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Analysis of imperfect competition in natural gas supply contracts for electric power generation: A closed-loop approach

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ABSTRACT

The supply of natural gas is generally based on contracts that are signed prior to the use of this fuel for power generation. Scarcity of natural gas in systems where a share of electricity demand is supplied with gas turbines does not necessarily imply demand rationing, because most gas turbines can still operate with diesel when natural gas is not available. However, scarcity conditions can lead to electricity price spikes, with welfare effects for consumers and generation firms. We develop a closed-loop equilibrium model to evaluate if generation firms have incentives to contract or import the socially-optimal volumes of natural gas to generate electricity. We consider a perfectly-competitive electricity market, where all firms act as price-takers in the short term, but assume that only a small number of firms own gas turbines and procure natural gas from, for instance, foreign suppliers in liquefied form. We illustrate an application of our model using a network reduction of the electric power system in Chile, considering two strategic firms that make annual decisions about natural gas imports in discrete quantities. We also assume that strategic firms compete in the electricity market with a set of competitive firms do not make strategic decisions about natural gas imports (i.e., a competitive fringe). Our results indicate that strategic firms could have incentives to sign natural gas contracts for volumes that are much lower than the socially-optimal ones, which leads to supernormal profits for these firms in the electricity market. Yet, this effect is rather sensitive to the price of natural gas. A high price of natural gas eliminates the incentives of generation firms to exercise market power through natural gas contracts.

1. Introduction

Natural gas has become an important resource for electricity generation. Since the 1980s, the share of electricity produced worldwide using natural gas has increased from 8% to nearly 23% in 2015 (EIA, 2019a). This increase in the use of natural gas for electricity production is a consequence of aggressive extraction efforts in the U.S., Asia & Oceania, the Middle East, and Africa (Moniz et al., 2011) and a reduction in the Henry Hub natural gas spot price from 14.2 $/MMBtu in 2005 to a low of 2.6 $/MMBtu in 2016 (EIA, 2019b). While the increasing levels of penetration of renewable energy resources and storage are expected to reduce our reliance on fossil fuels, the International Energy Agency predicts that the use of natural gas for electricity generation will keep increasing up to 2027 in a Sustainable Development Scenario, in line with the Sustainable Development Goals set by the United Nations (EIA, 2019a).

Gas turbines are valuable assets in systems with large shares of generation from wind and solar resources. Unlike coal units, gas turbines can provide flexibile supply of power that can be used to balance the variability and unpredictability of wind and solar resources (Moniz et al., 2011; Lee et al., 2012). They can also provide these services at lower costs and with lower emissions levels than diesel units. Yet, the availability of natural gas is not uniform around the globe and many countries, states, or generation firms must rely on cross-border trading and the development of costly infrastructure to secure the availability of this fuel for the production of electricity.

Gas pipelines are a common alternative for the transportation of natural gas from suppliers to generation firms in all continents. For longer distances, when it cannot be delivered on land, natural gas is often transported in liquefied form (LNG), which requires gas liquefaction plants, gas tankers, and LNG terminals, in addition to gas pipelines. Given the high overhead costs of developing such infrastructure and the price volatility of natural gas in international markets, it is common for generation firms or midstreamers to secure the supply of this fuel through contracts for prices and volumes that are determined prior to

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its use for electricity generation (Abada et al., 2017). In some cases, these contracts can include take-or-pay clauses or indexation parameters that give suppliers additional alternatives to manage risk (Masten and Crocker, 1985).

A salient feature of gas generation is that changes in the availability or price of natural gas can have large effects on electricity prices. For example, beginning in 2004, Chile experienced a long period of scarcity of natural gas for electricity generation due to a political and an economic crisis in Argentina, its main supplier of this fuel. The gas shortage did not result in demand rationing of electricity because gas units were still able to operate with diesel (Raineri, 2006). However, electricity prices increased from an average of 25 $/MWh, prior to the period of natural gas restrictions, to more than 300 $/MWh in the fall of 2008 (Systep, 2019). Cold winters and a high demand of natural gas for heating can also limit the availability of this fuel for power generation. For instance, in the electricity market of New England in North America, the average electricity price during the unusually cold winter of 2013/2014 was 137.6 $/MWh, whereas the average electricity price in the same season of 2015/2016, with milder temperatures, was just 27.6 $/MWh (ISONE, 2019). The price spike during the winter of 2013/2014 occurred due to constraints in gas pipelines or delayed LNG deliveries, leading to high natural gas prices in local markets. Periods of scarcity of natural gas have also been a concern in the electricity markets of California, the Midcontinent ISO, PJM, and the New York ISO (Walton, 2016).

Under ideal conditions, electricity price spikes provide efficient signals for investments and give incentives to consumers exposed to spot prices to reduce demand (Cramton, 2017). However, price signals become distorted and result in welfare losses if scarcity conditions are the result of strategic behavior by generation firms (Wilson, 2000; Munoz et al., 2018).

Motivated by the strong linkage between the availability of natural gas and electricity prices, we propose an equilibrium model to evaluate if generation firms have incentives to procure the socially-optimal levels of natural gas for power generation. We develop a closed-loop equilibrium model considering transmission constraints and linear losses, as well as demand, wind, solar, and hydro variability. In this model we assume that all generation firms behave competitively in the electricity spot market. However, firms that import natural gas can make strategic decisions about import volumes, taking into account the effects of these decisions upon electricity prices and dispatch decisions. We formulate this model as an Equilibrium Problem with Equilibrium Constraints (EPEC) that we solve by a discretization of the strategy space of strategic firms. This solution approach allows us to identify all possible Nash equilibria of the game and develop a better understanding the firms' best response functions than what would be possible using a complementarity-based approach. We also develop a planning model that identifies the socially-optimal levels of natural gas imports for all firms and that we employ as a benchmark in our analysis.

We illustrate an application of the proposed model using a 9-node network reduction of the main electric power system in Chile, considering two strategic firms that make commitments of natural gas import volumes prior to the operation of the electricity market. Our results indicate that firms have incentives to exercise market power by making natural gas more scarce than under the socially-optimal import volumes. While the scarcity of natural gas does not result in electricity demand curtailment, it raises electricity prices, which is captured by strategic firms through a portfolio of inframarginal units. We also find that, for the set of scenarios considered in our study, the incentives to exercise market power by strategic firms are more sensitive to the price of natural gas in international markets than to the availability of hydro resources for electricity generation. Furthermore, we study the effect of different natural gas contract types—flexible or inflexible—that firms can report to the System Operator (SO). We find that the contract type has a negligible influence on the type of Nash equilibria we identify for each scenario of hydro conditions and natural gas prices.

The rest of the paper is structured as follows. In Section 2 we review the existing literature on the different approaches to model strategic behavior in electricity and natural gas markets and on the interdependencies of infrastructure between these two areas. In Section 3 we present our methodology, describing the models employed in our analysis and the solution approach. In Section 4 we present a case study of the electric power system in Chile and our data assumptions to illustrate an application of the equilibrium models. In Section 5 we present our results considering different scenarios of system conditions. Finally, in Section 6 we conclude.

2. Literature review

There is a broad array of models to study incentives for the exercise of market power in electricity markets (Ventosa et al., 2005). Strategic bidding in wholesale spot markets is often modeled using Nash-Cournot models of imperfect competition (Jing-Yuan and Smeers, 1999; Hobbs, 2001), which assume that firms compete in quantities. More elaborate models of supply function equilibria better represent the bidding mechanism than the Cournot assumption (Baldick et al., 2004), but they are much more difficult to solve if realistic features such as transmission constraints are considered (Holmberg, 2009). In two-settlements electricity markets (e.g., day-ahead and real-time markets), strategic behavior can be modeled using closed-loop equilibrium models of imperfect competition (Yao et al., 2008).

A common assumption in all the previous examples is that capacity decisions are exogenous. However, one would expect that if firms could exercise market power and raise prices in the short term, there would be incentives for investment in new generation capacity if there are no barriers to entry. Kreps and Scheinkman (1983) used a simple duopoly model to show that if firms first make quantity or capacity commitments with zero cost and later compete in prices, the unique equilibrium of the game is the Cournot outcome. Murphy and Smeers (2005) perform a much more detailed analysis than the one in Kreps and Scheinkman (1983), with a focus on investments in generation capacity in electricity markets under varying demand conditions. The authors consider two firms, one that can invest in a peaking technology and another one that can invest in baseload generation. In the closed-loop case they find that best response functions have both decreasing and flat segments, combined with jumps or discontinuities. In addition, Murphy and Smeers (2005) find that the equilibrium solution of the closed-loop model, when it exists, it is unique and results in prices and quantities that lie between the results of the open-loop game (Cournot) and the competitive equilibrium. Consequently, the findings of Kreps and Scheinkman (1983) do not longer hold when considering multiple demand periods and asymmetric firms in a duopoly with costly investment.

Of course, strategic bidding in wholesale spot markets is not the only manner in which generation firms can exercise market power. Wogrin et al. (2013b) and Munoz et al. (2018) used closed-loop equilibrium models applied to investment problems in electricity markets to show that if in a concentrated market firms are aware that they will subject to very strict market power mitigation measures or to a cost-based market, they could still behave strategically by selecting investments in specific types, sizes, and locations of generation units that would result in higher profits than under price-taking behavior.

Generation firms can also exercise market power by untruthfully reporting unit parameters such as ramping limits or minimum generation levels, or by taking advantage of these constraints in sequential markets. This issue was first studied by Kai et al. (2000) and later extended by Oren and Ross (2005); Moiseeva et al. (2015) and Moiseeva et al. (2017) using more sophisticated models, such as conjectural variations and closed-loop equilibrium problems. There is also empirical evidence that generation firms have incentives to engage in such practices. In 2013, the firm J.P. Morgan was fined $410 M for strategic bidding in day-ahead and real-time markets, taking advantage of the Make Whole Payment mechanism through binding ramping limits in the electricity market of California (FERC, 2013). Interestingly, such strategic behavior is not limited to bid-based electricity markets, which are common in the U.S. and in Europe. The electricity market in Chile relies on a cost-based mechanism for the dispatch and pricing of generating units in the short term, which means that firms are not allowed to submit bids. Nevertheless, there have been two recent cases of generation firms being fined for untruthfully reporting minimum generation levels and up times that led to supernormal profits, an increase in operating costs and prices, and the spillage of solar resources (REI, 2016, 2018).[1]

In practice, most generation firms have contractual obligations or vertical arrangements that might reduce their incentives to exercise market power. The basic intuition for this result comes from the work of Allaz and Vila (1993). The authors employ a simple model of Cournot competition with forward trading to show that financial contracts can steer the resulting equilibrium towards the perfectly-competitive outcome. Bushnell et al. (2008) provides some empirical evidence of this result, noting that equilibrium prices in some electricity markets in the U.S. are similar to the values predicted using Cournot model that take into account contractual agreements. However, it has been shown that forward contracts do not necessarily reduce market power when capacity decisions are endogenous (Murphy and Smeers, 2010).

