar{W}_{t,x,b} - W_{t,x,b} \perp \Theta^{W,+}_{p,t,x,b} \ge 0, \quad \forall t, x, b \tag{B.57}$$
$$0 \le S^{C}_{t,x,b} \perp \Theta^{C,-}_{p,t,x,b} \ge 0, \quad \forall t, x, b \tag{B.58}$$

$$0 \leq \bar{S}^C_{x,b} - S^C_{t,x,b} \perp \Theta^{C,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.59}$$
$$0 \leq S^H_{t,x,b} \perp \Theta^{H,-}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.60}$$
$$0 \leq \bar{S}^H_{t,x,b} - S^H_{t,x,b} \perp \Theta^{H,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.61}$$
$$0 \leq E_{t,x} \perp \Theta^{E,-}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.62}$$
$$0 \leq \bar{E}_x - E_{t,x} \perp \Theta^{E,+}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.63}$$
$$0 \leq \theta^{D,-}_{t,b} \perp \Omega^{D,-}_{p,t,b} \geq 0, \quad \forall t, b \tag{B.64}$$
$$0 \leq \theta^{D,+}_{t,b} \perp \Omega^{D,+}_{p,t,b} \geq 0, \quad \forall t, b \tag{B.65}$$
$$0 \leq \theta^{G,-}_{t,x,b} \perp \Omega^{G,-}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.66}$$
$$0 \leq \theta^{G,+}_{t,x,b} \perp \Omega^{G,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.67}$$
$$0 \leq \theta^{R,-}_{t,x} \perp \Omega^{R,-}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.68}$$
$$0 \leq \theta^{R,+}_{t,x} \perp \Omega^{R,+}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.69}$$
$$0 \leq \theta^{W,-}_{t,x,b} \perp \Omega^{W,-}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.70}$$
$$0 \leq \theta^{W,+}_{t,x,b} \perp \Omega^{W,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.71}$$
$$0 \leq \theta^{C,-}_{t,x,b} \perp \Omega^{C,-}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.72}$$
$$0 \leq \theta^{C,+}_{t,x,b} \perp \Omega^{C,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.73}$$
$$0 \leq \theta^{H,-}_{t,x,b} \perp \Omega^{H,-}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.74}$$
$$0 \leq \theta^{H,+}_{t,x,b} \perp \Omega^{H,+}_{p,t,x,b} \geq 0, \quad \forall t, x, b \tag{B.75}$$
$$0 \leq \theta^{E,-}_{t,x} \perp \Omega^{E,-}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.76}$$
$$0 \leq \theta^{E,+}_{t,x} \perp \Omega^{E,+}_{p,t,x} \geq 0, \quad \forall t, x \tag{B.77}$$

where '$\perp$' denotes complementary slackness between an inequality constraint in firm p's MPEC and the non-negativity constraint on the corresponding Lagrange multiplier.

Conditions (B.1)–(B.44) are derived from the stationarity conditions for firm p's MPEC. These stationarity conditions involve both firm p's upper-level offer variables, as well as all primal and dual variables of the lower-level market model. Condition (B.45) is the strong-duality equality from firm p's MPEC. Conditions (B.46)–(B.77) impose the inequality constraints and complementary-slackness conditions for firm p's MPEC.

Combining conditions (B.1)–(B.77) for all of the firms yields an EPEC.

Appendix C. Objective Function of EPEC

Under relatively mild conditions, non-co-operative games, such as the one that we study, are guaranteed to have at least one Nash equilibrium. Indeed, one difficulty in game theory is that a non-co-operative game may have multiple or an infinite number of equilibria. We address this issue by using two different objective functions in the EPEC. These objective functions allow us to obtain a 'bounding range' of equilibria [32].

The first objective function:

$$\min \sum_{t,x,b} \left[C_{x,b} G_{t,x,b} - \psi_t \cdot (G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b}) \right], \tag{C.1}$$

maximizes total profits of the competing firms (keeping with the other model formulations, the objective function is written in minimization form). This objective function yields highly non-competitive equilibria, which we herein term 'collusive equilibria.' The second objective function (also written in minimization form):

$$\min \sum_{t,x,b} C_{x,b} G_{t,x,b} - \sum_{t,b} U_{t,b} D_{t,b},$$

maximizes social welfare. This objective function yields highly competitive equilibria, which we herein refer to as 'quasi-competitive equilibria.'

By using these two objective functions, we are able to examine extreme opposite cases in which the market outcome is highly competitive or non-competitive. Equilibria that occur in practice will likely lie between these two extremes. Thus, our analysis can be thought of as illustrating the worst- and best-case scenarios, from a market-efficiency perspective.

