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Analyzing the Impact of Electricity Market Structure Changes and Mergers: The Importance of Forward Commitments

David P. Brown
University of Alberta

Andrew Eckert
University of Alberta

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by

David P. Brown† and Andrew Eckert‡

Abstract

We investigate how the effects of market structure changes and mergers in restructured electricity markets depend on the level of forward contracting. Following Bushnell, Mansur, and Saravia (2008), we develop a Cournot model of Alberta's wholesale electricity market that incorporates firms' forward positions. Using data from 2013 - 2014, we estimate the monthly forward positions of the five largest firms in the market, and simulate the effects of different market structure changes, including variations of a hypothetical merger with asset divestitures. We examine the sensitivity of the simulated effects of mergers and other market structure changes to assumptions regarding firms' forward commitments. We demonstrate that the wholesale market impacts of mergers and market structure changes depend critically on firms' forward commitments in the post market structure change equilibrium. Our paper demonstrates the importance of establishing a clear understanding of the size and nature of forward commitments in forecasting the effects of mergers and other market structure changes in wholesale electricity markets.

Keywords: Electricity, Mergers, Forward Contracts, Market Power
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† Department of Economics, University of Alberta, Edmonton, Alberta T6G 2H4 Canada (dpbrown@ualberta.ca).

‡ Department of Economics, University of Alberta, Edmonton, Alberta T6G 2H4 Canada (aeckert@ualberta.ca).

1 Introduction

Conventional market structure analyses that are frequently used to assess the impacts of horizontal mergers do not perform well in evaluating market power in electricity markets (e.g., see Borenstein et al. (1999)). As a result, Cournot simulation analyses are frequently used to assess the effects of a merger or other market structure changes. Examples include Morris and Oska (2008) and McRae and Wolak (2009) (analyzing the proposed Exelon-PSEG Merger), Wolak (2011) (Exelon and Constellation), Morris (2000) (Union Electric and Central Illinois Public Service), Nilsson (2005) (Swedish companies Sydkraft and Graninge), and Moselle, Newbery, and Harris (2006) (assessing hypothetical Dutch mergers).

A complication arising in merger simulations in wholesale electricity markets is the presence of forward markets, as well as spot market competition. A firm's forward commitments have been shown to have a significant impact on its incentives to exercise market power in the spot market (Wolak 2000, 2007), and hence it is important to account for forward positions when analyzing the effects of a proposed merger. Two specific difficulties, however, arise. First, while data on spot market bidding behaviour and market outcomes is abundant, information on firms' forward contracting is more difficult to obtain. Merger analyses, and market power studies more generally in the the electricity industry, often need to make assumptions regarding firms' forward positions based on industry sources.[1]

A second difficulty is the potential for firms (both merging and non-merging) to adjust their forward positions following the merger. Several recent theoretical studies have considered endogenous forward contracting and the effect of changes in market structure. In general, much of this literature builds on early analysis by Allaz and Vila (1993), in which risk-neutral firms forward contract for strategic commitment reasons. Examples include Bushnell (2007), which examines the change in forward contracted quantities in response to an increase in the number of symmetric firms, and Miller (2013), which considers mergers among symmetric firms with constant marginal costs. While these models make the general prediction that firms will reduce their forward contracting as the market becomes more concentrated, because of restrictive assumptions little can be said about the magnitude of this effect that can be taken to the analysis of a specific transaction. Most recently, Brown and Eckert (2016) incorporate strategic forward contracting into a model of mergers, in which a firm's marginal cost depends on its capital stock. While this analysis provides a setting in which mergers may indeed be profitable, it too makes assumptions that limit its use as a model for practial application in antitrust settings. As well, these models are not well suited to addressing partial mergers or mergers with asset divestitures that arise often in practice.[2]

Possibly as a result of data limitations and a lack of detailed theoretical models on endogenous forward contracting, analyses of proposed mergers that incorporate forward contracting have been limited. For example, Moselle, Newbery, and Harris (2006) consider a Cournot model in which firms have sold certain quantities in advance at fixed prices in their analysis of hypothetical Dutch mergers. However, forward contracting (as a percentage of sales) is held constant post-merger, and the method through which the quantity of forward contracted output was estimated is not discussed. Wolak (2011) uses a Cournot model and calibrates the forward contracted quantities of the firms to fit observed market outcomes pre-merger in his evidence regarding the potential price effects of the merger of Exelon and Constellation. The author

[1] For example, Sweeting (2007) assumes for England Wales that 80% of a firm's output is covered by forward contracts, but cites reports suggesting the true number could be over 90%.

[2] As an example, Wolak (2011) and Willig (2011) analyze the potential Exelon - Constellation merger with divestitures.

notes the potential for the merging firms to reduce forward contracting because of their increased ability to exercise market power. In addition to simulating the merger holding forward contracting constant, the author also considers a sensitivity analysis in which the fixed-price forward contracts of the merging firms are approximately half of their pre-merger values. The author finds "that if even the parties' recommended divestiture occurs and the assets are sold to a new entrant or a firm in the price-taking fringe, market prices can rise substantially after the merger if the level of fixed-price forward contracts held by merging parties falls by a sufficiently large amount" (Wolak, 2011, pg. 25).

The purpose of this paper is to examine empirically the role played by assumptions regarding forward contracts in the simulation of merger effects and market structure changes. Following Bushnell et al. (2008), we develop a Cournot model of the Alberta wholesale electricity market that incorporates firms' forward positions. Using data for the 2013-2014 period, and estimates of unit-level marginal costs developed in Brown and Olmstead (2016), we estimate the monthly forward positions of the five largest firms in the market. We then simulate the effects of different hypothetical market structure changes, including a merger with different asset divestiture scenarios. Finally, we examine the sensitivity of the simulated effects of mergers and market structure changes to assumptions regarding firms' forward commitments.

We illustrate that the impacts of mergers and market structure changes depends critically on the level of firms' forward commitments. In addition, we demonstrate that a partial merger that results in limited changes in standard concentration measures can result in large wholesale market price effects due to the nature of firms forward commitments. Transferring generation capacity from a firm with a large forward position to one with limited forward position can result in an increase in overall wholesale market power. This emphasizes the issues associated with the use of concentration measures in the electricity industry.

Ignoring the size and nature firms' forward commitments can lead to biased conclusions regarding the competitive effects of proposed mergers or market structure changes in antitrust cases. These findings highlight the importance of establishing a clear understanding of the nature of firms' forward contracts when analyzing the effects of mergers and market structure changes. In our analysis, the implication of asset divestitures depend on the firms acquiring the divested assets, and how firms adjust their forward commitments. Our paper contributes to the literature on merger analysis in electricity markets, and also to the literature on remedies in merger cases.

The remainder of the paper will proceed as follows. Section 2 provides an overview of forward contracting in Alberta and elsewhere. Section 3 describes the Alberta market design and structure. The model is developed in Section 4. Data and estimation are described in Section 5. Section 6 presents the results of our empirical model for the current market structure, including our calibrated forward contracting levels. Section 7 presents the simulated results of our counterfactual analyses, assuming that forward contracted quantities are unchanged. Section 8 examines the sensitivity of these results to changes in firms' forward contracted quantities. Section 9 concludes.

2 Forward Contracting

In addition to buying and selling in the spot market, firms can engage in transactions outside of, and in advance of, the spot market. Forward contracts can reflect retail commitments for vertically integrated utilities (Bushnell et al., 2008), competitive arrangements between generators and distribution utilities

(Crew and Kleindorfer, 2002), or regulatory requirements imposed on dominant generators (Frutos and Fabra, 2012). Forward contracts can be either physical agreements to supply electricity in the future at a certain specified price, or financial contracts where one party pays the other the difference between a price agreed upon in advance and the spot market (pool) price.[3] Forward contracts for standardized products are traded in Alberta primarily through the Natural Gas Exchange (NGX) and over the counter (OTC) brokers (MSA, 2010). In various restructured markets (including Alberta), these forward contracts occur weeks, months, or years in advance of the spot market and represent the primary source of securing electricity supply (Ausubel and Cramton, 2010).

Forward contracts are viewed to reduce market risks and provide price stability to motivate investment. Forward contracts allow suppliers to hedge against low market prices and downstream retailers to hedge financial losses associated with high electricity prices. As well, forward contracts are expected to reduce market power incentives because of their ability to limit generation suppliers' exposure to prevailing wholesale prices (Wolak, 2000, 2007). In general, the greater the quantity a firm has already sold in forward markets at prices that are fixed going into the spot market, the less incentive the firm has to withhold capacity for market power reasons. As a result, firms with large quantities committed through fixed-price contracts act more aggressively in the spot market. Internationally, increased forward contracting has been promoted as a policy solution to market power issues in the spot market (Wolak, 2014).

While some forms of forward contracting are dictated by regulation, in many settings firms endogenously decide on their level of forward commitment. The theoretical literature on endogenous forward contracting in oligopolistic markets is extensive, focusing largely on whether the potential for forward contracts enhances or reduces competition in the subsequent spot market. Seminal theoretical work by Allaz and Vila (1993) models the impact of forward contracting on subsequent competition in oligopolistic markets. In Allaz and Vila (1993), risk-neutral firms selling homogeneous products can buy and sell in a forward market before competing in quantities in the spot market. In their setting, a firm has a strategic incentive to commit output in the forward market, in order to commit to more aggressive behavior in the spot market. The result is that all firms end up overselling in the forward market, yielding higher output and lower prices. Thus, the presence of forward markets is socially beneficial even when the hedging role is stripped away. Similar conclusions have been reached in studies that explicitly model the submission of bids in electricity markets (e.g., Green, 1999). It should be noted, however, that the competition enhancing role of forward markets depends on the observability by rivals of a firm's forward position (Hughes and Kao 1997). As well, it is demonstrated that when firms compete in prices, forward markets may allow firms to soften competition (Mahenc and Salanie, 2004), and that forward trading enhances the sustainability of collusion (Liski and Montero, 2006).

Most relevant to the current paper are recent studies that have looked at how forward contracting is affected by market structure. Bushnell (2007) investigates the relationship between market structure and the degree of forward contracting using a two-stage model with strategic forward contracting and Cournot spot market competition. Symmetric firms are risk-neutral and have symmetric linear marginal cost functions. The author shows that the proportion of market quantity that is forward contracted

[3] For example, suppose that a generator agrees to sell 15 MWs of electricity to a retailer at \$40/MWh in January 2014. For each hour in the contract period, the generator pays the retailer the spot price and the retailer pays the generator \$40/MWh for the contracted 15 MWs.

increases in the number of firms, and that forward contracts magnify the effect of concentration.[4] Miller (2013) extends this analysis by considering the welfare effects of mergers when firms have symmetric constant marginal costs. The author finds that the welfare losses from mergers are mitigated by exogenous forward contracting, but that when the market is highly concentrated, welfare losses can be increased in the presence of endogenous forward contracting.