There are also models of imperfect competition applied to natural gas markets. Gabriel et al. (2005a) and Gabriel et al. (2005b), for instance, develop mixed-complementarity problems of Nash-Cournot competition in natural gas markets, considering producers, storage and peak gas operators, third-party marketers and end-use operators. Holz et al. (2008) applies similar models of Nash-Cournot competition to European gas markets considering multiple market settings (e.g., Cournot competition in upstream markets, downstream markets, or in both). Abada et al. (2017) develops a more elaborate equilibrium model considering uncertainty, risk-averse agents, and endogenous natural gas contracts, but assuming price-taking agents. In Valle et al. (2019) the authors develop a multi-objective bi-level optimization problem for the analysis of investment in new gas infrastructure in Western Europe. In the upper-level problem the European Commission acts as a network planner, optimizing investment decisions. The lower-level problem is a generalized Nash-Cournot equilibrium that represents the downstream natural gas market with fixed investments.

Nevertheless, we are only aware of one previous article studying the effects of strategic natural gas procurement decisions on the electricity market, as we do in this paper. Duenas et al. (2012) propose an equilibrium model that considers both multi-year natural gas contracts and participation in the electricity market, assuming that generation firms take into account the impact of their production decisions using a model of conjectural variations. We improve upon the model proposed by Duenas et al. (2012) by developing a closed-loop model of imperfect competition instead of one of conjectural variations and by considering transmission constraints. As it has been documented, equilibrium outcomes can be very sensitive to the choice of conjectural variation, which might be also inconsistent with the actual ability of a firm to affect prices in equilibrium (Lindh, 1992; Díaz et al., 2010). The rest of the existing literature that addresses the interdependencies between natural gas infrastructure and electric power systems focuses mostly on the economic benefits of co-optimized decisions of natural gas infrastructure and electric power systems (Shahidehpour et al., 2005; Li et al., 2008; Chaudry et al., 2014; Toledo et al., 2016; Saldarriaga-Cortés et al., 2019), disregarding strategic behavior.

3. Methodology

In this section, we describe a closed-loop equilibrium model of imperfect competition and a planning model that is equivalent to an equilibrium model where all firms act as price takers. We use the closed-loop model to study the incentives of strategic firms to exercise market power in the electricity market by selecting natural gas contract volumes that differ from the socially-optimal levels. In Section 3.1 we first describe the closed-loop equilibrium model formulated as an EPEC, where strategic generation firms select natural gas contract volumes taking into account the effect of these decisions in the optimal dispatch decisions and electricity prices determined by the SO. In Section 3.2 we describe a planning model that provides the socially-optimal outcomes.

For simplicity, we make two important assumptions. First, we assume that the electricity market is perfectly competitive and focus only on strategic behavior in natural gas supply contracts for power generation. In bid-based electricity markets, such as many of the deregulated markets in North America, Europe, Australia, and New Zealand, this assumption implies that all firms submit bids that reflect their true marginal costs and that do not withhold generation capacity. In cost-based markets, such as the ones in Chile, Bolivia, Peru and countries in Central America, perfect competition means that the SO has access to all the relevant information needed to determine the true marginal cost of generation of all units in the system, including all relevant opportunity costs.

Second, we assume that the price of natural gas in international markets, denoted GP, is exogenous, ignoring the effect of the demand for natural gas of generation firms in Chile on international natural gas prices. Consequently, GP in our model is just a parameter for which we analyze different scenarios of natural gas prices.

These are, of course, convenient assumptions that simplify our models. In practice, generators might have incentives to exercise market power in bid-based markets with few dominant firms and weak transmission systems (Borenstein et al., 1999). Furthermore, in cost-based markets the SO might not be able to compute all relevant opportunity costs for generators, which could yield inefficient dispatch schedules and prices (Munoz et al., 2018). Nonetheless, the models proposed here can be extended directly using, for instance, the assumption of Cournot competition among firms in the electricity market.

Natural gas prices can be also represented as endogenous variables in the model by explicit consideration of supply and demand conditions for this fuel in international markets. This could be done using, for example, variants of the models proposed by Smeers (1997), Gabriel et al. (2005a), Gabriel et al. (2005b), or Abada et al. (2017). However, modeling imperfect competition in the electricity market or endogenous price formation in natural gas markets is beyond the scope of this paper and we leave it as subject for future research.

Nomenclature

Set definitions

$\mathcal{B}$	Buses or nodes, indexed b
$\mathcal{J}$	Generation firms, indexed j
$\mathcal{G}$	Generation units in the system, indexed i
$\mathcal{G}(j)$	Subset of generation units owned by firm j
$\mathcal{G}(b)$	Subset of generation units at bus b
$\mathcal{L}$	Transmission lines, indexed l
$\mathcal{T}$	Operating periods, indexed t

Parameters

CF_i	Maximum annual capacity factor
D_{bt}	Demand level [MW]
F_l	Line thermal limit [MW]
FOR_i	Forced outage rate
G_{ij}	Generator-firm incidence matrix

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[1] As discussed in Munoz et al. (2018), cost-based electricity market designs do not necessarily prevent firms from exercising market power due to information asymmetries between the SO (or regulator) and generation firms and the difficulty of performing periodic audits to validate reported parameter values for all generation units in a system.

GP	Price of natural gas [\$/MMBtu]
H_t	Length of time period [hrs]
HR_i	Generator heat rate [MMBtu/MWh]
IM_{lb}	Line-bus incidence matrix
K_i	Generation capacity [MW]
MC_i	Marginal cost of generation [\$/MWh]
$LOSS_l$	Transmission loss
S_l	Line susceptance [p.u.]
$VOLL$	Value of lost load [\$/MWh]
W_{it}	Availability factor of generation technology

Decision variables

f_{lt}^+, f_{lt}^-	Power flows [MW]
q_{it}	Dispatch level [MW]
θ_{bt}	Phase angle
u_{bt}	Demand curtailment [MW]
x_j	Volume of natural gas contracted for the year [m^3]

3.1. Closed-loop equilibrium model

3.1.1. Lower-level problem

In the lower-level problem we assume that generation firms act as price takers with respect to the locational marginal prices computed by the SO, taking the contracted volumes of natural gas as x_j as parameters. With inelastic demand, it is possible to compute a solution of the resulting equilibrium problem by solving an equivalent optimization program, where the SO minimizes annual operating costs by selecting dispatch schedules, load curtailment levels, and line flows (Samuelson, 1952; Munoz et al., 2017).

The following linear program describes the optimization problem solved by the SO in the lower level:

$$\min \sum_{t\in\mathcal{T}} H_t \cdot \left[\sum_{i\in\mathcal{G}} MC_i \cdot q_{it} + \sum_{b\in\mathcal{B}} VOLL \cdot u_{bt}\right] \tag{1}$$

Subject to:

$$D_{bt} - \sum_{i\in\mathcal{G}(b)} q_{it} - u_{bt} - \sum_{l\in\mathcal{L}} IM_{lb} \cdot \left[LF_{lb}^+ \cdot f_{lt}^+ - LF_{lb}^- \cdot f_{lt}^-\right] = 0 \quad (p_{bt}) \quad \forall b\in\mathcal{B}, t\in\mathcal{T} \tag{2}$$

$$f_{lt}^+ - f_{lt}^- - S_l \cdot \sum_{b\in\mathcal{B}} IM_{lb} \cdot \theta_{bt} = 0 \quad (\nu_{lt}) \quad \forall l\in\mathcal{L}, t\in\mathcal{T} \tag{3}$$

$$f_{lt}^+ - F_l \le 0 \quad (\mu_{lt}^+) \quad \forall l\in\mathcal{L}, t\in\mathcal{T} \tag{4}$$

$$f_{lt}^- - F_l \le 0 \quad (\mu_{lt}^-) \quad \forall l\in\mathcal{L}, t\in\mathcal{T} \tag{5}$$

$$q_{it} - K_i \cdot W_{it} \cdot (1 - FOR_i) \le 0 \quad (\lambda_{it}) \quad \forall i\in\mathcal{G}, t\in\mathcal{T} \tag{6}$$

$$\sum_{t\in\mathcal{T}} H_t \cdot q_{it} - CF_i \cdot K_i \sum_{t\in\mathcal{T}} H_t \le 0 \quad (\beta_i) \quad \forall i\in\mathcal{G} \tag{7}$$

$$\sum_{t\in\mathcal{T}} \sum_{i\in\mathcal{G}} H_t \cdot HR_{it} \cdot G_{ij} \cdot q_{it} - x_j \le 0 \quad \left(\eta_j\right) \quad \forall j\in\mathcal{J} \tag{8}$$

$$q_{it} + q_{e(i)t} - K_i \cdot W_{it} \cdot (1 - FOR_i) \le 0 \quad (\psi_{it}) \quad \forall i\in\mathcal{G}_G, t\in\mathcal{T} \tag{9}$$

$$f_{lt}^+, f_{lt}^- \ge 0 \qquad \forall l\in\mathcal{L}, t\in\mathcal{T} \tag{10}$$

$$q_{it} \ge 0 \qquad \forall i\in\mathcal{G}, t\in\mathcal{T} \tag{11}$$

$$u_{bt} \ge 0 \qquad \forall b\in\mathcal{B}, t\in\mathcal{T} \tag{12}$$

The parameters LF_{lb}^+ and LF_{lb}^- are defined as follows:

$$LF_{lb}^+ = 1 - \frac{LOSS_l}{2}(1 + IM_{lb}) \tag{13}$$

$$LF_{lb}^- = 1 - \frac{LOSS_l}{2}(1 - IM_{lb}) \tag{14}$$

Constraint (2) balances supply and demand at every node in every time period, considering line inflows/outflows and transmission losses. Note that if $IM_{lb}=1$, then $LF_{lb}^+=1 - LOSS_l$ and $LF_{lb}^-=1$, which implies that if $f_{lt}^+>0$ (i.e., there is power flowing into node b) there is a loss equal to $LOSS_l \cdot f_{lt}^+$. However, if $f_{lt}^->0$ (i.e., there is power flowing out of node b), then the line loss is accounted for at the node in the other end of the transmission line. Constraints (4) and (5) impose maximum flow limits on transmission lines. Following the formulation of power flows used in Munoz et al. (2013) and in Özdemir et al. (2015), constraint (3) imposes Kirchhoff's Voltage Law in meshed transmission systems. This formulation requires selecting a reference node b^* where $\theta_{b^*t}=0 \ \forall t\in\mathcal{T}$.