Appendix D. Linearizing the EPEC

Constraints (B.1)–(B.77) of the EPEC include a number of non-linearities, which complicate its solution. Moreover, objective function (C.1) is also non-linear in the variables of the EPEC. Thus, we take the following steps, which are outlined in this section, to linearize these non-linearities. By doing so, we obtain a tractable EPEC.

Appendix D.1. Bilinear Terms with Ω_p^{SD}

A number of bilinear terms appear in constraints (B.1)–(B.8) and (B.10)–(B.19) in which the dual variable, Ω_p^{SD}, is multiplied by a primal dispatch or offer variable. Because the variable, Ω_p^{SD}, is common in all of these terms, we parameterize the EPEC by fixing the values of Ω_p^{SD} to different quantities. We then vary the value of Ω_p^{SD} until obtaining solutions to the EPEC, which are guaranteed to be Nash equilibria (*cf.* Appendix E for details on how we verify that a EPEC solution is a Nash equilibrium). This approach to linearizing a non-linearity of this type is common practice [32–34].

Appendix D.2. Bilinear Terms in Strong-Duality Equality

Strong-duality equality (A.26), which appears in constraint (B.45) of the EPEC, has the bilinear terms, $O^G_{t,x,b} G_{t,x,b}$, $O^W_{t,x,b} W_{t,x,b}$, $O^H_{t,x,b} S^H_{t,x,b}$, and $O^C_{t,x,b} S^C_{t,x,b}$. We linearize these by noting that because the MO's problem is linear, the strong-duality equality is equivalent to the complementary-slackness conditions of the lower-level problem [32, 35]. Thus, condition (A.26) can be removed from constraint (B.45) and replaced with the following equivalent complementary-slackness conditions:

$$0 \le D_{t,b} \perp \theta^{D,-}_{t,b} \ge 0, \quad \forall t, b \tag{D.1}$$

$$0 \le \bar{D}_{t,b} - D_{t,b} \perp \theta^{D,+}_{t,b} \ge 0, \quad \forall t, b \tag{D.2}$$

$$0 \le G_{t,x,b} \perp \theta^{G,-}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.3}$$

$$0 \le \bar{G}_{x,b} - G_{t,x,b} \perp \theta^{G,+}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.4}$$

$$0 \le \sum_{b} (G_{t,x,b} - G_{t-1,x,b}) + R^D_x \perp \theta^{R,-}_{t,x} \ge 0, \quad \forall t, x \tag{D.5}$$

$$0 \le R^U_x - \sum_{b} (G_{t,x,b} - G_{t-1,x,b}) \perp \theta^{R,+}_{t,x} \ge 0, \quad \forall t, x \tag{D.6}$$

$$0 \le W_{t,x,b} \perp \theta^{W,-}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.7}$$

$$0 \le \bar{W}_{t,x,b} - W_{t,x,b} \perp \theta^{W,+}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.8}$$

$$0 \le S^C_{t,x,b} \perp \theta^{C,-}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.9}$$

$$0 \le \bar{S}^C_{x,b} - S^C_{t,x,b} \perp \theta^{C,+}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.10}$$

$$0 \le S^H_{t,x,b} \perp \theta^{H,-}_{t,x,b} \ge 0, \quad \forall t, x, b \tag{D.11}$$

$$0 \leq \bar{S}^H_{x,b} - S^H_{t,x,b} \perp \theta^{H,+}_{t,x,b} \geq 0, \quad \forall t, x, b \tag{D.12}$$

$$0 \leq E_{t,x} \perp \theta^{E,-}_{t,x} \geq 0, \quad \forall t, x \tag{D.13}$$

$$0 \leq \bar{E}_x - E_{t,x} \perp \theta^{E,+}_{t,x} \geq 0. \quad \forall t, x \tag{D.14}$$

Appendix D.3. Complementary-Slackness Conditions

Complementary-slackness conditions (B.46)–(B.77) and (D.1)–(D.14) are nonlinear because a complementarity constraint of the form:

$$0 \leq f(z) \perp \zeta \geq 0, \tag{D.15}$$

can be equivalently written as:

$$\begin{aligned} &0 \leq f(z) \\ &\zeta \geq 0 \\ &f(z)\zeta = 0. \end{aligned}$$

Complementary-slackness condition (D.15) can be linearized using the so-called Fortuny-Amat method [36]. This method introduces a binary variable (one for each complementary-slackness condition), which we denote as π, and a sufficiently large constant, which we denote as M. Condition (D.15) is then replaced with the constraints:

$$\begin{aligned} &0 \leq f(z) \leq M\pi \\ &0 \leq \zeta \leq M \cdot (1 - \pi) \\ &\pi \in \{0, 1\}. \end{aligned}$$

All of the aforementioned complementary-slackness conditions are linearized using this method.