Most recently, to understand how the incentives for forward contracting are affected by mergers, Brown and Eckert (2016) combine the two-stage forward contracting and Cournot competition model of Allaz and Vila (1993) and Bushnell (2007), in which risk-neutral firms compete via Cournot competition and forward contract for strategic reasons, with models used for merger analysis developed by Perry and Porter (1985) and McAfee and Williams (1992). In these models, a firm's marginal cost curve depends on its capital stock; merging allows firms to combine their capital stock, rotating downward the marginal cost curve which provides firms an incentive to merge. The model is then applied to the Alberta electricity market to examine how forward contracting adjusts in the event of a merger and to compare the price effects of a merger with fixed and endogenous forward contracting.

Brown and Eckert (2016) illustrate that firms reduce the proportion of their wholesale market output that is covered by forward contracts in the post-merger equilibrium. This is driven primarily by a reduction in the strategic effect of forward contracting. Endogenous forward contracting is found to elevate the price effects of a merger compared to a setting where forward contracts are held constant. Unfortunately, while this analysis provides useful insights into the qualitative effects of mergers on forward contracting, modeling assumptions required for a tractable model of endogenous contracting (e.g., risk-neutral firms, linear marginal cost functions, no capacity constraints) restrict antitrust authorities from employing the model for simulation purposes in an antitrust setting. In the current paper, we use the theoretical results of Brown and Eckert (2016) as a guide to analyze the price effects of market structure changes when firms' forward commitments can change in a more robust model of wholesale market competition.

3 Alberta's Electricity Market

Electricity market restructuring in Alberta began in 1996, leading to full retail and wholesale market competition by 2001. Alberta's market has several important features which make it an ideal setting for analyzing market power. First, Alberta's market, along with markets in Australia, Texas, and Europe, is an energy-only market where generators rely solely on the revenues from energy markets to cover the fixed cost of capacity investment. Second, there is a single spot wholesale electricity market. For each hour of the day, suppliers are required to offer (bid) in their total available generation capacity into the spot market. In these auctions, generation units are dispatched to supply electricity in order of their bids until electricity demand is met. The real-time market price equals the highest offer price accepted to supply electricity. Third, Alberta's market has limited regulatory mechanisms to limit firms' abilities to exercise market power. Unlike other restructured markets worldwide, there are no bid mitigation mechanisms in place to limit firms' abilities to offer electricity at prices exceeding (estimated) marginal cost.

In 2000, during the period of market restructuring in Alberta, certain generating units were virtually

[4]Newbery (2009) extends Bushnell's analysis to consider firms with asymmetric constant marginal cost and develops a residual supplier index to assess market power in electricity markets.

divested under Power Purchase Arrangements (PPAs) to address market power concerns associated with the high degree of market concentration. Under these arrangements the generation units would continue to be operated by their owners (the PPA Owner). However, the ability to offer this capacity into the wholesale spot market transfered to a PPA Buyer. These PPAs are long-term contracts with end dates ranging from 2013 to 2020. By March 2013, 4,971 MW of generation capacity (36% of aggregate market capacity) was under a PPA (MSA 2013). The expiration of these PPAs in 2020 represents a sizable and important market structure change in Alberta.

Table 1 presents the firm and generation technology characteristics of Alberta's electricity market in 2013 and 2014. Alberta's generation capacity largely consists of coal and natural gas generation units. These fuel types accounted for 84.1% and 82.3% of all capacity in 2013 and 2014, respectively. The five largest firms in Alberta's wholesale market accounted for 70.1% and 69.3% of Alberta's generating capacity in 2013 and 2014, respectively. The remaining capacity is divided across a fringe of 29 firms.[5]

Table 1: Alberta Market and Firm Characteristics

Panel A: Market Shares of Generation Capacity by Firm and Year (%)						
Year	TransCanada	TransAlta	ENMAX	ATCO	Capital Power	Fringe
2013	18.1	15.8	14.9	9.8	11.5	29.9
2014	17.9	15.6	12.7	11.8	11.3	30.7

Panel B: Market Shares of Generation Capacity by Fuel Type and Year (%)					
Year	Coal	Natural Gas	Wind	Hydro	Other
2013	47.2	36.9	7.2	6.2	2.4
2014	44.7	37.6	9.0	6.1	2.6

Notes: Generation capacities by firm, year, and fuel type are obtained from Brown and Olmstead (2016). Fringe contains 29 small firms. The Other generation category consists largely of biomass units.

In Alberta, the main participants in financial forward contracting are large generation companies, followed by financial trading firms (banks) and large companies that manage demand (retailers) (MSA, 2010a). The only vertically integrated generator-retailer during our sample period is ENMAX, which acts as the default Regulated Rate Option (RRO) provider for the Calgary region, and also competes in the deregulated side of the retail market. Over the sample period, retail electricity provided through the RRO was required to be priced based on foward prices taken from the 45-day period leading up to the month. The vast majority of ENMAX's retail sales through its competitive arm are expected to be through long-term (3 or 5 year) fixed-price contracts (MSA, 2015).

4 Model

In this section, we discuss the structural approach that will be used to model firm production decisions. In particular, we formulate a bilevel optimization problem that consists of a lower-level Cournot-Nash equilibrium model to model spot market competition and an upper-level optimization problem that uses observed market outcomes to estimate firms' forward commitments. Our model builds on the approach

[5]The largest of firm in the Fringe is the Balancing Pool which has a 5.4% market share (MSA 2013, 2014). The Balancing Pool is a government agency that controls PPA assets that were not acquired at the time of market deregulation.

of Bushnell et al. (2008), who incorporate firms' observable retail (vertical) positions into a model of spot market competition and demonstrate using data for PJM, New England, and California that a Cournot model fits observed market outcomes well when forward commitments are taken into account.

4.1 Lower-Level Cournot Model

We consider a Cournot equilibrium model of wholesale spot market competition that incorporates firms' forward (retail) commitments. For each period $t = 1, 2, ..., T$, six firms compete by simultaneously making their electricity production decisions (q_{jt}) in the wholesale market. Five strategic firms aim to maximize their profits, while a competitive fringe behaves non-strategically. We assume that wholesale electricity is a homogeneous product with a uniform price and all firms make their output decisions simultaneously.[6]

Define $C_{jt}(q_{jt})$ to be firm j's total cost of producing q_{jt} units of dispatchable output. In addition, each firm j has a certain level of must-run production output q_{jt}^{MR} that has zero marginal cost (e.g., wind production). This implies that a firm's total output is the sum of its dispatchable (q_{jt}) and must-run output (q_{jt}^{MR}). Denote $P_t(Q_t)$ to represent the inverse demand function in the wholesale market to be supplied by firms in Alberta (i.e., net of imports). Total output by firms is denoted $Q_t = \sum_{j=1}^{6}(q_{jt}+q_{jt}^{MR})$.

At each period t, firms have a certain level of forward (retail) committed output q_{jt}^f for each $j = 1, 2, ..., 6$. Define P_{jt}^f to be the forward contract price received by firm j. We take the forward commitments and prices as exogenous because by time period t, the forward commitments are fixed.[7]

For each strategic firm $j = 1, 2, 3, 4, 5$ and time period $t = 1, 2, ..., T$, firm j makes its output decision q_{jt} to maximize the bound-constrained profit function:

$$\begin{aligned} \underset{q_{jt}}{\text{maximize}} \quad & \pi_{jt}(q_{jt}, q_{\sim jt}) = P_t(Q_t)\left[q_{jt} + q_{jt}^{MR} - q_{jt}^f\right] + P_{jt}^f q_{jt}^f - C_{jt}(q_{jt}) \\ \text{subject to} \quad & 0 \leq q_{jt} \leq q_{jt}^{max} \end{aligned} \tag{1}$$

where q_{jt}^{max} is firm j's maximum available capacity and $q_{\sim jt}$ represents the production of dispatchable output from all other firms. A firm is a net seller (buyer) in the wholesale market if its wholesale production $q_{jt} + q_{jt}^{MR}$ exceeds (is below) its forward commitment q_{jt}^f. Firm j receives the spot market price only for its output in excess of its forward commitment. As a result, the firm has less incentive to withhold output to exercise market power when q_{jt}^f is large, since the benefit of increasing the spot market price is only realized on output sold in the spot market and not subject to a fixed forward price.

Focusing on interior solutions, for each firm $j = 1, 2, 3, 4, 5$ the production decision in period t in any Cournot-Nash equilibrium satisfies:

$$P_t'(Q_t)\left[q_{jt} + q_{jt}^{MR} - q_{jt}^f\right] + P_t(Q_t) - C_{jt}'(q_{jt}) = 0. \tag{2}$$

The level of forward contracting impacts firms' production decisions. The first term in (2) converges to zero as the level of forward contracts approaches firm j's wholesale output. This causes firm j to behave more competitively, lowering the wholesale market price. In fact, if the forward commitment exceeds

[6] Unlike many jurisdictions worldwide, Alberta does not have nodal (locational) marginal pricing. There is a single uniform price. Further, in the period of our sample there is limited transmission congestion.

[7] In Alberta, forward contracts either reflect largely invariant vertical retail obligations or monthly forward commitments determined in forward markets prior to spot market competition. As we note in Section 9, a more general formulation that models both firms' production and forward contracting decisions is warranted.

firm j's wholesale production ($q_{jt} + q_{jt}^{MR} < q_{jt}^{f}$), firm j is a net buyer in the wholesale market and so, it produces more output than it would if it behaved as a perfectly competitive firm.

The competitive fringe ($j = 6$) behaves as a price-taker and will supply output as long as the market price exceeds its prevailing marginal cost of production. Focusing on an interior solution:

$$P_t(Q_t) - C'_{6t}(q_{6t}) = 0. \tag{3}$$

For each period t, the wholesale market-clearing price is set as follows:

$$Q_t(P_t) = \sum_{j=1}^{6} q_{jt} + q_{jt}^{MR} \tag{4}$$

where $Q_t(P_t)$ reflects wholesale market demand. Conditions (2), (3), and (4) yields a Cournot-Nash Equilibrium for each period $t = 1, 2, ..., T$ that consists of equilibrium production decisions of each firm and the market-clearing price. As we discussed in more detail below, it will be essential to account for the constraints on the firms' production decisions (i.e., $0 \leq q_{jt} \leq q_{jt}^{max}\ \forall\ j = 1, ..., 6$). The lower-level problem can be written as a mixed complementarity program.

4.2 Upper-Level Implied Forward Commitment

We rely on supply and demand-side data to estimate the market-level residual demand function (net of imports) and each firm's marginal cost function. However, in order to numerically estimate the Cournot-Nash equilibrium we also need to have an estimate for each firms' forward contract positions q_{jt}^{f} for all $j = 1, 2, 3, 4, 5$ and $t = 1, 2, ..., T$. We rely on recent advances in numerical analysis techniques and a bilevel (hierarchical) optimization approach to estimate firms' implied forward commitments. We estimate monthly firm-specific peak and off-peak forward contract positions to reflect the types of forward commitments used in practice.