In (6) we impose maximum generation limits per generator derated by average forced outage rates. We model wind and solar variability using hourly capacity factors W_{it} from historical data, for all other generation technologies $W_{it}=1$. Constraint (7) imposes maximum annual capacity factors, which we use to constrain generation from hydro units.[2] For those units, the Lagrange multiplier β_i is the value of an additional unit of water for electricity generation. Constraint (8) limits the amount of electricity that gas turbines can produce over the year taking as an input the contracted volumes of natural gas per firm x_j. For simplicity, here we ignore natural gas storage and transport constraints and assume that total volume of natural gas contracted per firm x_j can be used to power any of the gas turbines owned by firm j. However, natural gas storage and transport constraints can be accounted for extending our model with features from Toledo et al. (2016). In constraint (9) we limit the amount of power that a gas turbine i and its virtual diesel counterpart $e(i)$ can produce in a time period. This constraint can only be active if the SO finds that it is optimal to run the turbine with natural gas for some fraction of the time period t and with diesel for the remaining fraction of t.[3] In practice, we observe that this constraint never binds and $\psi_{it}=0 \ \forall i\in\mathcal{G}_G, t\in\mathcal{T}$.

The KKT conditions of the optimization problem solved by the SO are the following ones:

$$0 \le q_{it} \perp -H_t \cdot MC_i + p_{b(i)t} - \lambda_{it} - H_t \cdot \beta_i - \tag{15}$$

$$H_t \cdot HR_i \cdot G_{ij} \cdot \eta_j - \psi_{it} \le 0 \qquad \forall i\in\mathcal{G}, t\in\mathcal{T} \tag{16}$$

$$0 \le u_{bt} \perp -H_t \cdot VOLL + p_{bt} \le 0 \qquad \forall b\in\mathcal{B}, t\in\mathcal{T} \tag{17}$$

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[2] We want to highlight that modeling hydro units with storage capabilities using maximum annual capacity factors is only an approximation. A much more accurate formulation would include energy balance constraints, as well as discharge and spillage variables per period, or even nonlinear-head effects (Ramírez-Sagner and Muñoz, 2019). Furthermore, if energy storage technologies become important in the future, much more detailed formulations will be required, such as the ones used in Wogrin and Gayme (2014) and Go et al. (2016). Note that consideration of storage units does not necessarily require using hourly chronological data. Wogrin et al. (2015) and Tejada-Arango et al. (2017) show that it is possible to recover some of the chronological information needed to model energy storage technology by using only a subset of representative system states, akin to load-duration curves.

[3] A more sophisticated approach could be to introduce binary variables s_{it} that indicate whether a gas turbine is operating with gas ($s_{it}=1$) or not ($s_{it}=0$) in a given period t. We could then replace constraint (9) by $q_{it} \le M \cdot s_{it}$ and $q_{e(i)t} \le M \cdot (1 - s_{it})$, where M is a large positive number. Unfortunately, such formulation would make the lower-level equilibrium problem nonconvex and the locational marginal prices p_{bt} that result from fixing the binary variables s_{it} to their optimal values would not necessarily support the optimal dispatch decisions of the SO (e.g., some generation units might operate at a loss) (O'Neill et al., 2005).

$$0 \leq f^+_{lt} \perp \sum_{b \in \mathcal{B}} IM_{lb} \cdot LF^+_{lb} \cdot p_{bt} - \mu^+_{lt} - \nu_{lt} \leq 0 \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{18}$$

$$0 \leq f^-_{lt} \perp \sum_{b \in \mathcal{B}} IM_{lb} \cdot LF^-_{lb} \cdot p_{bt} - \mu^-_{lt} + \nu_{lt} \leq 0 \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{19}$$

$$p_{bt} \text{ free} \perp D_{bt} - \sum_{i \in \mathcal{G}(b)} q_{it} - u_{bt} - \sum_{l \in \mathcal{L}} IM_{lb} \cdot \left[LF^+_{lb} \cdot f^+_{lt} - LF^-_{lb} \cdot f^-_{lt}\right] = 0 \quad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{20}$$

$$\nu_{lt} \text{ free} \perp f^+_{lt} - f^-_{lt} - S_l \cdot \sum_{b \in \mathcal{B}} IM_{lb} \cdot \theta_{bt} = 0 \quad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{21}$$

$$0 \leq \mu^+_{lt} \perp f^+_{lt} - F_l \leq 0 \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{22}$$

$$0 \leq \mu^-_{lt} \perp f^-_{lt} - F_l \leq 0 \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{23}$$

$$0 \leq \lambda_{it} \perp q_{it} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \quad \forall i \in \mathcal{G}, t \in \mathcal{T} \tag{24}$$

$$0 \leq \beta_i \perp \sum_{t \in \mathcal{T}} H_t \cdot q_{it} - CF_i \cdot K_i \sum_{t \in \mathcal{T}} H_t \leq 0 \quad \forall i \in \mathcal{G} \tag{25}$$

$$0 \leq \eta_j \perp \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{G}} H_t \cdot HR_{it} \cdot G_{ij} \cdot q_{it} - x_j \leq 0 \quad \forall i \in \mathcal{J} \tag{26}$$

$$0 \leq \psi_{it} \perp q_{it} + q_{e(i)t} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \quad \forall i \in \mathcal{G}_G, t \in \mathcal{T} \tag{27}$$

3.1.2. Upper level equilibrium

We assume that there is a subset of strategic firms $\mathcal{J}_S$ that own natural gas turbines that contract a fixed amount of natural gas for the year x_j for a price GP, taking into account the effect of these decisions on electricity prices p_{bt} and dispatch decisions q_{it}. Abusing notation, we denote x_{-j} the contract decisions of rival firms. Electricity prices and dispatch decisions can be now expressed as $p_{bt}(x_j, x_{-j})$ and $q_{it}(x_j, x_{-j})$, respectively. Given a set of natural gas contracts for all strategic firms (x_j, x_{-j}), the annual profits from electricity sales for firm $j \in \mathcal{J}_S$ can be expressed as follows:

$$\Pi_j(x_j, x_{-j}) = \sum_{t \in \mathcal{T}} H_t \sum_{i \in \mathcal{G}} G_{ij} \cdot \left[p_{b(i)t}(x_j, x_{-j}) - MC_i\right] \cdot q_{it}(x_j, x_{-j}) - GP \cdot x_j \tag{28}$$

We assume that each strategic firm $j \in \mathcal{J}_S$ is rational and selects a contract level x_j taking the rival's decisions x_{-j} as fixed quantities. We express the profit-maximization problem of each strategic firm as follows:

$$\max_{x_j} \ \Pi_j(x_j, x_{-j}) \tag{29}$$

Subject to:

$$x_j \geq 0 \tag{30}$$

Constraints (15) to (27)

Since constraints (15) to (27) are complementarity conditions, each strategic firm $j \in \mathcal{J}_S$ solves an optimization problem subject to the KKT conditions of the lower-level problem, also known as a Mathematical Problem with Equilibrium Constraints (MPEC). The set of all MPECs for all strategic firms $\mathcal{J}_S$ defines an Equilibrium Problem with Equilibrium Constraints (EPEC).

3.2. A planning model of natural gas imports

We also formulate a planning model to find the socially-optimal solution of the planning problem, assuming that a central authority could make such decision under perfect information. This planning model finds the import volumes of natural gas for strategic firms that minimize the total system cost (i.e., cost of supplying electricity plus the cost of natural gas imports).

The optimization problem of the central planner is formulated as follows:

$$\min_{q,u,x} \sum_{t \in \mathcal{T}} H_t \cdot \left[\sum_{i \in \mathcal{G}} MC_i \cdot q_{it} + \sum_{b \in \mathcal{B}} VOLL \cdot u_{bt}\right] + \sum_{j \in \mathcal{J}_S} GP \cdot x_j \tag{31}$$

Subject to:

Constraints (2)–(12), (30)

Note that if import levels x_j are continuous, the optimization problem of the central planner coincides with the solution of a closed-loop equilibrium problem, where firms select natural gas import decisions at the same time they choose production levels in the electricity market (Samuelson, 1952; Munoz et al., 2017). However, if x_j are discrete variables, as we assume in our solution approach, this equivalency does not necessarily hold.

3.3. Solution approach

EPECs are not guaranteed to have a pure-strategy Nash equilibrium and, if one exists, it might not be unique due to nondifferentiability and nonquasi-concavity issues that are common in applications with transmission constraints (Ehrenmann, 2004). Therefore, identifying even one Nash equilibrium (if one exists) can be extremely challenging.

A common approach to identify stationary points of complex or large-scale games is through diagonalization (Ahn and Hogan, 1982). This process is akin to a Gauss-Seidel fixed-point iteration, where each player $j \in \mathcal{J}_S$ solves the MPEC problem described in the previous section, assuming that all of the other agents' strategies x_{-j} are fixed. The algorithm converges when no agent $j \in \mathcal{J}_S$ changes its strategy x_j from the previous iteration. Some examples of the application of this method to find stationary points of EPECs in electricity markets include Cardell et al. (1997), Hobbs et al. (2000), Su (2005), Hu and Ralph (2007), Yao et al. (2008), and Wogrin et al. (2013a). In general, convergence of the diagonalization method in these settings is not guaranteed and can be sensitive to choice of the point used to initiate iterations. Furthermore, in the presence of multiple Nash equilibria, the algorithm (if it converges) will return only one Nash equilibrium for each starting point, making it hard to draw general conclusions about the problem. One strategy to identify multiple equilibria, if they exist, is using multiple starting points.