Appendix D.4. Bilinear Terms in Objective Function (C.1)

Objective function (C.1) has the bilinear terms, $\psi_t G_{t,x,b}$, $\psi_t W_{t,x,b}$, $\psi_t S^H_{t,x,b}$, and $\psi_t S^C_{t,x,b}$. We approximate these terms using the so-called binary expansion method [37]. To do this, objective function (C.1), can be rewritten as:

$$\min \sum_{t,x,b} C_{x,b} G_{t,x,b} - \sum_t \psi_t \nu_t,$$

where the auxiliary variable, ν_t, denotes total hour-t net generation and is defined as:

$$\nu_t = \sum_{x,b} \left(G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b} \right).$$

After rewriting the objective function, we approximate ν_t as taking on one of a fixed set of values, which we denote as $\bar{\nu}_{t,1}, \ldots, \bar{\nu}_{t,\Xi}$. We assume that these values are equally spaced, meaning that $\bar{\nu}_{t,2} - \bar{\nu}_{t,1} = \cdots = \bar{\nu}_{t,\Xi} - \bar{\nu}_{t,\Xi-1} = \bar{\nu}^{\Delta}_t$. We then introduce a set of continuous and binary variables, which we denote as $\gamma_{t,1}, \ldots, \gamma_{t,\Xi}$ and $\chi_{t,1}, \ldots, \chi_{t,\Xi}$, respectively. Finally, objective function (C.1) is replaced with:

$$\min \sum_{t,x,b} C_{x,b} G_{t,x,b} - \sum_{t,\xi} \gamma_{t,\xi} \bar{\nu}_{t,\xi},$$

and the following constraints:

$$\nu_t = \sum_{x,b} \left(G_{t,x,b} + W_{t,x,b} + S^H_{t,x,b} - S^C_{t,x,b} \right), \quad \forall t$$

$$\nu_t - \bar{\nu}^{\Delta}_t \leq \sum_{\xi} \bar{\nu}_{t,\xi} \chi_{t,\xi} \leq \nu_t, \quad \forall t \tag{D.16}$$

$$\sum_{\xi} \chi_{t,\xi} = 1, \quad \forall t \tag{D.17}$$

$$0 \leq \psi_t - \gamma_{t,\xi} \leq M \cdot (1 - \chi_{t,\xi}), \quad \forall t, \xi \tag{D.18}$$

$$0 \leq \gamma_{t,\xi} \leq M \cdot \chi_{t,\xi}, \quad \forall t, \xi \tag{D.19}$$

$$\chi_{t,\xi} \in \{0, 1\}, \quad \forall t, \xi \tag{D.20}$$

are added to the EPEC.

Constraints (D.16), (D.17), and (D.20) force the variable $\chi_{t,\xi}$ that has a corresponding value of $\bar{\nu}_{t,\xi}$ that is closest to ν_t to equal 1, while the other $\chi_{t,\xi}$'s are forced equal to 0. Constraints (D.18) force the value of $\gamma_{t,\xi}$ corresponding to the $\chi_{t,\xi}$ that is equal to 1 to equal ψ_t, while constraints (D.19) force the other $\gamma_{t,\xi}$'s to equal zero. Thus:

$$\sum_{t,\xi} \gamma_{t,\xi} \bar{\nu}_{t,\xi},$$

represents the product between ψ_t and the value of $\bar{\nu}_{t,\xi}$ that is closest to ν_t.

Appendix E. Verifying Nash Equilibria

Linearizing the EPEC using the techniques that are mentioned in Appendix D yields an MILP. As noted before, a solution to this MILP is a solution to the original EPEC. However, there is no guarantee that an EPEC solution is a Nash equilibrium [32, 33]. Thus, we verify whether an EPEC solution is in fact a Nash equilibrium by using diagonalization [33, 34]. Diagonalization involves solving each firm's MPEC, while holding the decision variables of all of that firm's rivals fixed equal to the values that are obtained from the EPEC solution. If the EPEC solution is optimal in each firm's MPEC, that means the EPEC solution satisfies the no-unilateral-deviation property and is indeed a Nash equilibrium. Otherwise, if the EPEC solution is not optimal in the MPEC of one or more firms, the EPEC solution does not constitute a Nash equilibrium and is discarded from further consideration.

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