We observe each firm's production decisions $\widehat{q}_{jt}$ for a series of periods $t = 1, 2, ..., T$ and $j = 1, 2, 3, 4, 5, 6$. Denote $\mathbf{q^f}$ to be the vector of monthly firm-specific peak and off-peak forward contract positions. Therefore, using data from 2013 and 2014 and our structural model, for each strategic firm we numerically estimate the implied peak and off-peak forward contract positions for each month. Formally, using a non-linear least squares approach, we choose the vector $\mathbf{q^f}$ of implied monthly firm-specific peak and off-peak forward commitments to minimize the squared differences of the observed firm-specific output decisions ($\widehat{q}_{jt}$) and the structurally estimated firm-specific output decisions ($q_{jt}(\mathbf{q^f})$) determined by the equilibrium conditions of the lower-level Cournot-Nash equilibrium:[8]

$$\min_{\mathbf{q^f}} \sum_{t=1}^{T} \sum_{j=1}^{5} \left(\widehat{q}_{jt} - q_{jt}(\mathbf{q^f})\right)^2. \tag{5}$$

The non-linear least squares estimation translates our problem into a Mathematical Program with Complementarity Constraints (MPCC). This is a bilevel optimization problem where the lower-level takes the form of a mixed complementarity problem for each period t and the upper-level reflects a non-linear programming problem across all periods t. Recently, there has been substantial progress in establishing computational approaches and algorithms to solve these large-scale bilevel optimization problems. Recent

[8]The time-varying process that is used for identification in this non-linear optimization problem is associated with the time-specific variation resulting from the estimation of the residual market demand function detailed below.

methods rely on reformulating the bilevel programming problem into one that solves a non-linear program (Ferris et al. 2005, 2009). Similar to these studies, we reformulate the MPCC as a non-linear program and rely on standard non-linear programming methods to solve our large-scale bilevel optimization problem.[9] This allows us to simultaneously solve the lower-level optimization problem and implicitly estimate the monthly firm-specific peak and off-peak forward commitments.

Formally, we aim to minimize condition (5), with the constraints that the five oligopoly firms produce output according to condition (2), the fringe's production decision satisfies condition (3), and the market-clearing condition (4) holds. However, we also need to account for the bounded-constraints that ensure that the output of firm j is non-negative and does not exceed maximum available capacity (i.e., $q_{jt} \in [0, q_{jt}^{max}]$) for each period $t = 1, 2, ..., T$ and $j = 1, 2, 3, 4, 5, 6$. The MPCC can be written as:

$$\begin{aligned} &\underset{\mathbf{q^f},\, q_{jt},\, P_t,\, \lambda_{jt}\ \forall j,t}{\text{minimize}} \quad \textstyle\sum_{t=1}^{T} \sum_{j=1}^{5} \left(\widehat{q}_{jt} - q_{jt}(\mathbf{q^f})\right)^2 \\ &\text{subject to} \end{aligned} \tag{6}$$

$$P_t'(Q_t)\left[q_{jt} + q_{jt}^{MR} - q_{jt}^{f}\right] + P_t(Q_t) - C_{jt}'(q_{jt}) - \lambda_{jt} \leq 0 \quad \perp \quad q_{jt} \geq 0 \tag{7}$$

$$\forall \quad j = 1, 2, 3, 4, 5 \quad \text{and} \quad \forall \quad t = 1, 2, ..., T;$$

$$P_t(Q_t) - C_{6t}'(q_{6t}) - \lambda_{6t} \leq 0 \quad \perp \quad q_{6t} \geq 0 \qquad \forall \quad t = 1, 2, ..., T; \tag{8}$$

$$q_{jt} \leq q_{jt}^{max} \quad \perp \quad \lambda_{jt} \geq 0 \quad \forall \quad j = 1, 2, 3, 4, 5, 6 \quad \text{and} \quad \forall \quad t = 1, 2, ..., T; \tag{9}$$

$$Q_t(P_t) = \sum_{j=1}^{6} q_{jt} + q_{jt}^{MR} \qquad \forall \quad t = 1, 2, ..., T; \tag{10}$$

where λ_{jt} reflects the Lagrangian Multiplier on firm j's the maximum production capacity constraint and $\perp$ reflects complementarity for each period $t = 1, 2, ..., T$. (7) - (10) reflect the lower-level mixed complementarity program that constitutes the Cournot-Nash Equilibrium with a competitive fringe.[10] To implement this program, we use the Non-Linear Programming with Equilibrium Constraints (NLPEC) solver in GAMS (Ferris et al. 2009) on the external NEOS server (Czyzyk et al., 1998).

5 Data and Estimation

In this section, we discuss the data and the approach used to estimate each firm's marginal cost function and the hourly residual demand function. Throughout the analysis, all monetary values are reflected in Canadian Dollars.

5.1 Data

We use available data from the Alberta Electric System Operator (AESO) from January 1, 2013 to December 31, 2014. This data set includes observed hourly price and quantity offers for all generation firms in Alberta, natural gas prices from Alberta's Natural Gas Exchange, transmission capacity limits, import

[9]For a detailed review of the methods used to reformulate a MPCC into a non-linear program, see Baumrucker et al. (2008).

[10]The system of equations defined in (7) - (10) represents a "square" complementarity program. In the numerical program we verify that the each firm's profit functions are globally pseudoconcave and locally strictly concave at the solution to the MPCC. This ensures that the Cournot-Nash equilibrium exists and is unique (Kolstad and Mathiesen, 1991).

supply, market-level demand, generation asset-specific characteristics, and the identity and ownership of the generation assets. Further, we gather hourly weather data for British Columbia (BC), Alberta (AB), and Saskatchewan (SK) from Environment Canada: Weather Information. We acquired data on unit-specific the thermal heat rates from the MSA and AESO. Our sample includes 17,520 hours. Table 2 provides summary statistics for several market-level variables over our sample period.

Table 2: Summary Statistics

	Units	Mean	Std. Dev.	Min	Median	Max	N
Quantity Demanded	MW	8,309.87	749.87	6,181.50	8,343.2	10,442.88	17,520
System Marginal Price	\$/MWh	63.65	143.70	0	29.70	999.99	17,520
Natural Gas Price	\$/GJ	3.63	1.23	1.57	3.53	24.82	17,520
Imports	MW	260	219.08	0	200	1,072	17,520

5.2 Marginal Cost Functions

We use generation unit-level characteristics to estimate the marginal cost functions for each firm.[11] We compute the marginal cost of natural gas units in our sample using the hourly natural gas price (p_t^{NG}), unit-specific thermal efficiencies measured by the heat rate (HR_i), estimates on the variable operating and maintenance (O&M) costs, and environmental compliance costs. The estimated marginal cost of a natural gas unit reflects the summation of its fuel costs ($p_t^{NG} \times HR_i$), the variable O&M costs, and the costs of environmental regulations.

We are unable to formally model the marginal cost of coal generation technologies because coal is purchased through (unobservable) long-term contracts. We follow Brown and Olmstead (2016) and use a Monte Carlo simulation approach to estimate the marginal cost of coal units in Alberta. For each year and coal unit, an energy market bid is selected at random during an hour where there is a large amount of excess generation capacity available.[12] This bid is used as a proxy for the unit's marginal cost of production. This procedure is repeated 1,000 times. For each coal unit-year, we use the average of these 1,000 iterations to reflect the unit-level marginal cost.[13]

An increasing share of electricity generation in Alberta is arising from cogeneration and wind technologies. Cogeneration facilities produce heat and electricity as a by-product of the industrial process. These units sell all excess electricity not consumed on-site. We assume that output from wind and cogeneration have zero marginal cost.[14] Lastly, there are several small hydro units representing 2 - 3% of all electricity output in Alberta. Modeling the marginal cost of hydro units is challenging because its reflects the opportunity cost of using the stored energy at some other time. Because the wind, cogeneration, and hydro units have very low marginal cost (often zero), we define this production as "must-run". We take the amount of must-run production as given for each hour.

[11] The Appendix provides additional details on the marginal cost estimation methodology.

[12] In hours with excess production capacity, market power execution is less likely to be profitable. In these hours firms bids often reflect the prevailing marginal cost of production (Crawford et al., 2007).

[13] Using weekly coal price data from the Wyoming's Powder River Basin and unit-specific heat rates, Brown and Olmstead (2016) demonstrate that the Monte Carlo procedure yields similar estimates on the marginal cost of coal units as those established explicitly using coal price data.

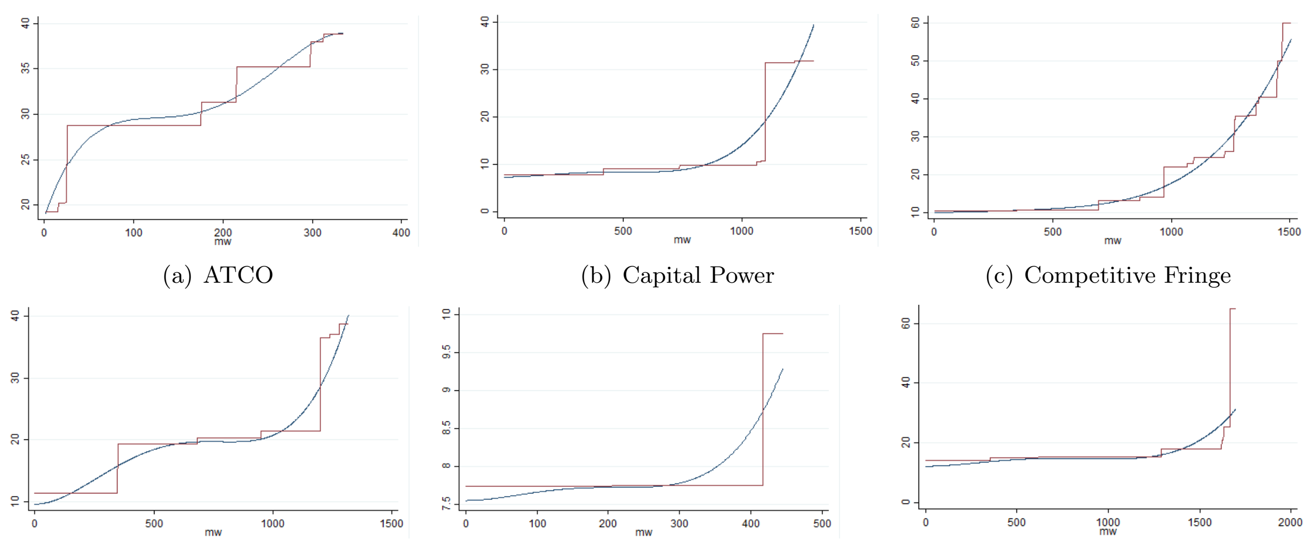
[14] All wind facilities and the majority of cogeneration units offer in all production at a price of zero into the wholesale market. Although, several cogeneration units systematically produce electricity beyond their on-site needs and submit non-zero bids. For these units, because they operate on natural gas we use unit-specific heat rates and natural gas prices to impute their underlying marginal cost as we would with a traditional natural gas facility.