Another solution alternative is the identification of Nash equilibria through the intersection of best-response functions (BRFs). Murphy and Smeers (2005), for instance, derive closed-form solutions of BRFs for a closed-loop investment game between a peaking generator and a base-plant unit, which allows them to characterize all possible Nash equilibria and provide general results. Wogrin et al. (2013b) follow a similar approach to compare the solutions of open- and closed-loop equilibrium models. However, closed-form solutions to BRFs for all agents in equilibrium models with more realistic features, including intertemporal constraints (e.g., maximum generation per year) and transmission limits, may simply not exist.

Here we employ a simple solution approach based on an approximation to the original equilibrium problem described previously. We assume that natural gas contract volumes x_j can only be made in discrete amounts (e.g., a multiple or a fraction of the volume of gas that can be stored in one tank of an LNG carrier). This simplification allows us to compute BRFs for all strategic firms and then identify all possible Nash equilibria of the game. We compute solutions as follows:

1. First, we compute the maximum volume of natural gas that each generation firm could use over the set periods $\mathcal{T}$, denoted X_j^{Max}. We compute this bound by simply assuming that all gas units owned by firm j can operate at nominal capacity over all periods $t\in\mathcal{T}$. Under perfect information, we know that rational firms will always choose import levels x_j such that $0 \le x_j \le X_j^{Max}$.
2. Second, we focus on possible contract strategies x_j such that $x_j \in [0, X_j^{Max}]$ $\forall j\in\mathcal{J}_S$ and discretize the solution spaces $[0, X_j^{Max}]$ taking as a reference, for instance, the volume of gas that can be stored in one tank of an LNG carrier.
3. Third, we solve the lower-level problem (i.e., economic dispatch) for each possible combination of contract volumes of strategic firms. This provides the optimal dispatch decisions $q_{it}(x_j, x_{-j})$ and locational marginal prices $p_{b(i)t}(x_j, x_{-j})$ needed to compute the profit function $\Pi_j(x_j, x_{-j})$ of each strategic firm $j\in\mathcal{J}_S$.
4. Fourth, we compute the BRF of each firm $j\in\mathcal{J}_S$, here denoted $F_j(x_{-j})$, by solving the following problem:

$$F_j(x_{-j}) = \text{argmax}\ \Pi_j(x_j, x_{-j})$$

5. Finally, we identify all Nash equilibria.

Note that the solution of the planning problem can be computed directly from this discretization, but it is also possible to find it by solving a mixed-integer linear program.

The solution strategy described here is practical for the main purpose of our work, which is an economic analysis of imperfect competition in natural gas contracts for electric power generation. However, computational tractability might be an issue for large systems with many different generation firms that import natural gas.

An alternative that seems promising is to explicitly write the set of constraints that define a Nash equilibrium in the upper-level game (natural gas imports) together with the set of first-order conditions that define a competitive equilibrium in the lower-level game (electricity market). This requires linearization of the first-order conditions of the lower-level game by introducing new binary variables and disjunctive constraints (Fortuny-Amat and McCarl, 1981). Since import levels are discrete, the upper-level game can be replaced by the set of Nash-equilibrium conditions for each player, subject to the linearized first-order conditions from the lower-level game and all physical constraints. A solution to this set of linear inequalities provides one Nash equilibrium of the game. Moreover, it is possible to define an objective function to select one specific equilibrium point by, for instance, maximizing or minimizing total system cost subject to equilibrium conditions. Variants of this solution approach have been used in other applications, such as strategic investment in generation capacity (Wogrin et al., 2012) and proactive transmission planning subject to generation investments and operations (Pozo et al., 2012, 2017). For large-scale problems it is also possible to apply these techniques using customized decomposition algorithms (Pozo et al., 2017) or iterative variants that are capable of finding all possible Nash equilibria (Pozo and Contreras, 2011). Implementation of these solution algorithms is beyond the scope of this work.

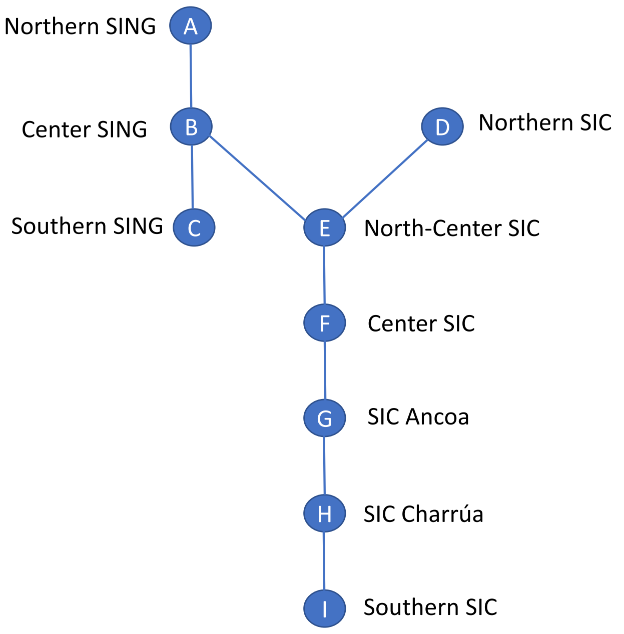

Fig. 1. 9-Node network representation of the main transmission system in Chile.

Table 1
Installed generation capacity for the two strategic firms and the competitive fringe in MW.

Technology	Firm 1	Firm 2	Fringe	Total
Biogas	–	–	59.7	59.7
Biomass	–	–	425.9	425.9
Coal	370.0	661.8	4622.5	5654.3
Diesel	314.7	338.8	2259.4	2912.9
Gas turbine (dual)	1769.5	1644.8	1328.8	4743.1
Large hydro	741.0	1678.0	1037.0	3456.0
Mini hydro	26.8	30.0	396.3	453.0
Petcoke	–	–	75.0	75.0
Propane	–	–	14.5	14.5
RoR hydro	797.8	314.8	1391.2	2503.8
Solar	–	–	1704.6	1704.6
Wind	–	18.2	1302.5	1320.7
Total general	4019.8	4686.3	14,617.3	23,323.4

4. Case study

We show an application of the model described in the previous section employing a 9-node network reduction of the main electric power system in Chile from Moreno et al. (2015), depicted in Fig. 1. Table A.8 in Appendix shows line ratings for the 8 transmission corridors considered in our study. We consider a loss factor of 6% of power flows, which is equal to average transmission losses reported by the National Independent System Operator (CEN, 2018).

We assume that the two largest generation firms in the country, here denoted Firm 1 and Firm 2,[4] make decisions on natural gas imports strategically, anticipating the effect of their decisions on dispatch levels and electricity prices. These two firms own a diverse portfolio of generation technologies that can, in principle, help them capture the benefits of reducing the availability of natural gas in the system through other generation units with low operating costs, such as hydropower.

We group all other generation firms into a single competitive fringe that has a fixed level of natural gas available for the year in study based on historical data. Table 1 shows installed capacity per technology for the two strategic firms and the fringe. We want to highlight that the 1328.8 MW of gas generation capacity included in the fringe belong to small firms that, unlike Firm 1 and Firm 2, own little or no generation units that operate with fuels other than natural gas. Since, in practice, a large fraction of the natural gas utilized by fringe firms is purchased in local, secondary markets, our assumption to include these firms as part of a perfectly competitive fringe should not alter our results significantly.

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[4] In this article we only use the electric power system in Chile as an application of our model, therefore, we prefer to omit actual firm names in order to avoid a potential misinterpretation of our results.

We employ a data set of nine hourly demand profiles (one per node), four profiles of wind generation, and two solar profiles for year 2016, all retrieved from publicly available resources (CEN, 2018) and Bergen and Muñoz (2018). While the original data set includes 8760 hourly observations for year 2016, we find that it is possible to capture a relatively large fraction of the variance of demand, hydro, wind, and solar profiles using only 25 representative time blocks selected using the K-means clustering algorithm (Munoz and Watson, 2015; Munoz et al., 2016). As shown in Fig. A.8 in the Appendix, the total within-clusters sum of squares decreases more slowly with more than 20 clusters. We also include the 2 observations of minimum and maximum demand for the system, as in the constrained variant of the clustering method (Wagstaff et al., 2001).

We consider three scenarios for hydro power (dry, average, and wet) and three for natural gas prices (low, medium, and high) based on historical data. Since most of the gas used for electric power generation in Chile is imported from distant locations in liquefied form, our scenarios of gas prices include both gas prices at a reference location (i.e., Henry Hub) plus transportation and regasification costs in Chile. Nevertheless, throughout our analysis we refer to natural gas instead of LNG imports because we do not explicitly model LNG infrastructure. Additionally, following the current rules of the SO in Chile, we assume that generation firms can report natural gas contracts as either flexible or inflexible. Under both types of contracts the SO finds the most efficient use of the reported contracted quantities for the year, taking the contracted volumes as fixed parameters. If a contract is reported as flexible, the SO optimizes all available resources assuming that the fuel cost of the gas-powered units owned by the firm with a flexible contract is equal to *GC*. In contrast, if the natural gas contract is reported as inflexible (e.g., due to a take-or-pay clause), the SO optimizes energy resources assuming that the cost of natural gas is equal to zero in Eq. (1).[5] These three sets of scenarios result in the 18 cases listed in Table 2.

5. Results

In this section we present our numerical results. We first use Case 1 and two simple illustrative examples to understand the shape of best response functions and the impact of transmission constraints upon our results. Next, we split the 18 cases shown in Table 2 between contract types, inflexible and flexible, which facilitates the analysis of the effect of natural gas prices and hydro scenarios on gas import decisions. All odd-numbered cases consider inflexible contracts and all even-numbered cases correspond to flexible ones.

All models were implemented using the Pyomo algebraic modeling language and solved with an academic license of CPLEX 12.4 on a personal computer with an Intel Core i5 processor @2.7 GHz with 8Gb of RAM. Each run of the economic dispatch model takes approximately 5 s and identifying best response functions for one case takes at most 3 h.

We also assumed that gas import decisions could be made in discrete quantities multiple of 24 cubic hectometers ($10^6\ m^3$), denoted hm^3, which is approximately one third of the capacity of a medium-sized LNG carrier. We performed a sensitivity analysis on the step size and found that the general structure (or shape) of best response functions and Nash equilibria is not sensitive to this parameter.