Generators can potentially choose their unit availability strategically. Therefore, we use a methodology similar to Bushnell et al. (2008) and reduce the capacity of non-must-run units by the forced outage probability, derated to account for partial unit availability ($dfof$).[15] The available capacity of unit i equals $(1 - dfof_i) * cap_i$, where cap_i is the "name plate" capacity unit i (MSA, 2014).[16]

We formulate a firm's stepwise marginal cost function that consists of dispatchable (non-must-run) units for each month as follows. For each unit and month, we average the short-run marginal cost across all hours. Then, we order each firm's generation units in order of least cost, taking their capacity availability as derated as discuss above. For computational purposes, we approximate each firm's monotonically increasing marginal cost curve using a fourth-order polynomial.[17] We use GAMS software to solve this constrained non-linear minimization problem using the primal-dual interior point optimization method (IPOPT). We use the external NEOS server to implement this non-linear program (Czyzyk et al., 1998).

Figure 1 illustrates representative marginal cost functions and fourth order polynomial approximations. The average R-squared values on the marginal cost approximation for ATCO, Capital Power, Competitive Fringe, ENMAX, TransAlta, TransCanada across our entire sample are 0.92, 0.84, 0.98, 0.93, 0.87, and 0.58, respectively.[18]

Figure 1: August 2013 Marginal Cost Function Estimates



(a) ATCO

(b) Capital Power

(c) Competitive Fringe

(d) ENMAX

(e) TransAlta

(f) TransCanada

[15] Wolfram (1999) and Bushnell et al. (2008) use the forced outage factor (fof) to reflect the probability of a complete unit forced outage. We use Canadian generation unit data on fof's derated to account for partial unit outages (CEA, 2012). This better reflects observed capacity availability in Alberta, athough the key results are robust to the use of the fof.

[16] An alternative approach used in Borenstein et al. (2002) and Mansur (2007) explicitly model unit availability using Monte Carlo simulations. We are unable to use this approach due to computational complexity associated with solving the Cournot Equilibrium. Bushnell et al. (2008) find that this simplification has minimal impact on the equilibrium outcome.

[17] Bushnell et al. (2008) use a piecewise linear function with five segments and Willems et al. (2009) use a monotonically increasing cubic function to approximate firms' monthly marginal cost functions. The fourth-order approximation below largely out performs these approaches in our data set in terms of goodness-of-fit.

[18] For TransCanada, there is a small high marginal cost biomass unit with an average of 30 megawatts of capacity that fits poorly in our polynomial approximation. If this unit is removed, the average R-squared value on the marginal cost approximation for TransCanada across our entire sample increases to 0.93.

5.3 Import Supply and Residual Demand

We estimate the supply of electricity from neighboring provinces, British Columbia (BC) and Saskatchewan (SK).[19] Firms outside of Alberta make their import decisions based upon the relative price of electricity. For each hour t, the following province-specific import supply functions are estimated:[20]

$$Q_{jt}^{IM} = \beta_{0j} + \beta_{1j} p_t + \beta_{2j} \mathrm{Weekday_t} + \beta_{3j} \mathrm{Holiday_t} + +\beta_{4j} \mathrm{ImpCapacity_{jt}} + \alpha_j \, \mathrm{h(Temp_{jt})} \\ + \sum_{h=1}^{24} \omega_{hj} \mathrm{Hour_{ht}} + \sum_{m=1}^{12} \gamma_{mj} \mathrm{Month_{mt}} + \psi_j \mathrm{Year_{2014}} + \epsilon_{jt} \quad \forall \quad j \in \{BC, SK\} \tag{11}$$

where $\mathrm{h(Temp_{jt})}$ is a non-linear function of the temperature variables in province j, $\mathrm{Weekday_t}$ is an indicator for weekdays, $\mathrm{ImpCapacity_{jt}}$ is the hourly transmission line capacity (in MWs) from province j, and $\mathrm{Holiday_t}$, $\mathrm{Hour_{ht}}$, $\mathrm{Month_{mt}}$, and $\mathrm{Year_{2014}}$ are indicator variables for each provincial holiday in Alberta, hour, month, and year in our sample, respectively. To capture the relative temperatures in each province, the temperature variables used in the analysis are modeled as quadratics for hourly cooling degrees (hourly mean degrees above 65^o F (18^o C)) and hourly heating degrees (hourly mean degrees below 65^o F (18^o C)).[21] The import capacity captures variation in the physical intertie constraints. The calendar variables are included to capture systematic input supply shocks and demand variation.

The electricity price in Alberta is endogenous to the degree of imports. To address the endogeneity in price, we use an Instrumental Variable (IV) approach where the exclusive instruments are Alberta hourly temperature variables and the level of wind output (in MWs) in Alberta. Temperature and wind production in Alberta are vaild instruments because they affects the prevailing demand and supply conditions in Alberta and so, it impacts the market price in Alberta (p_t). However, temperature and wind variation in Alberta only impacts the import quantity through their impact on p_t.[22]

The first and second stage results of our IV estimation are given in Table A1 in the Appendix. The standard errors reported are robust to heteroskedasticity and autocorrelation with 24 lags. For both provinces, the Kleibergen-Paap Wald F statistic strongly rejects the null hypothesis that our instruments are weak. The estimated coefficients on price are 0.373 for BC imports and 0.064 for SK imports, and both are statistically significant at the 1% level. The coefficients imply an average price-elasticity of imports of 0.12 and 0.073 for BC and SK, respectively. More generally, 95% of the estimated province-specific price-elasticity of imports falls in the range $[0.01, 0.34]$ and $[0.02, 0.38]$ for SK and BC, respectively. This illustrates that the price-responsiveness of imports into Alberta is limited on average, after controlling for important supply and demand-side covariates. Sensitivity analysis of our results to the price parameters of the import equations is conducted in Section 8.3.

[19] There is a small transmission interconnection with Montana. However, due to the interaction with the BC intertie, the connection with Montana does not add additional transmission capacity (MSA, 2012). The limited imports from Montana are included in the estimation of the BC import supply function.

[20] The linear specification is chosen for computational ease. Alternative specifications such as log-linear increase the computational complexity of the bilevel Cournot optimization substantially. A log-linear specification increases the price-elasticity of imports (and hence, the elasticity of residual demand). While this reduces the level of implied forward contracts, the key qualitative conclusions of the analysis persist.

[21] The cities considered in AB, BC, and SK are Calgary, Edmonton, Vancouver, and Saskatoon, respectively. The results of the analysis are robust to the consideration of alternative large cities in each province and higher degree polynomials.

[22] This is particularly relevant in the current context because imports from BC and SK arise primarily from hydro and fossil fuel generators, respectively. If the imports arose from wind production, the strong geographical correlation observed in wind output would raise concerns over the validity of our IVs.

The estimated coefficients from our import supply function are used to define the price-elastic residual demand faced by the five strategic firms and the competitive fringe within Alberta:

$$Q_t(p_t) = \overline{Q}_t - \sum_{j \in \{SK,BC\}} \widehat{Q}_{jt}^{IM}(p_t) = \widehat{\alpha}_t - \widehat{\gamma} p_t \tag{12}$$

where $\overline{Q}_t$ is observed market-level demand and $\widehat{Q}_{jt}^{IM}(p_t)$ is the level of estimated imports from province j. Using (12), for each hour t we model inverse residual demand as:

$$P_t(Q_t) = \frac{1}{\widehat{\gamma}} \left(\widehat{\alpha}_t - Q_t \right). \tag{13}$$

6 Observed Outcomes and Estimated Forward Positions

Before proceeding to simulating the effects of various market structure changes on spot market outcomes, we review the output from the bilevel optimization program. Table 3 presents observed and estimated firm-specific average quantities and system market-clearing prices (SMP) for the Cournot model. In addition, Table 3 provides the perfectly competitive average firm-specific outputs and SMP under the assumption that all firms behave as price-takers.[23] Total output for each firm includes both must-run (MR) and non-must-run volumes.

Table 3: Average Observed, Lower-Level Cournot, and Perfect Competition Quantities and Prices

	Observed		Cournot		Perfect Comp	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QATCO	638	580	633	567	608	520
QCP	1,094	1,025	1,092	1,018	1,151	1,079
QENMAX	1,226	1,018	1,223	1,010	1,162	940
QTA	1,052	985	1,073	993	1,107	1,049
QTC	1,738	1,617	1,736	1,610	1,946	1,798
QFRINGE	2,638	2,487	2,690	2,548	2,498	2,371
SMP	94.84	37.71	85.62	50.89	28.49	21.40

Notes: The Cournot and Perfect Competition numbers represent total output. All quantity values are in MWs and the SMP is in $/MWh.

The close match between observed and Cournot quantities is to be expected, since the bilevel problem chooses firm-specific monthly peak and off-peak forward positions to minimize the sum of squared residuals between firm-specific actual and structurally estimated output. Under perfect competition, compared to observed or Cournot volumes, volumes are higher for CP, TA and TC, but fall for ATCO and ENMAX. Following the methodology employed in Puller (2007), we test the equality of actual and estimated firm-specific total output under the Cournot and Competitive benchmarks by regressing the difference between the actual and benchmark output on a constant, and computing Newey-West standard errors.

[23] When solving the perfectly competitive equilibrium, we choose the least-cost resources necessary to meet hourly residual demand. This problem takes the form of a Mixed Complementarity program and is solved using Newton's Method and the PATH algorithm in GAMS.

$$q_{jt}^{Actual} - q_{jt}^{Benchmark} = \delta + \epsilon_t \qquad \text{for} \quad \text{Benchmark} \in \{\text{Cournot, Perfect Comp}\}.$$

Under the null hypothesis $\delta = 0$, the observed and estimated benchmark firm-specific output have the same mean. Table 4 reports results of this analysis. For each firm, we can reject the null hypothesis of competitive behavior at the 1% level of significance. We reject the null that the actual and Cournot model with forward commitments quantities have the same mean for TransAlta, ATCO, and the competitive fringe. However, while these effects are statistically significant, the Cournot model with forward commitments provides a much better fit on the strategic firms' production decisions. Similar conclusions are reached when the sample is separated into peak and off-peak hours.

Table 4: Observed-Fitted Mean Outputs with Newey-West Standard Errors (24 lags)

Firm	Cournot		Perfect Competition	
ATCO	9.3***	(1.9)	45.1***	(2.4)
CP	4.9	(4.3)	-55.0***	(5.4)
ENMAX	5.6	(4.1)	71.5***	(5.4)
TA	-14.4***	(2.9)	-59.6***	(3.1)
TC	5.0	(4.6)	-193.9***	(6.9)
FRINGE	-55.9***	(6.1)	127.8***	(5.5)

Notes: Newey-West standard errors with 24 lags are reported in parentheses. *** Statistical significance at the 1% level.

Using Table 3, we compare the market prices across the observed and benchmark models. The Cournot model with estimated forward positions underestimates price on average by \$9/MWh (9%) in peak hours and overestimates price by \$13/MWh (34%) in off-peak hours.[24] The poorer match in off-peak hours may result in part because we focus on static estimates of marginal costs for coal units which often set the marginal price in off-peak hours.[25] We are most interested in the merger and market structure change price effects in peak hours where market power concerns are the highest.[26] In contrast, the perfectly competitive model drastically underestimates price in all hours, by \$67/MWh (70%) in peak hours and \$16/MWh (43%) in off-peak hours on average.