5.1. Understanding the shape of best response functions

In this section we use results from Case 1 to explain the shape of best response functions. Fig. 2 shows the best response functions of firms 1 and 2 in green and blue-colored dots, respectively. We also indicate all Nash equilibria as orange-colored squares, at the intersection of best response functions. The socially-optimal import levels of natural gas are indicated using a black-colored triangle. We identified this unique solution for each case study using the planning model described in Section 3.2.

Table 2
Case studies for all possible scenarios of hydro conditions, gas prices, and contract types.

Case	Hydro scenario			Gas price *GC* [\$/*MMBtu*]			Contract type	
	Wet	Average	Dry	6.4	9.2	10.9	Flexible	Inflexible
1	•			•				•
2	•			•			•	
3	•				•			•
4	•				•		•	
5	•					•		•
6	•					•	•	
7		•		•				•
8		•		•			•	
9		•			•			•
10		•			•		•	
11		•				•		•
12		•				•	•	
13			•	•				•
14			•	•			•	
15			•		•			•
16			•		•		•	
17			•			•		•
18			•			•	•	

Note that best response functions can have decreasing and constant sections, as well as some discontinuities or jumps between adjacent strategies of the rival firm. We first present a simple example to illustrate why, in most cases, best response functions are decreasing on gas import levels. We consider two firms and a fringe. Each firm owns a gas turbine and another generation unit, subindexes indicate ownership (e.g., GT_1 is owned by Firm 1). Variables x_1 and x_2 denote natural gas import levels that, in this example, are equivalent to the amount of generation capacity from gas turbines. For simplicity, we ignore the cost of natural gas in the dispatch and only consider its opportunity cost of dispatching a more expensive generating unit. The parameter *D* denotes the demand level, which is equal in all three figures (i.e., the red vertical line).

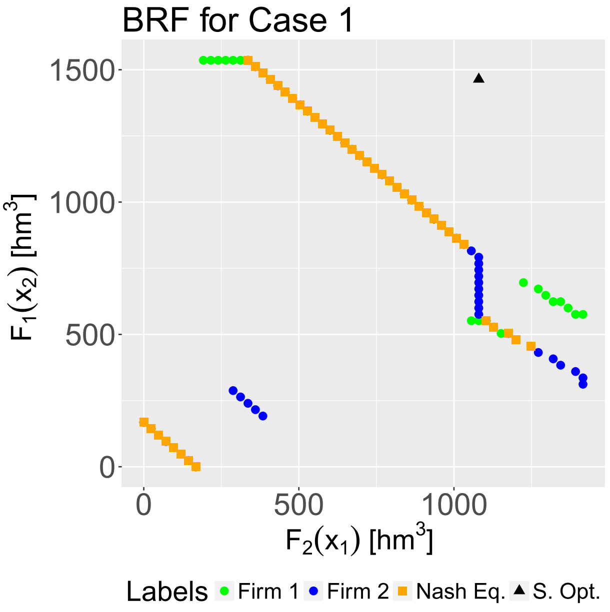

Fig. 2. Best response function for Case 1, both axes are in cubic hectometres (hm^3).

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[5] Note that here we assume that the contract types are scenarios, not decision variables for strategic firms. However, one could also model the choice of a specific type of contract, flexible or inflexible, as a strategic decision variable in addition to contract volumes x_j.

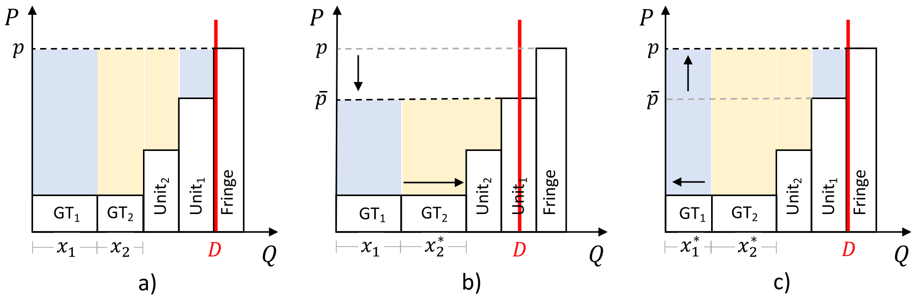

Fig. 3. Illustrative supply curves for different import levels of natural gas.

Let's consider the best response function of Firm 1 to changes in x_2, denoted $x_1 = F_1(x_2)$, and assume that these import decisions result in the fringe unit setting the clearing price p, as we show in Fig. 3 a). The light blue and yellow areas are the short-term profits of firms 1 and 2, respectively. Consider now that we want to know the best response function of Firm 1 to a new import level $x_2^* = x_2 + \Delta_2$, where Δ_2>0. As shown in Fig. 3 b), if Firm 1 maintains its import levels x_1, for a large enough value of Δ_2, the market-clearing price will drop to $\bar{p}$. The best response of Firm 1 to x_2^* will be to decrease its gas import level to $x_1^* = x_1 - \Delta_1$, where Δ_1>0, such that the fringe unit will set the market-clearing price p again. As we illustrate in Fig. 3 c), such action would allow Firm 1 to earn profits that are comparable to the ones depicted in Fig. 3 a).

Note that, in this simple example, Firm 1 will choose $\Delta_1 \approx \Delta_2$; however, in a more general setting with different gas turbines, transmission constraint and losses, and heterogeneous generation portfolios between strategic firms, the optimal reduction of gas import for one firm Δ_1 will not necessarily be equal to an increase of gas import by the rival firm Δ_2. Surprisingly, in our case study, we find that the decreasing segments of all best response functions have, roughly, the same slopes. This means that, within each segment, $F_1(x_2) + x_2 = K$ and $x_1 + F_2(x_1) = K$, where K is some strictly-positive constant. Within each of these segments, the portfolios of gas turbines owned by the strategic firms are almost perfect substitutes.

Consider now the same example, except that now Unit$_1$ is part of the fringe. In Fig. 4 a) we have the initial point x_2 and its best response by Firm 1, $x_1 = F_1(x_2)$. It is possible that, for a given Δ_2>0 and $x_2^* = x_2 + \Delta_2$, the best response of Firm 1 $x_1^* = F_1(x_2^*)$ is to maintain its import level at x_1 (i.e., $x_1^* = x_1$). This occurs because the profit loss due to a reduction in gas imports by Firm 1 $\Delta_1 = x_1^* - x_1$ is greater than increase in profits due to a raise in the market-clearing price from p to $\bar{p}$. In our experiments, we find that flat or constant sections of best response functions are common in two situations. One is when the rival firm chooses to import a large volume of natural gas, such that the best response is to import a fixed amount for a range of imports of the rival firm. The other case is when the rival firm imports a small amount of natural gas, but the firm in question faces a capacity limit. In Fig. 2 we find that this occurs for Firm 1 when Firm 2 selects import levels between 200 $hm^3$and 300 hm^3. Importing more gas is unprofitable for Firm 1 because the gas turbines that are part of its portfolio operate at their nameplate capacity.

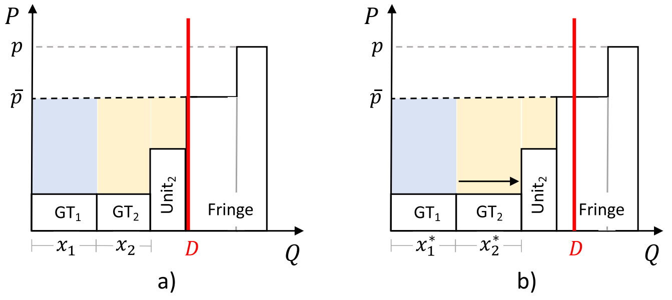

Fig. 4. Illustrative supply curves for different import levels of natural gas.

We also observe that best response functions can also present large jumps between adjacent import decisions of the rival firm. For instance, the best response function of Firm 1 jumps abruptly from zero to nearly 1500 hm^3 for import decisions of Firm 2 between 200 hm^3 and 250 hm^3. Here we find that these discontinuities are mostly a result of a transmission constrained power system. In Fig. 5 we show best response functions for a variant of Case 1, where we removed the thermal limits of transmission lines from the model (i.e., we omitted constraints (4) and (5)). Note that all the large discontinuities observed in Fig. 2 are not present in Fig. 5. In fact, without transmission constraints, best response functions are simply downward-sloping curves, up to a point where the rival firm saturates the market with generation from natural gas and the optimal strategy becomes importing zero gas. These results are in line with Hu and Ralph (2007), where the authors illustrate how transmission constraints can cause discontinuities of best response functions of generation firms in a bid-based electricity market framed as an EPEC. However, Murphy and Smeers (2005) show that these jumps in best response functions can also appear in closed-loop investment problems without transmission constraints.

Finally, we find that the socially-optimal solution involves importing nearly zero gas for firm 1 and approximately 1100 hm^3 for firm 2. In the absence of transmission constraints, this is an expected result for two reasons. First, some of the gas units owned by firm 2 are slightly more

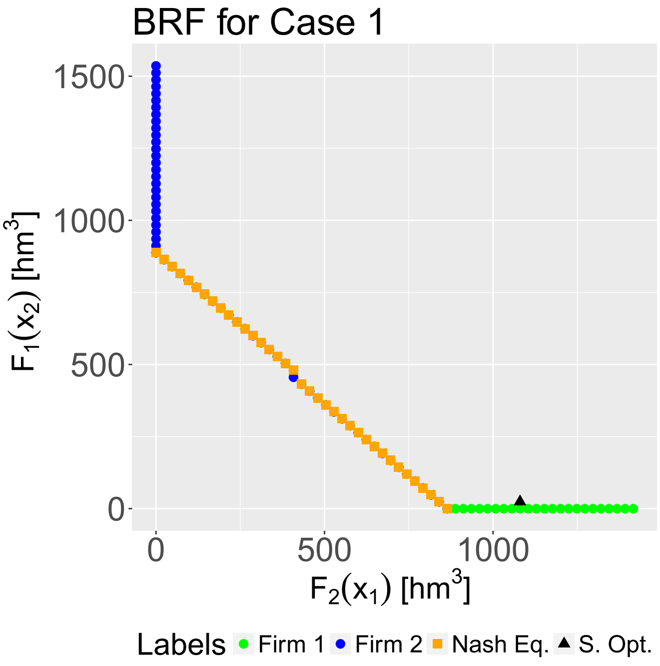

Fig. 5. Best response function for Case 1 without transmission limits.

efficient than the ones owned by firm 1. Second, importing gas only for the gas units owned by one of the firms is a corner solution of a linear program because, in the absence of transmission limits, gas units with similar heat rates become nearly perfect substitutes.