Figure 2 presents the monthly average peak and off-peak actual and estimated prices. The perfectly competitive price consistently falls below the observed and Cournot prices. Further, with the exception of April-May 2013, the Cournot model and observed prices track closely together.[27] In particular, as noted above, the Cournot model performs substantially better in the peak periods because of our ability to more accurately model the marginal cost of natural gas units that set market prices in these hours.

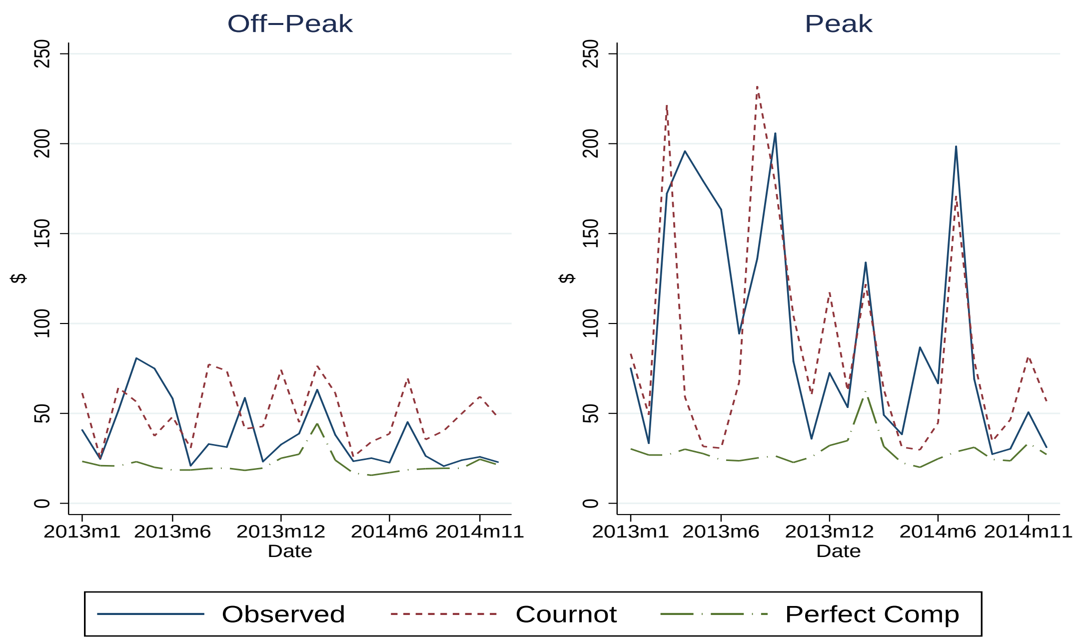
[24] Similar to Bushnell et al. (2008), we find that the Cournot model with no forward commitments fits the data poorly; for almost all hours in our sample, the Cournot model with zero forward commitments yields prices that exceeds the price-cap of \$1,000. This supports prior literature that emphasizes the importance of accounting for forward commitments (e.g., Hortacsu and Puller (2007); Wolak (2007); Bushnell et al. (2008); Regaunt (2014)).

[25] The marginal cost of coal units includes dynamic (non-convex) costs associated with ramping and turning on and off inflexible coal units. Mansur (2008) uses a reduced-form approach to illustrate the importance of accounting for these start-up costs and ramping constraints, especially in off-peak periods when coal units set prices. Due to computational complexity, we are unable to solve the non-convex unit-commitment problem in the context of our Cournot model.

[26] Brown and Olmstead (2016) illustrate that firms exercise limited market power in the off-peak hours in Alberta.

[27] In April and May 2013, there were several hours with extreme price spikes due to idiosyncratic unit outages. This elevates the observed average monthly market-clearing price. The Cournot model is unable to capture these observed prices spikes.

Figure 2: Average Monthly Off-Peak and Peak Observed and Estimated Prices



It is important to assess whether our estimated forward positions are reasonable. Table 5 reports average estimated monthly peak and off-peak forward commitments (Cournot - Forward), along with observed output and adjusted capacity for each firm. In peak hours, estimated forward contract quantities in the Cournot model as a percentage of adjusted capacity (by the derated forced outage probability) is lowest for ATCO at 64% and highest for TransAlta at 106%. The remaining firms have forward positions as percentage of adjusted capacity between 80% and 83%. For off-peak hours, these percentages decrease to 56% for ATCO, 96% for TransAlta, and from 66% to 77% for the remaining firms.[28] The Cournot estimated forward contracts represent between 91% to 106% of average observed output in the off-peak hours and 94% to 108% of average observed output in peak hours.

In general, our results suggest that in order for a Cournot model to be a good fit for TransAlta's behaviour, TransAlta must have forward commitments around or exceeding its sales volume in the spot market. This could be explained by unmodelled features of TransAlta's cost function. In particular, TransAlta's non-must-run generation capacity is largely coal based; unmodelled ramping and start-up costs could mean that once these units are operating, TransAlta has a strong incentive to keep them operating, and that as a result these units largely run around the clock.

Typically, limited public information exists regarding the degree of forward commitments. However, several studies have data on observed forward contracts and find that firm's forward contract coverage as a percentage of total output range from 73% to 103% (Wolfram, 1999; Anderson et al., 2007; Wolak, 2007; Sweeting, 2007). Similar to our analysis, several studies use observed production or bidding behavior and a structural assumption on the nature of competition to estimate firm's forward commitments (Hortascu

[28] In peak hours, the estimated forward commitments from the Cournot model as a percentage of installed nameplate capacity is lowest for ATCO at 62%, highest for TransAlta at 101%, and range between 71% and 76% for the other firms. For off-peak hours, the estimated forward commitments as a percentage of installed nameplate capacity is lowest for ATCO at 54%, highest for TransAlta at 91%, and range between 59% and 71% for the other firms.

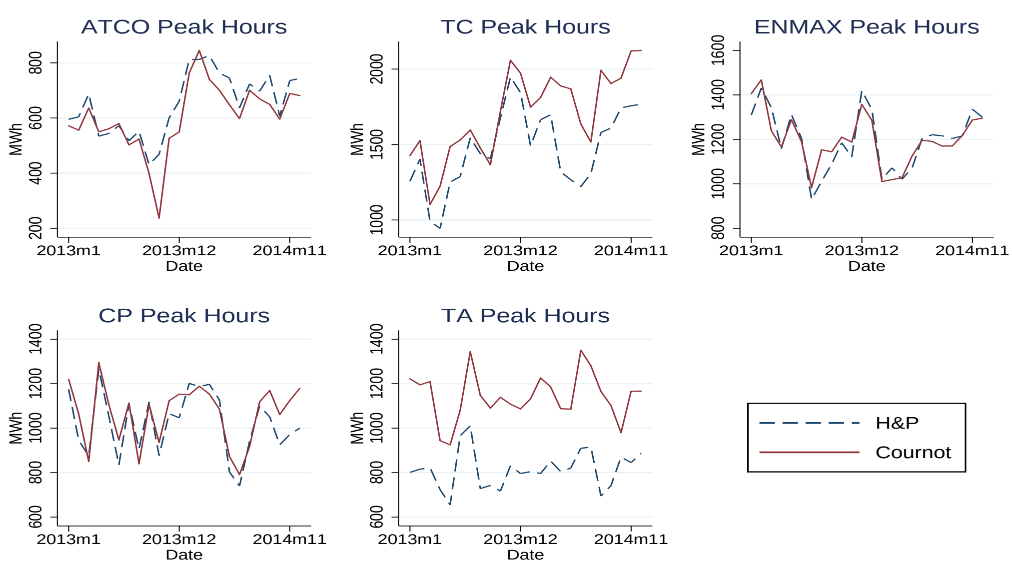
Table 5: Average Quantities, Adjusted Capacities, and Estimated Forward Positions

	Nameplate Capacity	Adjusted Capacity	Observed Output		Cournot - Forward		H&P - Forward	
			Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
ATCO	974	937	638	580	602	528	680	673
CP	1,482	1,330	1,094	1,025	1,066	1,004	1,023	932
ENMAX	1,692	1,506	1,226	1,018	1,200	998	1,197	1,025
TA	1,135	1,082	1,052	985	1,142	1,043	814	752
TC	2,238	2,065	1,738	1,617	1,707	1,595	1,475	1,451

Notes: Nameplate consists of the maximum capacity for coal and gas units and the mean available capacity for must-run units. Adjusted Capacity reflects the sum of the nameplate capacity for coal and gas units adjusted by the forced outage probability (derated to account for partial unit availability) and the mean available capacity for must-run units.

and Puller, 2008; Willems et al., 2009; Allcott, 2013; Reguant, 2014). With the exception of Willems et al. (2009), these studies find forward contract positions as a percentage of output to lie between 85% and 100%.[29] In particular, Hortacsu and Puller (2008) [hereon, H&P] rely on the theoretical foundations of the uniform-priced share auction model and finds that a firm's forward commitments can be estimated as the quantity at which the observed offer (bid) schedule intersects the marginal cost function from below. The intuition of this result relies on the fact that firms bid at or below (above) marginal cost when it is a net buyer (seller). While H&P uses an alternative assumption on the nature of strategic behavior, it is useful to compare our estimated forward contracts to those that would arise from their methodology.

Figure 3: H&P and Cournot Estimated Peak Forward Commitments



The last two columns of Table 5 show the average estimated peak and off-peak forward positions using H&P approach. With the exception of TransAlta, the bilevel Cournot model and H&P's approach yield remarkably similar average estimated peak and off-peak forward positions. This is further highlighted in

[29] Willems et al. (2009) uses both a Supply Function Equilibrium (SFE) and Cournot model to model firm behavior. Unlike these other studies, the authors find contract positions around 25% of installed capacity for the SFE model and 50% for the Cournot Model.

Figure 3, which plots both estimates of peak hour forward commitments over our sample period.[30]

As a final check of the reasonableness of our foward positions we consider ENMAX, the province's only vertically integrated generator/retailer during our sample period. As in Bushnell et al. (2008), it is possible to proxy such firms' forward positions through their fixed-price retail commitments. ENMAX sells retail electricity through both regulated default contracts and through competitive contracts. Default contracts with residential, small commercial, and industrial and farm customers during our sample period were based on forward prices for the current month. The vast majority of electricity sold through competitve contracts to these customers is expected to be under long-term fixed-price contracts. While a higher proportion of ENMAX's large commercial and industrial consumers are expected to be on wholesale price pass-through contracts, we still expect some of these consumers to be under fixed-price contracts. In general, ENMAX's estimated forward position from our model are consistent with approximations of their retail commitments under fixed prices, supposing that approximately 30% of large industrial and commercial customers are under fixed-price contracts; see Appendix B for details.

7 Counterfactuals Holding Forward Contracted Quantities Constant

In this section, we simulate the effects on prices and firm-level quantities of different hypothetical market structure changes, assuming that the forward market quantities for each firm are unchanged. We consider two different counterfactual settings. The first is an expiry of a PPA unit, with the result that offer control for these units is transferred back from the PPA buyer to the owner of the generating unit. The specific PPA units we consider are for Battle River 3 and 4, for which ATCO is the owner and ENMAX is the PPA buyer. In the second set of counterfactuals, we consider a hypothetical merger between ATCO and ENMAX. This particular merger is considered because of the contrasting forward positions for these firms estimated in the previous section. We estimate three versions of this merger: the merger approved without conditions, the merger with certain units divested to the competitive fringe, and the merger with these units divested to the other large firms. These counterfactuals demonstrate the ability of our approach to simulate transactions involving a portion of a firm's capacity and asset divestitures.[31] Our methodology is the following. First, we transfer the units in question across firms, and re-estimate the marginal cost functions and capacities of these firms. We then use the Cournot model and estimated residual demand to simulate the effects of each transaction, assuming that the forward contracted MWs of the major firms are held constant.

7.1 PPA Expirations: Battle River 3 and 4

On January 1, 2014 the offer control of two large coal units, Battle River #3 (BR3) and #4 (BR4), changed from ENMAX to ATCO due to the expiration of a Power Purchase Arrangement (PPA). This exogenous change transferred 294 MW of offer control from ENMAX to ATCO, and represented a 16% decrease in ENMAX's and 21% increase in ATCO's capacity offer control (MSA, 2014). While this event resulted in limited changes in concentration,[32] the difference in the estimated forward positions of ATCO and

[30] The results for the off-peak hours are qualitatively similar to peak hours. These results are available upon request.

[31] In contrast, Brown and Eckert (2016) focus on complete mergers in a setting of endogenous forward contracts.

[32] The combined market share of the top 4 firms was 54.7% in 2013 and 54.1% in 2014. Further, the Herfindahl-Hirschman Index (HHI) was 939.5 in 2013 and 933.4 in 2014 (MSA, 2014).

ENMAX suggests that this transfer could lead to a reduction in competition. Recall that while ENMAX was estimated to forward contract 80% of its derate-adjusted capacity, ATCO's forward position was only 64% of its derated capacity.[33] As a result, the transfer in capacity from a vertically integrated firm to a vertically separated firm may have substantial price implications because of differences in fixed-price commitments, despite resulting in little change to standard concentration measures.

To consider the potential effect of the expiration of these PPAs, we suppose that the expiration had occurred on January 1 2013. Table 6 reports average peak and off-peak prices and firm-level quantities under the existing market structure, and under the counterfactual assuming that each firm's forward quantities are fixed at the pre-transaction level. As illustrated in Table 6, average peak prices increase by approximately $18 (18%), while average off-peak prices change by less than $1.

Table 6: BR3/BR4 Counterfactual Average Output and Market Price

Variable	Status Quo		Counterfactual	
	Peak	Off-Peak	Peak	Off-Peak
QATCO	560	495	573	497
QENMAX	1,263	1,026	1,204	1,022
QCP	1,099	1,040	1,106	1,040
QTA	1,050	982	1,051	982
QTC	1,578	1,481	1,586	1,481
QFRINGE	2,684	2,514	2,708	2,516
SMP	102.77	53.14	121.22	53.60

Notes: All quantity values are in MWs and the SMP is in $/MWh.

To further explore the relationship between the price effect of the PPA expiry and the level of market demand indicated by the comparison of results in peak and off-peak hours, the average price effect of the PPA expiry (in dollars) was computed for the different quartiles of market demand. On average, the price effect of the expiry was $0.66, $7.79, $19.28 and $11.93 in the first, second, third, and fourth quartile hours by demand, strongly indicating that the price effect comes from higher demand hours where the capacity constraints are binding.

Our results highlight the different incentives of ENMAX and ATCO created through their forward positions. In the context of our model, ENMAX's larger forward position drives it to behave more competitively. The transfer to ATCO, a firm with a lower level of forward commitment, results in sizable price effects in periods where demand is high, even though the transfer resulted in limited market concentration effects. These results imply that simply relying on market concentration measures can lead to biased conclusions regarding the impacts of market structure changes such as asset divestitures or the expiration of long-term supply commitments. These findings support the prior critiques of relying on market concentration measures in the electricity industry (Bushnell et al. 1999).

[33]This is suggested further by a comparison of the bidding behavior of BR3 and BR4 in 2013 and 2014, in which there was a sizable change in the offer behavior on these units. However, other explanations for this change in behaviour exist, including the observation that maintenance outages for these units increased after the expiration, further motivating the use of this counterfactual analysis.

7.2 Mergers

Next, we suppose that ATCO and ENMAX were to merge into a single firm (refered to henceforth as AE), and retain all of its existing capacity. We assume that this merger took effect on January 1 2013, and estimate its effect over 2013 and 2014. Initially, we assume that the forward contracted MWs for each firm are fixed. Columns 2 and 3 of Table 7 presents the average price and spot quantities for each firm under the status quo (no merger), while columns 4 and 5 report results under the merger with no divestitures, assuming that the forward contract MWs for each firm are fixed, i.e., the merged firm has a forward quantity equal to the combined forward quantity of the two firms in the absence of the merger.

Table 7: Merger Results: Fixed Forward Quantities

Variable	Status Quo		No Divestiture		Divest to Fringe		Divest to Rivals	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QAE	1,856	1,577	1,832	1,542	1,744	1,515	1,754	1,526
QCP	1,092	1,018	1,098	1,021	1,071	1,006	1,104	1,021
QTA	1,073	993	1,074	994	1,071	988	1,143	1,040
QTC	1,736	1,610	1,743	1,613	1,714	1,598	1,744	1,611
QFRINGE	2,690	2,548	2,695	2,572	2,870	2,652	2,696	2,546
SMP	85.62	50.89	100.13	58.92	34.03	22.34	101.54	52.28

Notes: All quantity values are in MWs and the SMP is in $/MWh.

Our estimates suggest an average price increase from the merger without divestitures of 17% in peak hours and 16% in off-peak hours. Again, we computed the average price effect of the merger by demand quartiles; the average price effect of the merger was $4.04, $7.43, $12.98 and $20.03 in the first, second, third and fourth quartiles, reinforcing that the effect of the merger is primarily in higher demand hours.

To illustrate the impact that divestitures have on merger effects, we suppose that the merged firm is required to divest its coal units BR3, BR4, and BR5. The U.S. Federal Energy Regulatory Commission's (FERC) merger rules would limit a firm to a 20% wholesale market share (FERC, 2012), which would be achieved by the merging firm by divesting 663 MW of capacity; BR3, BR4 and BR5 together have a capacity of 689 MW (MSA, 2013).

We consider two possible divestiture scenarios. Under the first, the units are divested to the competitive fringe. Under the second the units are divested to the three nonmerging large firms, Capital Power, TransAlta and TransCanada. We suppose that the largest Battle River unit is divested to the smallest rival (Capital Power), while the smallest unit is divested to the largest rival (TransCanada). Results with divestitures are reported in columns 5-9 of Table 7. Noteably, the merger with divestiture to the fringe reduces average price to less than half of what it was in the absence of the merger. This finding is consistent with the evidence of Willig (2011), and as we will see in the following section can be attributed to the assumption that the merged firm's forward contracted MWs are unchanged despite losing the divested capacity. In contrast, divesting the Battle River units to the other incumbent firms results in almost no change in price relative to the merger with no divestiture.

8 Counterfactuals with Alternative Forward Contracted Quantities

8.1 Mergers

To consider the possible effect of endogenous forward contracts on the impact of the merger, we suppose that the merging firm reduces its forward contracted MWs by various percentages (5, 10, 20, and 30%). We suppose that the forward contract quantities of nonmerging firms are unchanged.[34]

Table 8: Merger Results: No Divestitures, Varying Forward Positions for Merged Firm

Variable	Status Quo	Fixed MWhs	5%	10%	20%	30%
QAE	1,710	1,680	1,605	1,531	1,387	1,248
QCP	1,053	1,058	1,064	1,071	1,089	1,109
QTA	1,031	1,032	1,033	1,035	1,039	1,043
QTC	1,670	1,675	1,682	1,690	1,709	1,733
QFRINGE	2,616	2,630	2,684	2,734	2,818	2,881
SMP	67.45	78.57	94.21	112.58	158.40	217.20

Notes: All quantity values are in MWs and the SMP is in $/MWh. Columns 4 - 7 represent percentage reductions in AE's forward MWs.

Table 8 presents the average price and firm-level quantities under the status quo and the merger with different forward contracting assumptions. For presentation purposes, results are not separated for peak and off-peak hours. As expected, the estimated price effect of the merger is sharply increasing in the reduction in forward quantity of the merging firms. For example, a reduction in AE's post merger forward MWs of 20% would increase the average price effect of the merger from $11.12 to $90.95. As well, we can see that the spot market quantity of the merging firm falls, but by a lower percentage than forward MWs decrease, meaning that the proportion of a firm's output that is forward contracted decreases.[35]

Table 9: Merger Results: Divestiture to Fringe, Varying Forward Positions for Merged Firm

Variable	Status Quo	Divest (Fixed MWs)	5%	10%	20%	30%
QAE	1,710	1,624	1,556	1,484	1,331	1,177
QCP	1,053	1,037	1,038	1,039	1,044	1,051
QTA	1,031	1,028	1,028	1,028	1,029	1,030
QTC	1,670	1,653	1,654	1,656	1,660	1,668
QFRINGE	2,616	2,756	2,820	2,888	3,025	3,155
SMP	67.45	27.91	30.15	33.55	44.85	62.97

Notes: All quantity values are in MWs and the SMP is in $/MWh. Columns 4 - 7 represent percentage reductions in AE's forward MWs.

Tables 9, 10, and 11 consider adjustments of forward contracted MWs in the presence of different divestitures and adjustments to forward MWs. The first two tables consider the effects of divestiture to

[34] Our range of percentage reductions, and assumption about the nonmerging firms, is guided by Brown and Eckert (2016), in which various Alberta mergers are simulated supposing endogenous forward contracting and simplified linear marginal cost functions. In that analysis, the AE merger resulted in a reduction in the merging firms' forward contracted MW of 25%, while forward contracting quantities for the nonmerging firms varied by approximately 1%.

[35] See Brown and Eckert (2016) for a demonstration of this result in a theoretical model.

the fringe and divestiture to the incumbent rivals, assuming that only AE adjusts its forward MWs. In Table 11, we suppose that AE reduces its forward quantities by 5, 10, 20, and 30%, while the incumbent rivals CP, TA and TC increase their forward MWs by 5%. The latter case is considered to reflect the fact that these firms may be expected to increase their forward positions as their capacities increase.

In Table 9, we observe that divestiture to the fringe uniformly lowers prices, even if the merger reduces AE's forward contracted MWs.[36] In contrast, in Tables 10 and 11 the price effect of the merger with divestiture to the rival incumbents appears to be ambiguous. In cases where the rivals increase their forward MWs by 5% and AE reduces its forward MWs by only 5 or 10% (see Table 11), prices fall or are essentially unchanged after the merger. This ambiguity highlights the importance of understanding how forward positions would be expected to change, and the degree to which they are fixed in the short (typically two year) antitrust horizon.