5.2. Nash equilibria for different scenarios of natural gas prices and hydro conditions

Here we present the resulting best response functions for the 18 cases considered. Our goal is to illustrate how different scenarios of natural gas prices, hydro conditions, and the type of natural gas contract affect the set of resulting Nash equilibria in each case. Figs. 6 and 7 show best response functions for the cases with inflexible and flexible gas contracts, respectively. The plots are organized in a 3 by 3 matrix, where columns indicate different gas prices and rows represent different hydro conditions. The horizontal and vertical axes in each plot indicate best responses to annual natural gas import decisions by strategic firms 1 and 2, respectively, in hm^3.

Our first observation is that the 18 cases analyzed present multiple Nash equilibria, which we were able to find by assuming discretized strategy sets for firms 1 and 2. As discussed earlier, the existence of multiple Nash equilibria in EPECs is very common due to nondifferentiability and noncuasiconcavity issues (Ehrenmann, 2004) of our equilibrium problem. Finding all possible equilibria would have been very difficult using other solution methods, such as the ones based on the iterative solution of MPECs.

We find that, in most cases, firms have incentives to import natural gas volumes that are lower than the socially-optimal levels, i.e. all cases with low or medium natural gas prices. In all of those scenarios strategic firms exercise market power. Furthermore, in scenarios of low natural gas prices we find two very distinct sets of Nash equilibria, one with high import levels and other with low import levels of natural gas (e.g., Case 2).

However, in scenarios of high natural gas prices (third column of plots) the socially-optimal outcome is contained in the set of Nash equilibria. In this set of Nash equilibria, the portfolios of natural gas units are

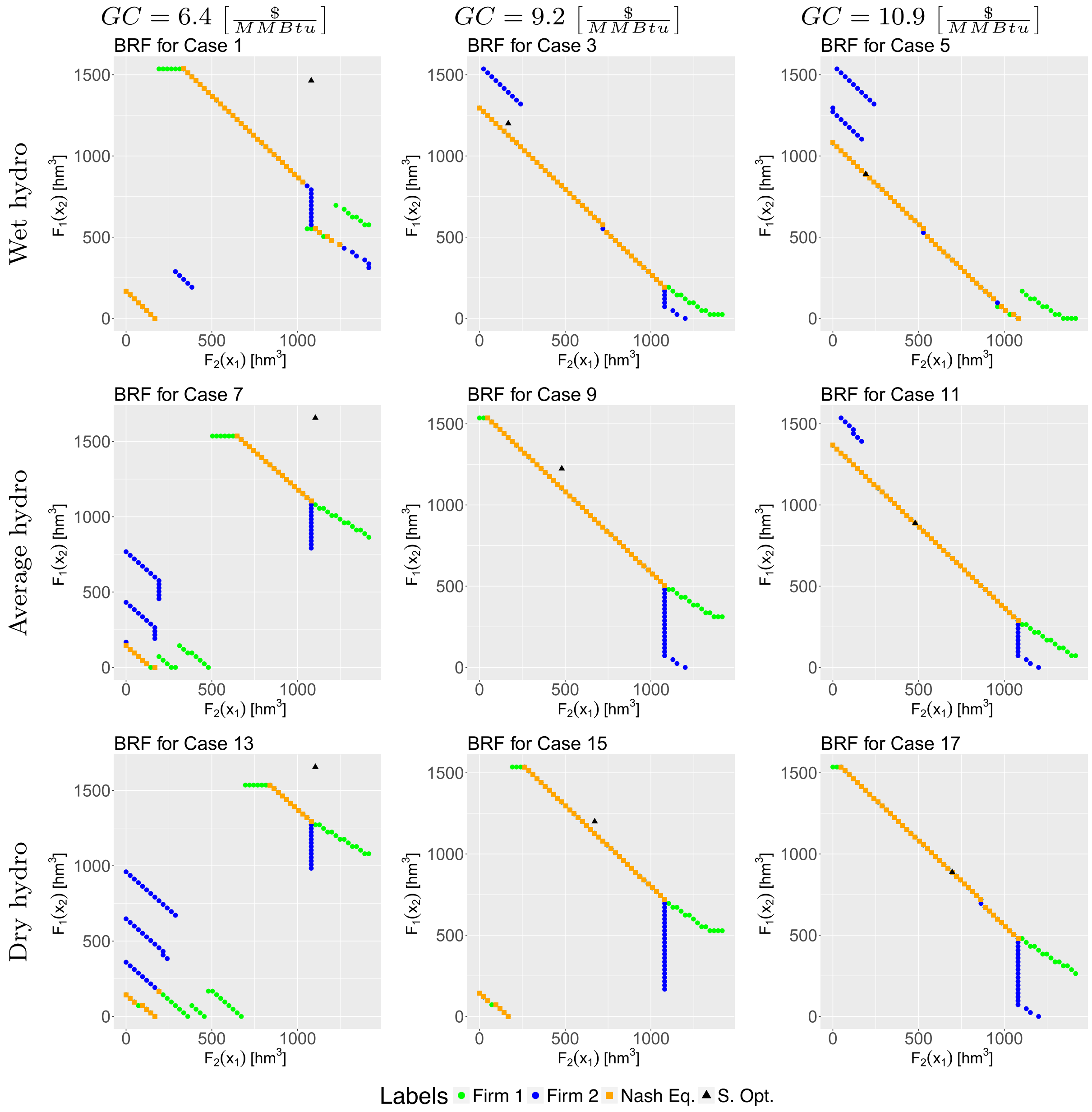

Fig. 6. Best response functions for inflexible gas contracts under wet, average, and dry hydro conditions and under the three scenarios of natural gas prices. All axes indicate annual natural gas import decisions in hm^3.

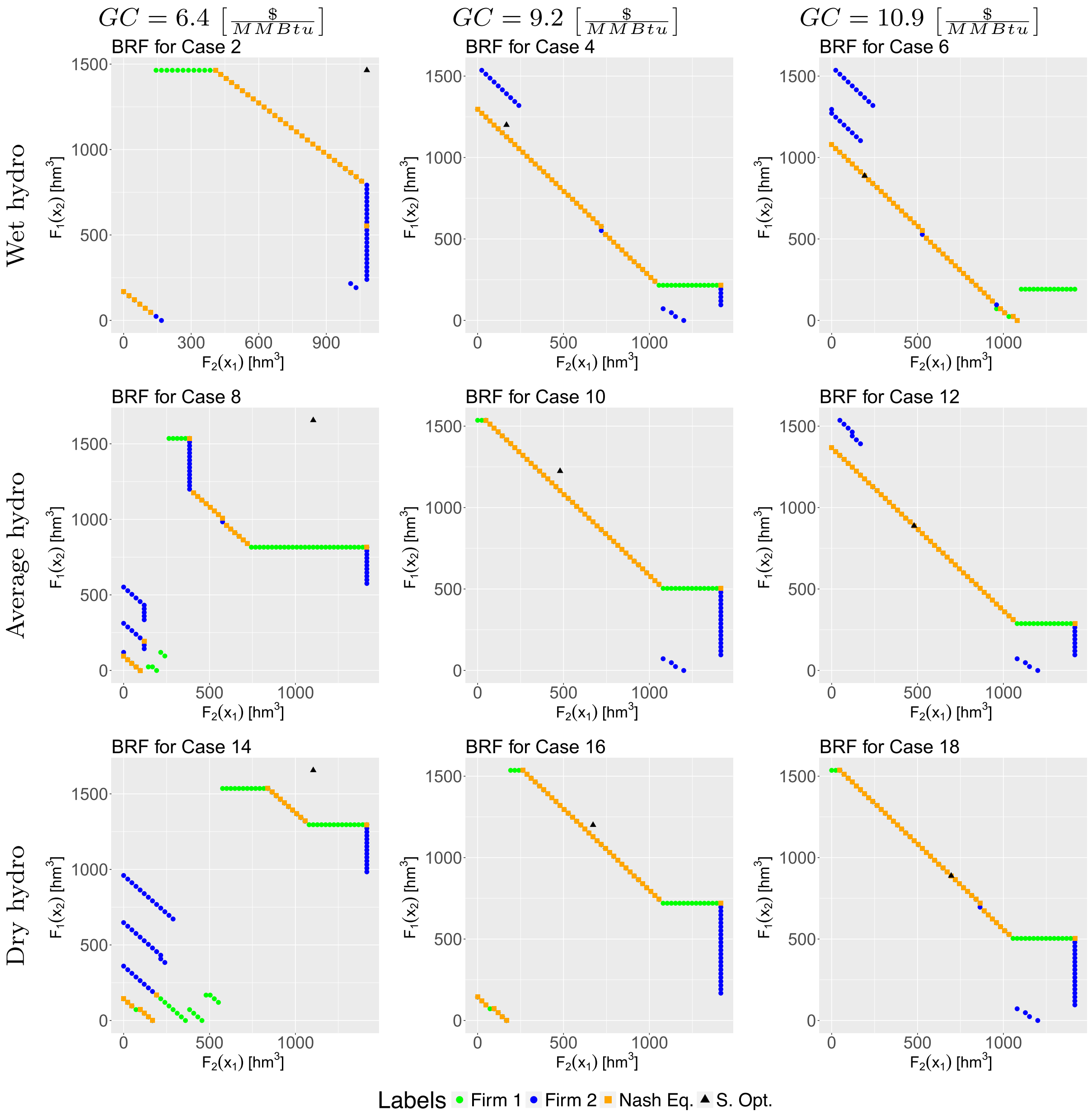

Fig. 7. Best response functions for flexible gas contracts under wet, average, and dry hydro conditions and under the three scenarios of natural gas prices.

almost perfect substitutes (straight line with slope almost equal to −1). This means that the sum of natural gas imports by firms 1 and 2 in all equilibrium points with high natural gas prices is approximately the sum of the socially-optimal import levels.

Finally, comparing Figs. 6 and 7 we observe that the type of contract (flexible or inflexible) does not seem to have a large effect upon the resulting set of Nash equilibria. The only exception are cases 7 and 8, where we observe that, under the same scenarios of hydro conditions and natural gas prices, the set of Nash equilibria that is closest to the socially optimum levels presents some sensitivity with respect to the type of contract. Given the similarity of results between cases with inflexible and flexible contracts, in the next subsections we only focus on the analysis of different scenarios of hydro conditions and natural gas prices assuming inflexible contracts (odd-numbered cases).

5.3. Natural gas import decisions and dispatch levels

We now consider a subset of the possible Nash equilibria to understand how strategic behavior leads to outcomes that can differ significantly from the socially optimal plan. We select representative Nash equilibria that are either in the middle of a set of them in a line with slope equal to −1 or the closest Nash equilibrium to the socially-optimal plan. In cases where there are multiple lines of Nash equilibria

Table 3
Aggregate natural gas import decisions for firms 1 and 2 under imperfect competition and for the socially-optimal plan.

Case	Hydro	Gas price [\$/MMBtu]	Low N. Eq. [hm^3]	High N. Eq. [hm^3]	S. Opt. [hm^3]
1	Wet	6.4	168	1872	2544
3	Wet	9.2	–	1296	1368
5	Wet	10.9	–	1056	1056
7	Average	6.4	144	2184	2760
9	Average	9.2	–	1584	1704
11	Average	10.9	–	1368	1368
13	Dry	6.4	168	2376	2760
15	Dry	9.2	168	1800	1872
17	Dry	10.9	–	1560	1560

(e.g., Case 1), we report one representative point from each set. Hereinafter, we refer to them as Low N. Eq. and a High N. Eq. Table B.10 in the Appendix shows the import volumes per firm for the representative Nash equilibria and for the socially-optimal plan.

Table 3 shows aggregate natural gas import decisions in hm^3 for the two representative Nash equilibria and the socially-optimal plan, for each possible scenario of hydro conditions and natural gas prices under inflexible contracts. We observe that both hydro conditions and natural gas prices can have an impact on import volumes. As expected, both high natural gas prices and abundant hydro resources for electricity generation reduce the incentives for firms and a hypothetical central planner to import natural gas. However, we find that the price of natural gas is the factor that results in the largest discrepancies between the socially-optimal level of natural gas imports and the procured amounts by strategic firms in equilibrium.

Now let us consider a fixed hydro scenario, Wet. We find that increasing the price of natural gas from 6.4 \$/*MMBtu* to 10.9 \$/*MMBtu* reduces the difference between the socially-optimal import levels and the equilibrium volumes with strategic firms from 26% (High N. Eq.) to 0%. In other words, increasing the price of natural gas eliminates the incentives for firms to exercise market power in the three scenarios of hydro conditions considered in this study. We observe that this occurs because the socially-optimal level of imports is much more sensitive than the equilibrium outcome with strategic firms to a change in the price of natural gas. In the Wet scenario, increasing the price of natural gas from 6.4 \$/*MMBtu* to 10.9 \$/*MMBtu* reduces the socially-optimal volume of imports by 1488 hm^3, while the High N. Eq. only decreases by 816 hm^3.

We also find that Low N. Eq. only exist in a subset of scenarios, but the effect of natural gas prices and hydro conditions on aggregate import volumes is rather ambiguous. Take, for instance, the three cases with a natural gas price of 6.4 \$/*MMBtu*. In the scenario of Wet conditions, the aggregate procured volumes by strategic firms is 168 hm^3. In the scenario of Average hydro availability, these resources are more abundant than in the Wet scenario and strategic firms procure 144 hm^3 of natural gas, 24 hm^3 less than in the Wet scenario. However, in the scenario of Dry hydro conditions, the aggregate procured amount of natural gas in the Low N. Eq. is 168 hm^3, which is 24 hm^3 higher than in the Average scenario.

Table 4 shows annual generation per technology per year for the two strategic firms and the competitive firm. For simplicity, we only consider the Wet scenarios of hydro availability since changes in dispatch levels for the remaining cases are akin to the ones shown in this table. We only include gas and diesel generation because those are the two types of generation technologies that are most sensitive to changes natural gas import decisions of strategic firms.

We observe that, even under Wet hydro conditions, diesel units can be used for generation in the socially-optimal plan if natural gas prices are not low (cases 3 and 5). As we will see in the next section, the operation of these units gets reflected directly in the price of electricity. We also note that when strategic firms restrict their import volumes of natural gas, the SO increases the amount of power generated using gas turbines owned by fringe firms. Diesel units also become an economic alternative to generate power for Low N. Eq. in Case 1. Nevertheless, for a medium price of natural gas (Case 3), the SO also relies on diesel units in the High N. Eq..

5.4. Effects of natural gas import decisions on electricity prices, profits, and total system costs

Table 5 shows load-weighted average electricity prices for the Low and High N. Eq. and for the socially-optimal levels of natural gas imports. Our first observation is that an increase in the price of natural gas has quite a large effect on electricity prices, profits, and total system costs, even under the socially-optimal levels of natural gas imports. For example, in the scenario of Wet hydro conditions, an increase in the price of natural gas from 6.4 \$/MMBtu to 10.9 \$/MMBtu yields a 163% increase in the average electricity price. However, if firms act strategically, the effect of a change in the price of natural gas on electricity prices is much smaller. In the High N. Eq., the same increase of the natural gas price results in a 70% increment of the average electricity price, from 55.4 \$/MWh to 94.4 \$/MWh. As discussed in Section, strategic firms have more incentives to exercise market power in scenarios of low than in scenarios of high natural gas prices. This feature explains why the model of central planning or price-taking firms is more sensitive to changes in the price of natural gas than the model of imperfect competition with strategic firms.

Table 6 shows total system costs for the socially-optimal import volumes of natural gas and welfare losses for the Low N. Eq. and High N. Eq. with respect to the socially-optimal outcome. Since we assume that the demand for electricity is perfectly inelastic, we measure welfare losses as the difference in total system cost between the outcome with strategic firms and the socially-optimal plan.

We find that welfare losses can be as high as 92.8% of total system costs if Low N. Eq. occur (Case 13), but they are at most 15.3% if strategic firms reach High N. Eq. (Case 1) in the closed-loop equilibrium model. As expected, if Low N. Eq. do not exist, the largest welfare losses occur in scenarios of low natural gas prices (6.4 \$/MMBtu), because it is in those scenarios where we observe the largest increase in electricity prices under the High N. Eq. with respect to the social optimum.

Table 7 shows annual profits for the two strategic firms. Again, it is in the scenarios of low natural gas prices (6.4 \$/MMBtu) and High N. Eq. when profits for strategic firms are much larger than under the socially-optimal import levels of natural gas. For instance, in Case 1, in the High N. Eq., Firm 1 earns 162.5% more profits than in the social optimum. However, in Case 2, Firm 1 only earns 6.5% more than in the social optimum.

Although we do not show them in the table, we also computed profits for all generation units in the fringe, for all the cases considered in this study. We found that all generators that are part of the competitive fringe earn higher profits when strategic firms exercise market power than under the socially-optimal plan. This means that, in our case study, all welfare losses are experienced by consumers that face electricity price spikes when strategic firms choose to restrict their import levels of natural gas. However, this is not a general result and it is possible that using a more detailed model, with less aggregated generation data and a more detailed transmission network, some units in

Table 4
Generation per technology for the strategic firms and the competitive fringe in GWh/year.

Firm	Technology	Case 1			Case 3		Case 5
		Low N. Eq.	High N. Eq.	S. Opt.	High N. Eq.	S. Opt.	S. Opt.
Firm 1	Gas turbines	381.1	6098	7749.6	5971	6352.1	4700.6
	Diesel	0	0	0	0	0	0
Firm 2	Gas turbines	482.8	3620.7	5428.8	844.8	844.8	844.8
	Diesel	180.6	0	0	453.7	391.2	657.5
Fringe	Gas turbines	11,174.4	4105.3	762.8	4061.1	4030.8	4169.5
	Diesel	1341.7	0	0	2472.2	2185.9	3560.2

Table 5
Load-weighted average electricity prices under imperfect competition and for the socially-optimal plan.

Case	Hydro	Gas price [$/MMBTtu]	Low N. Eq. [$/MWh]	High N. Eq. [$/MWh]	S. Opt. [$/MWh]
1	Wet	6.4	70.4	55.4	35.9
3	Wet	9.2	–	80.4	77.2
5	Wet	10.9	–	94.4	94.4
7	Average	6.4	87.9	55.5	36.0
9	Average	9.2	–	80.6	77.3
11	Average	10.9	–	94.5	94.5
13	Dry	6.4	107.2	55.9	36.2
15	Dry	9.2	107.2	81.2	77.9
17	Dry	10.9	–	95.3	95.3

the fringe could be worse off if strategic firms exercise market power through natural gas imports.

6. Conclusions

Market power is an important subject of research in electricity markets, particularly because of the lack of demand elasticity and the physical constraints present in power systems. Most of the existing literature on market power in electricity markets focuses on strategic bidding in wholesale bid-based markets. However, as demonstrated in Munoz et al. (2018), even in cost-based markets—where firms are not allowed to bid—firms might still be able to exercise market power in more subtle manners, such as choosing strategic investment portfolios.

In this article we contribute to the existing literature of equilibrium modeling with a new closed-loop equilibrium model to study the potential incentives of generation firms to exercise market power through natural gas imports. This work is inspired by the current setting in the electricity market in Chile, where natural gas import decisions are made several months ahead of market operations.

We frame our closed-loop model of imperfect competition as an Equilibrium Problem with Equilibrium Constraints (EPEC), where strategic firms first commit to fixed import volumes of liquefied natural gas that become available later, in a perfectly competitive short-term electricity market. As it is well known in the operations research literature, EPECs can be very difficult to solve. However, since we focus on imports of liquefied natural gas transported by tankers in discrete quantities, we can map the full space of possible outcomes of the lower-level game, where the system operator determines optimal dispatch decisions and locational marginal prices in a perfectly competitive short-term electricity market. The discretization of the decision space of strategic firms allows us to find all possible Nash equilibria of the game.

We use a simplified 9-node representation of the transmission system in Chile and assume that the two largest generation firms are strategic with respect to their import decisions of liquefied natural gas for electricity generation. As expected, we find multiple Nash equilibria that we group as High Nash Equilibria and Low Nash Equilibria. Our results indicate that, under certain scenarios of hydro and natural gas prices, firms can have incentives to restrict their import volumes of liquefied natural gas by an average of 14% and 91%, approximately, with respect to the socially-optimal levels in the High N. Eq. and Low N. Eq., respectively. As we show in our results, these decisions can have large impacts on electricity prices, total system costs, and profits for generation firms.