Table 10: Merger Results: Divestiture to Rival Incumbents, Varying Forward Positions for Merged Firm

Variable	Status Quo	Divest (Fixed MWs)	5%	10%	20%	30%
QAE	1,710	1,635	1,572	1,506	1,368	1,227
QCP	1,053	1,061	1,064	1,070	1,085	1,106
QTA	1,031	1,089	1,091	1,094	1,101	1,111
QTC	1,670	1,674	1,678	1,684	1,699	1,720
QFRINGE	2,616	2,618	2,666	2,714	2,799	2,868
SMP	67.45	75.76	84.62	96.82	131.86	180.09

Notes: All quantity values are in MWs and the SMP is in $/MWh. Columns 4 - 7 represent percentage reductions in AE's forward MWs.

Table 11: Merger Results: Divestiture to Rival Incumbents, Varying Forward Positions for Merged Firm, Rival Forward MWs Increase 5%

Variable	Status Quo	Divest (Fixed MWs)	5%	10%	20%	30%
QAE	1,710	1,635	1,565	1,496	1,353	1,207
QCP	1,053	1,061	1,105	1,109	1,120	1,137
QTA	1,031	1,089	1,120	1,121	1,126	1,132
QTC	1,670	1,674	1,749	1,753	1,765	1,782
QFRINGE	2,616	2,618	2,545	2,600	2,704	2,793
SMP	67.45	75.76	59.67	68.83	95.88	134.62

Notes: All quantity values are in MWs and the SMP is in $/MWh. Columns 4 - 7 represent percentage reductions in AE's forward MWs.

To explore further the impact of forward market assumptions on the effect of the merger, Tables 12 and 13 present the average post-merger prices for a specific month (October 2013) under different asset divestiture scenarios. This month was chosen as the month whose average observed price is closest to the average over our sample. Table 12 shows post-merger prices assuming that BR3, BR4 and BR5 are divested to the major rivals. Prices are shown for various forward MW reductions of the merged firm ranging from 0% to 25%, and for forward MW *increases* for the non-merging major firms from 0% to 10%.

[36] Further reductions in AE's forward quantities can result in the merger with divestiture increasing price. For example, reducing the merged firm's forward MWs by 40%, which is less than the 50% assumed in Wolak (2011), results in an average price of $89.51.

Table 12: Average Post-Merger Prices with Divestiture to Major Rivals (October 2013)

% Δ Rival Forward Quantity	-25	-20	-15	-10	-5	0
10	99.25	80.87	66.18	54.18	44.59	36.82
8	115.52	94.95	77.44	63.47	51.97	42.84
6	133.76	111.12	91.05	74.39	61.04	50.02
4	152.47	128.76	107.16	87.76	71.77	58.85
2	173.11	147.99	124.83	103.76	84.96	69.53
0	194.85	168.79	144.18	121.5	100.86	82.63

% Δ in Forward Quantities of Merging Firms

$\Delta P > 10\%$

$-10\% \leq \Delta P \leq 10\%$

$\Delta P < -10\%$

Table 13: Average Post-Merger Prices with Divestiture to Fringe (October 2013)

% Δ Rival Forward Quantity	-40	-35	-30	-25	-20	-15
2	82.67	67.88	55.92	46.53	39.08	33.47
0	96.26	78.8	64.82	53.44	44.65	37.62
-2	111.7	91.77	75.25	61.98	51.19	42.9
-4	128.51	106.92	87.56	71.93	59.33	49.17
-6	146.77	123.52	102.42	83.87	69.01	56.98
-8	166.22	141.6	118.94	98.36	80.67	66.47

% Δ in Forward Quantities of Merging Firms

$\Delta P > 10\%$

$-10\% \leq \Delta P \leq 10\%$

$\Delta P < -10\%$

We suppose that the merging firm decreases its forward contracting in equilibrium; for non-merging firms, this effect is assumed to be offset by the increase in capacity, leading to an increase in forward MWs. As shown in Table 12, the merger with divestiture to fringe can yield both price increases and decreases. The dark region corresponds to price increases of more than 10%, while the white region identifies price decreases of more than 10%. As expected, higher post-merger prices correspond to a greater decrease in the forward MWs of the merging firms and a smaller increase for the non-merging rivals. Note however that price decreases only occur in scenarios in which total forward-traded MWs increase post-merger; increases in post-merger prices occur both under increases and decrease of total forward-traded MWs.

A similar story emerges from Table 13, which supposes that the units are divested to the fringe, and considers forward MW reductions of the merged firm ranging from 15% to 40%, and for forward MW changes for the non-merging major firms from -8% to 2%. Mergers followed by relatively large decreases in forward MWs tend to result in increases in price, while prices tend to fall when the forward MWs change is limited. Together, these results emphasize the sensitivity of predicted merger price effects to assumptions regarding the response of forward positions. Importantly, Tables 12 and 13 highlight the role of not only the forward position of the merging firms, but also of the non-merging firms, which would be expected to adjust forward quantities in equilibrium in a setting with endogenous forward contracting.

8.2 Expiry of PPAs: BR3 and BR4

Finally, we consider how changes to forward positions (in MWs) affect the implications of the early expiry of the BR3 and BR4 PPAs. In the previous section we assumed that the forward contracted MWs of ATCO and ENMAX would be unchanged, despite the resulting increase and decrease in their offer control capacity. However, it is reasonable to expect that as ATCO (ENMAX)'s capacity increases (decreases), its forward MWs would increase (decrease). In this subsection we consider two alternatives. In the first, each of these firms changes its forward contracted MWs in proportion to the associated change in its capacity; this results in a 21% increase and 16% decrease in the forward quantities of ATCO and ENMAX respectively. As well, we consider an intermediate case in which ATCO's forward quantity is increased by 10.5% and ENMAX's falls by 8%. Throughout, we keep the forward quantities of the other firms unchanged.

The results are shown in Table 14. Results are computed for 2013 only and are for peak and off-peak hours combined. Our assumed adjustments to forward positions enhance the price increase from the merger. For example, adjusting forward positions by 10.5% and 8% results in a 16.2% increase in average prices, compared to an increase of 11.8% holding forward MWs constant.

Table 14: Expiry of BR3 and BR4 PPAS Under Different Forward Positions for ATCO and ENMAX

Variable	Status Quo	Fixed MWs	21 and 16	10.5 and 8
QATCO	526	533	614	571
QENMAX	1,139	1,109	964	1,040
QCP	1,068	1,071	1,077	1,075
QTA	1,014	1,015	1,016	1,015
QTC	1,527	1,531	1,535	1,532
QFRINGE	2,595	2,607	2,657	2,632
SMP	76.80	85.83	94.98	89.25

Notes: All quantity values are in MWs and the SMP is in $/MWh. Columns 4 (5) present results assuming ATCO's and ENMAX's forward MWs increase and decrease by 21 (10.5) and 16 (8) % respectively.

8.3 Sensitivity Analysis: Import Supply Elasticity

A remaining concern is that the sensitivity of the price effect of a merger to forward market assumptions may be driven by the high degree of inelasticity of our estimated residual demand curve, coming from our estimates of the import supply function.[37] To explore this possibility, we recalibrated the forward market MWs for October 2013, varying the coefficient on price in the import supply function. We then re-simulate the effects of the merger under different foward market and divestiture assumptions.

Table 15 reports the percentage price effect of the AE merger, under our different assumptions regarding divestitures and adjustments to forward positions, increasing the estimated import price sensitivity coefficients by 200% and 300%. In general, as expected, increasing the sensitivity of imports to price reduces predicted prices both before and after the merger. The average pre-merger price for October 2013 falls from $72.6 under an import parameter of 0.437 (which represents the sum of the price coefficients across both neighboring provinces) to $49.52 and $42.05 when that parameter is doubled and tripled. However, while somewhat muted, the role of forward positions in the effect of a merger persists. For example, Table 15 indicates that under the estimated import parameter, a merger with no divestiture and fixed forward MWs would increase price by 63.28%, but that this increase would fall to 44% with the import price sensitivity doubled, and to 34% when it is tripled. On the other hand, A merger with

[37]Note however that the degree of inelasticity of our residual demand curve is consistent with results for other U.S. markets with the exception of California, which exhibits a much higher reliance on imports. See for example Bushnell et al. (2008).

divestiture to the large rivals, assuming AE reduces forward MWs by 10% and other rivals increase forward MWs by 5% would increase average prices by 11.25% under the estimated important parameter, but only by 9.63% or 8.80% when that parameter is doubled or tripled.

As Table 15 illustrates, even with a tripling of the import price sensitivity, the effect of forward market assumptions on the price effect of a merger can be dramatic. With a 30% increase, for example, a merger with divestiture to large rivals results in a 3.3% decrease in price when rivals increase forward MWs by 5% and AE decreases forward MWs by 5%, but a 69% *increase* when AE's foward MWs are decreased by 30%. As a result, even with greater residual demand elasticity, understanding forward markets and how they would respond to a merger or market structure change is crucial in predicting the price effects of such transactions.

Table 15: Percentage Price Effect of Merger Under Different Divestiture and Forward MWs Scenarios: Robustness to Import Price Coefficient, October 2013

Scenario		Estimated	Doubled	Tripled
No divesture	Fixed Forward MWs	63	44	34
	AE reduced 5%	95	67	51
	AE reduced 10%	131	92	70
	AE reduced 20%	208	147	113
	AE reduced 30%	291	208	160
Divestiture to Fringe	Fixed Forward MWs	-65	-50	-43
	AE reduced 5%	-61	-46	-39
	AE reduced 10%	-55	-41	-34
	AE reduced 20%	-39	-27	-22
	AE reduced 30%	-11	-7	-5
Divestiture to Rivals	Fixed Forward MWs	14	11	10
	AE reduced 5%	39	28	22
	AE reduced 10%	67	47	37
	AE reduced 20%	132	94	71
	AE reduced 30%	206	146	111
Rivals increase Forward MWs by 5%	AE reduced 5%	-9	-5	-3
	AE reduced 10%	11	9	8
	AE reduced 20%	65	45	35
	AE reduced 30%	131	91	69

9 Conclusion

In this paper we develop a Cournot model of Alberta's wholesale electricity market that accounts for firms' forward contracts. We use data from 2013 and 2014 to estimate residual demand, the marginal cost functions, and to calibrate the existing forward positions of the large dominant firms. We use this model to simulate the effects of a Purchase Power Arrangement expiration and hypothetical merger of two dominant firms. Our results demonstrate the sensitivity of merger simulations in electricity markets to assumptions regarding forward positions and how they would respond to market structure changes. Ignoring firms' forward commitments can lead antitrust authorities to biased conclusions regarding the impacts of proposed mergers or market structure changes.

We demonstrate that merger effects are magnified if the merged firm reduces its forward contract position in the post-merger equilibrium. Further, our analysis illustrates the impacts of mergers with asset divestitures that are often used to alleviate market power concerns in antitrust cases. As anticipated, the market power effects of mergers are reduced when the merging firms' generation assets are divested to the competitive fringe, compared to being divested to large incumbents who are net-sellers into the wholesale market.[38] Regardless of the nature of asset divestiture, the merger effects are magnified when the merging firm decreases its forward contract quantities in the post-merger equilibrium.

We illustrate that a partial merger that transfers capacity from a firm with a large forward contract position (e.g., due to vertical retail commitments), to a firm with a limited forward position can result in large price effects even though there are limited changes in standard concentration measures. These results highlight the importance of accounting for the nature of firms forward commitments. Further, this emphasizes the issues associated with the use of concentration measures when estimating the wholesale market impacts of proposed mergers or market structure changes in the electricity industry.

The results of our analysis also illustrates that the price effects of mergers and market structure changes have the potential to be substantially lower in regions where firms' forward contracts are held constant either due to regulatory restrictions or long-term retail commitments compared to a setting with endogenous forward contracts. These results emphasize the importance of forming a careful understanding of forward markets when simulating merger effects, and of systematic robustness checks regarding assumed changes to forward positions when studying wholesale market merger effects in antitrust cases.

Our paper indicates several directions for future research. The impact of mergers and market structure changes on firms' incentives to forward contract in electricity markets warrants further investigation. Existing theory of endogenous forward contracting and subsequent spot market competition makes numerous restrictive assumptions that limits its applicability in antitrust merger analyses. In particular, the existing literature either assumes that firms forward contract solely for strategic or risk-hedging incentives. To our knowledge, only Van Eijkel and Moraga-Gonzales (2013) consider the strategic and risk-hedging incentives for forward contracting simultaneously. In addition, due to computational complexity the existing literature of endogenous forward contracting in electricity markets often ignores important aspects of firms' cost structures such as capacity constraints and nonlinearities. Extending this literature to a point where it can be used in electricity market merger simulations is a priority of future research.

Our results demonstrate that not all asset divestitures are equal. Whether divestiture of a particular asset will offset the price effects of a merger depends on the firm(s) to whom the units are divested, the existing forward commitments of the firm(s) acquiring the asset(s), and the response of firms' forward positions in the post-merger equilibrium. Future work will incorporate divestitures into a model with endogenous forward contracting a la Bushnell (2007) and Brown and Eckert (2016).

[38]This result will not necessarily hold if assets are divested to a large dominant firm who has large amount of forward commitments. However, if the dominant firm is able to adjust its forward contracts after acquiring the assets, the asset divestiture to a dominant firm may result in more market power compared to asset divestiture to the competitive fringe.

Appendix

A Marginal Cost Functions

We used data on unit-specific heat rates made available from the MSA (2012), Alberta Utility Commission, and the AESO. In 2014 and 2015 in Alberta, the Specified Gas Emitter Regulation requires fossil-fuel generators to pay a fee (equivalent to \$15/tCO2) on emissions or purchase offsets (SGER, 2007). Pfeifenberger and Spees (2011) estimate this results in a compliance cost of \$1.80/tCO2 emissions which translates to a \$1.35/MWh and \$0.79/MWh for natural gas combustion turbines and combined cycle units, respectively. From the SGER (2007) regulation, cogeneration units receive an environmental credit because they are highly efficient. The estimated average environmental credit for cogeneration units translates to approximately \$1.28/MWh (AESRD, 2009). This is applied to the marginal cost estimate of non-must-run cogeneration units. We use data on technology specific variable O&M rates made available from the U.S. Energy Information Administration (EIA, 2013), adjusted from USD to CAD using the average 2014 and 2015 Bank of Canada exchange rates. For coal units, we estimate the unit-specific marginal cost use the Monte Carlo simulation technique detailed in Brown and Olmstead (2016).

B Estimation of ENMAX Retail Sales

Monthly data on retail electricity volumes and site counts, by customer class (residential, farm, small commercial and industrial and large commercial and industrial) and by region are given on the MSA website. These data also divide volumes and site counts in each customer class according to whether the electricity was purchased through a default contract (RRO for all classes except large industrial and commercial customers) or through a competitive contract. While ENMAX's sales through RRO or default contracts are precisely identified, these data do not separate sales through competitive contracts by firm. Market shares by firm for each region and customer class from January 2012 to March 2015 are available in the MSA (2015). Market shares are by site counts for all classes except large industrial and commercial, for which market shares are reported both by site count and volume. These market shares are used to approximate ENMAX's share of retail sales on competitive contracts.

To divide residential, farm, small commercial and small residential sales according to peak and off-peak hours, we employ data from ENMAX's monthly RRO energy charge filings, available through the Alberta Utilities Commission website, which report the monthly MWs procured under flat and peak forward contracts, based on ENMAX's internal forecasts of peak and off-peak demand. We assume that actual retail sales for both default and competitive contracts can be divided into peak and off-peak hours according to these numbers. We suppose that all retail sales to farm, small commercial and residential customers are through fixed-price contracts.

Over 2013-2014, ENMAX's retail sales per hour to residential, small commercial and small industrial customers come to 838 MWhs (561.2 MWhs) in peak (off-peak) hours. While ENMAX's large commercial and industrial sales are not easily broken down into peak and off-peak hours, the MSA data yield an average hourly sales to large commercial and industrial customers of 1390.3 MWhs. However, it should be noted that more customers in this category are expected to purchase electricity through wholesale price pass-through contracts.

To illustrate the fit of our estimated forward positions from the Cournot model with ENMAX's fixed-price commitments, Figure A1 plots ENMAX's estimated forward MWs using our Cournot model, along with retail sales to farm, small commercial and residential customers plus 30% of large industrial and commercial sales. In general, while the latter exhibits less fluctuation, the longer term movements and level of the two series are similar, providing further support for our forward market positions.

Figure A1: ENMAX Estimated Forward Position and Retail Commitment, Peak Hours Including 30% of Large Industrial/Commercial

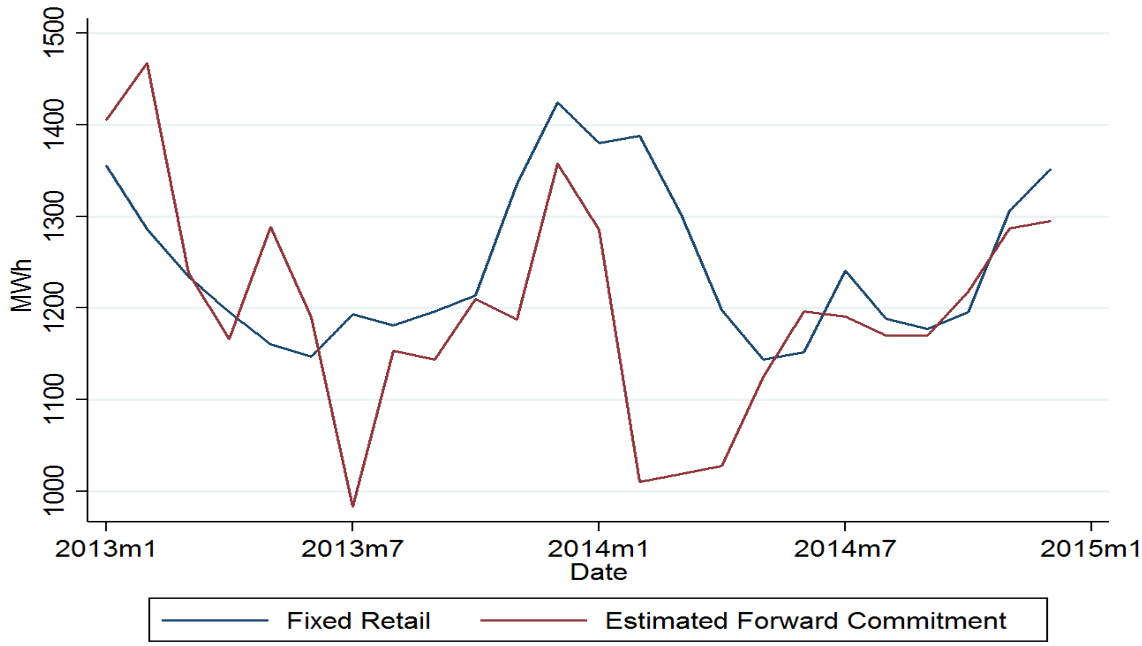


Table A1: Hourly Import Supply Function IV Estimation

	Saskatchewan		British Columbia	
	First Stage	Second Stage	First Stage	Second Stage
	p_t	$Q^{IM}_{SK,t}$	p_t	$Q^{IM}_{BC,t}$
p_t	—	0.0639***	—	0.373***
		(0.019)		(0.073)
HDD_j	1.66	-0.372	-1.88	20.65***
	(1.07)	(0.37)	(2.33)	(2.636)
HDD_j^2	-0.018	0.006	0.101	-0.53***
	(0.017)	(0.006)	(0.08)	(0.094)
CDD_j	-5.398	-0.363	-30.06***	33.17***
	(6.999)	(1.358)	(10.10)	(8.32)
CDD_j^2	1.225	-0.047**	4.86**	-2.61
	(0.936)	(0.017)	(2.22)	(1.679)
ImportCap	-0.234***	0.149***	-0.127***	0.30***
	(0.07)	(0.025)	(0.020)	(0.023)
Weekday	20.61***	2.988	19.46***	49.31***
	(4.526)	(2.16)	(4.51)	(7.036)
Holiday	4.674	4.123	3.029	-62.81***
	(20.1)	(7.29)	(18.18)	(19.96)
Q_{WIND}	-0.071***		-0.075***	
	(0.009)		(0.008)	
HDD_{Edm}	0.008	—	1.124	—
	(1.235)		(1.318)	
$\text{HDD}^2{}_{Edm}$	-0.011	—	-0.0291	—
	(0.026)		(0.028)	
HDD_{Cal}	-7.666***	—	-6.58***	—
	(1.451)		(1.42)	
$\text{HDD}^2{}_{Cal}$	0.175***	—	0.149***	—
	(0.036)		(0.035)	
CDD_{Edm}	-7.043	—	-1.94	—
	(8.658)		(8.61)	
$\text{CDD}^2{}_{Edm}$	3.921***	—	3.739***	—
	(1.314)		(1.21)	
CDD_{Cal}	-9.289	—	-8.13	—
	(8.522)		(7.976)	
$\text{CDD}^2{}_{Cal}$	2.533**	—	2.65***	—
	(1.027)		(0.987)	
Constant	162.34***	12.23***	206.72***	-292.02***
	(26.88)	(2.949)	(27.76)	(28.96)
R^2	0.40	—	0.41	—
Kleibergen-Paap Wald F-Stat	40.19***	—	54.82***	—
Sample Size	17,520	17,520	17,520	17,520
Hour-Month-Year Covariates	Y	Y	Y	Y

Notes: The regressions are estimated using IV with Heteroskedasatic and Autocorrelation (HAC) robust standard errors (in parentheses) with 24 lags. The temperature variables contain heating degree days (HDD) and cooling degree days (CDD) for two cities in Alberta (Edmonton (Edm) and Calgary (Cal)), Vancouver in BC (denoted BC), and Saskatoon (denoted SK). HHD_j and CDD_j denotes the temperature variables for the province whose import function is being estimated (i.e., $j \in \{BC, SK\}$). ***, ** and * indicate statistically significant coefficients at the 1%, 5%, and 10% percent levels, respectively.

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