Table 6
Welfare losses for the models with strategic firms and total system cost for the socially-optimal plan. We report welfare losses as the difference of total system cost between the models with strategic firms and the socially-optimal plan, measured as a percentage of the latter.

Case	Hydro	Gas price [$/MMBTtu]	Low N. Eq.	High N. Eq.	S. Opt. [$M]
1	Wet	6.4	80.4%	15.3%	1452.2
3	Wet	9.2	–	2.5%	1735.7
5	Wet	10.9	–	0.0%	1890.9
7	Average	6.4	91.4%	12.3%	1522.2
9	Average	9.2	–	4.2%	1831.3
11	Average	10.9	–	0.0%	2006.4
13	Dry	6.4	92.8%	7.9%	1561.7
15	Dry	9.2	62.0%	2.5%	1901.4
17	Dry	10.9	–	0.0%	2086.2

Table 7
Profits per firm for the models with strategic firms and for the socially-optimal plan. Profits for the models with strategic firms are reported as the difference between what firms get under the equilibrium in question versus what they would obtain in the socially-optimal plan, measured as a percentage of the latter. We only show the case numbers and omit the description of hydro scenarios and gas prices due to space limitations.

Case	Firm 1			Firm 2		
	Low N. Eq.	High N. Eq.	S. Opt. [$M]	Low N. Eq.	High N. Eq.	S. Opt. [$M]
1	213.8%	162.5%	179.4	210.6%	181.6%	181.9
3	–	6.5%	765.0	–	5.7%	655.8
5	–	0.0%	956.0	–	0.0%	861.2
7	349.1%	216.9%	158.0	351.9%	185.6%	155.7
9	–	7.0%	730.1	–	5.5%	639.5
11	–	0.0%	909.2	–	0.0%	848.0
13	481.7%	231.8%	149.8	516.5%	203.3%	140.7
15	22.2%	7.0%	709.2	37.2%	7.0%	626.9
17	–	0.0%	886.3	–	0.0%	836.6

Nevertheless, the incentives to exercise market power through strategic import decisions are sensitive to the availability of hydro resources and the price of natural gas. We find that, out these two sensitivities, it is the price of natural gas in international markets that makes the largest difference. As the price of natural gas decreases, the socially-optimal volume of natural gas that would be procured by a central planner increases. Strategic firms also have incentives to increase their procured volumes of natural gas as the price of this fuel decreases, but the magnitude of this change is much smaller than the one we observe in the scenario without strategic firms. We find that the largest deviations from the socially-optimal import levels occur in the scenario when the price of natural is low. In contrast, when the price of natural gas is high, the socially-optimal plan belongs to the only set of Nash equilibria with strategic firms. As we point out in our discussions, this set of Nash equilibria is such that the sum of the import volumes for both strategic firms is approximately constant across all points in the set. These conclusions hold for the two types of contracts considered in this study, flexible and inflexible.

Although we show an application of the equilibrium model to the electricity market in Chile, we believe that some of our main results are transferable to other power systems where natural gas plays an important role in the electricity market. Japan, for instance, imports almost all of its liquefied natural gas, which became the preferred fuel source to generate power after the Fukushima nuclear accident. In South America, Perú generates more than 30% of its electricity using natural gas. In North America, tight conditions of natural gas supply have had an impact in the electricity markets of California, Texas, and Northeastern states. By mentioning these examples, we are not suggesting that generation firms in those markets have the same incentives we show in this paper to reduce their natural gas contract volumes in order to increase their profits in the electricity market. Instead, we claim that in electricity markets where natural gas plays an important role, the socially-optimal plan of natural gas procurement and usage might differ from a decentralized solution if firms have the ability to exercise market power through the gas market.

Our model and study are an extension to the models of strategic interaction with endogenous investments proposed by Kreps and Scheinkman (1983), Murphy and Smeers (2005), Wogrin et al. (2013b), and Munoz et al. (2018). This is because natural gas import volumes can be interpreted as capacity precommitments by strategic firms. With that regard, our results show some common features with the existing literature on strategic generation investment in electricity markets. Some of these include the nonmonotonic behavior of best response firms, the potential existence of multiple equilibria, and the ability of generation firms to exercise market power through natural gas import decisions while participating in a perfectly-competitive electricity market in the short run.

Of course, our study has several limitations that should be explored in future research; here we highlight three important ones. First, we disregard the existence of vertical arrangements or long-term contracts between generation firms and consumers. As demonstrated in Bushnell et al. (2008), generation firms that hold long-term financial positions have less incentives to exercise market power in wholesale markets than firms that only profit from their participation in the spot market. The model presented in this article could be extended to account for long-term contracts (e.g., as contract for differences) by including this information in the utility functions of strategic firms. While we do not address this question in our study, we hypothesize that, as in Bushnell et al. (2008), contracts could reduce the incentives of firms to restrict their import decisions of natural gas. In such case, the results presented in this article would provide an *upper bound* on the level of market power that firms could actually exercise in practice. However, we believe that the effectiveness of such contracts to reduce market power will be sensitive to the specifications of these long-term commitments. This is because, in congested transmission networks, the locational marginal price at the contractual point of delivery might not have a perfect correlation with the locational marginal prices faced by the generation units owned by a firm. Furthermore, some contracts can be indexed to electricity spot prices, which reduces the risk borne by generation firms if spot prices increase due to scarcity of natural gas.

A second main limitation of our study is the assumption of perfect forecasts about future demand levels, resource availability (e.g., hydro conditions), electricity prices, and dispatch levels. In reality, all of these factors are uncertain. Our results indicate that, under perfect information, the type of contract—flexible or inflexible–does not make much of a difference in terms of the incentives to restrict import volumes that result in higher electricity prices. However, we believe that, under uncertainty, the type of contract could make a large difference, particularly in cases where firms are risk averse. In such situations, we expect that the optimal import volume for a risk-averse firm that can engage in a flexible contract will be larger than the optimal volume for the same firm, but with the unique option of an inflexible contract with take-or-pay clauses. This type of behavior could make market monitoring very difficult. Regulatory intervention is often justified when firms have the ability to exercise of market power that could lead to large welfare losses. However, risk aversion is just a preference and not a market failure. If firms are risk averse, the only regulatory intervention that could be justified is to ensure that markets to trade risks have adequate levels of liquidity (de Maere d'Aertrycke et al., 2017).

The third limitation is related to our assumption that the only decision variables in the equilibrium problem are natural gas imports in the upper-level game and dispatch decisions in the lower-level game. In reality, if generation firms could exercise market power over extended periods of time (e.g., many years in a row), in the long run, there would be incentives for entry of new generation capacity, which would reduce market power (Murphy and Smeers, 2005; Munoz et al., 2018). Our model could be extended to capture this effect by considering investment decisions prior to natural gas imports and electricity market operations. One possible alternative is to include an upper-level game prior to natural gas import decisions, meaning that firms make investment decisions with full knowledge of the effect that such decisions have on their natural gas import decisions and, subsequently, on dispatch levels and electricity prices. We hypothesize that consideration of investment decisions would affect our results and that the incentives to exercise market power would be lower than our estimates considering fixed capacity. Nevertheless, solving such games requires a much more sophisticated approach to find all Nash equilibria than the one we employed in this paper (e.g., Pozo et al. (2012) and Abada et al. (2017)).

CRediT authorship contribution statement

Mauricio Fernández: Software, Formal analysis, Data curation, Visualization.**Francisco D. Muñoz:**Conceptualization, Methodology, Supervision, Writing - original draft, Writing - review & editing, Project administration, Funding acquisition.**Rodrigo Moreno:**Conceptualization, Writing - review & editing.

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Appendix A. Case study

A.1. Time-dependent data

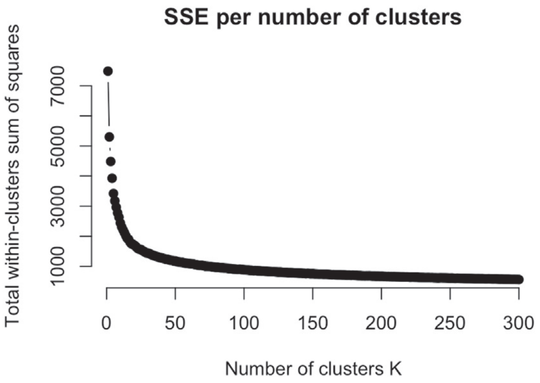

Fig. A.8. Total within-clusters sum of squares versus number of clusters for the data set of demand, hydro, wind, and solar profiles.

A.2. . Transmission system

Table A.8
Thermal limits of transmission lines in the 9-node network reduction of the main electric power system in Chile.

Transmission lines (node to node)	Capacity (MW)
CenterSIC - SICAncoa	2806
NorthCenterSIC - CenterSIC	1439
CenterSING - NorthCenterSIC	1439
SICAncoa - SICCharrua	3479
SICCharrua - SouthernSIC	2028
NorthernSIC - NorthCenterSIC	715
CenterSING - SouthernSING	691
NorthernSING - CenterSING	473

A.3. . Operating costs of generation technologies in the Chilean system

Table A.9
Summary of marginal operating costs for different generation technologies. Note that two generating units that use the same fuel can have different heat rates.

Technology	Mean MC	Min MC	Max MC
	[$/MWh]	[$/MWh]	[$/MWh]
Biogas	9	9	9
Biomass	4	4	4
Coal	32	28	40
Petcoke	29	29	29
Diesel	146	76	208
Gas turbine (GC = 10.9 [$/MMBtu])	95	69	114
Gas turbine (GC = 9.2 [$/MMBtu])	80	58	96
Gas turbine (GC = 6.4 [$/MMBtu])	55	39	66

Appendix B. . Representative Nash equilibria

Table B.10
Import levels for firms 1 and 2 for each representative Nash equilibrium point and for the socially-optimal outcome. All values are in hm^3.

Case	Low N. Eq.		High N. Eq.		S. Opt.	
	x_1	x_2	x_1	x_2	x_1	x_2
1	72	96	1152	720	1464	1080
3	–	–	1128	168	1200	168
5	–	–	–	–	888	168
7	72	72	1344	840	1656	1104
9	–	–	1176	408	1224	480
11	–	–	–	–	888	480
13	72	96	1464	912	1656	1104
15	72	96	1152	648	1200	672
17	–	–	–	–	888	672

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