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Strategic Interaction Between Wholesale and Ancillary Service Markets

David P. Brown
University of Alberta

Andrew Eckert
University of Alberta

Douglas Silveira
University of Alberta

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David P. Brown[†] Andrew Eckert[†] Douglas Silveira[†]

Abstract

In electricity markets, system reliability requires the instantaneous balancing of supply and demand. In addition to the wholesale electricity market, the procurement of various ancillary services is vital in achieving this objective. An important design feature is whether ancillary service markets clear simultaneously or sequential with wholesale markets. We propose a model to study the strategic implications of simultaneous versus sequential timing when firms compete in the ancillary services and wholesale electricity markets. Considering the case where ancillary services markets clear before wholesale markets, we demonstrate that when firms face increasing marginal cost curves, a strategic incentive to reduce ancillary services output and, consequently, lower their marginal costs in the wholesale market arises. We employ data from Alberta's electricity markets to demonstrate the quantitative implications of our findings. Our numerical results show that the strategic commitment effect has a small impact on wholesale market outcomes but a large impact on the equilibrium in the ancillary services market, elevating the market-clearing price.

Keywords: Ancillary services, electricity, market power, strategic commitment
JEL Classification: L13, L50, L94, Q40

[†] *Department of Economics, University of Alberta, Edmonton, Alberta Canada*

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1 Introduction

Electricity markets require careful coordination of diverse resources to meet uncertain demand. In restructured markets, suppliers are compensated for providing both electricity and short-term reliability. This has led to the development of two key markets: a wholesale market to compensate for energy provision and an ancillary services market for reliability products. In this paper, we analyze a linkage between these markets that can serve as a strategic commitment mechanism when firms have the ability to exercise market power.

There are a multitude of ancillary service (AS) markets, with their precise details varying by jurisdiction. Common AS products include frequency regulation products that balance instantaneous changes in electricity supply and demand with time-scales ranging from seconds to minutes, various contingency reserves that manage larger changes (e.g., due to the loss of a generator), and increasingly ramping products that manage systematic large changes in market conditions (e.g., sunset and reduced solar supply) (Fournié et al. 2016; Pollitt and Anaya 2020; Van den Bergh and Delarue 2020). The dramatic growth of renewable energy resources and their associated variable electricity output has increased the importance of AS markets in ensuring a reliable supply of electricity (González et al. 2014).

A central feature of AS markets is the timing of market-clearing in relation to wholesale electricity markets. Broadly speaking, there are two categories of market-clearing. First, is joint clearing – based on a co-optimization approach – in which wholesale and AS markets clear simultaneously.[1] This timing is adopted in a number of US markets (e.g., PJM, CAISO, ERCOT, MISO, and NYISO).[2] Second is sequential clearing, under which the wholesale and AS markets clear sequentially with the AS market typically clearing first.[3] Except for a few countries, the EU provides numerous examples where AS and wholesale markets clear sequentially (Kumar and Singh 2021).

In this paper, we analyze the strategic implications of simultaneous versus sequential market-clearing in wholesale-AS market competition. The presence of market power in wholesale markets is well documented and analyzed (Borenstein, Bushnell, and Wolak 2002; Bushnell, Mansur, and Saravia 2008; Brown and Olmstead 2017). Concerns over market power in AS markets have also been documented (González et al. 2014; Pollitt and Anaya 2020), but its implications have received considerably less attention.

We develop a model of wholesale and AS market competition to understand how changes

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1. Read (2010) points out that co-optimization reduces costs associated with the provision of reserves and generates pricing incentives in wholesale and AS markets. Baldick (2017) states that co-optimization contributes to market efficiency and price formation once it allows the reserve prices to reflect the actual opportunity cost for providing ancillary service products. Regarding the policy implications, Kumar and Singh (2021) argue that co-optimization improves resource utilization and leads to a lower procurement cost. From a financial-engineering perspective, Smeers, Martin, and Aguado (2021) highlights that co-optimization reduces costs and inhibits arbitrages between wholesale and ancillary services markets.

2. See Zhou, Levin, and Conzelmann (2016) for a survey.

3. There are also jurisdictions such as Italy where AS products are procured after energy. In this setting, generators estimate the value of the AS products when they make their offers in the wholesale market. Oggioni and Lanfranconi (2015) argues that this market framework can increase costs and contribute to the reduction of system reliability.

in market timing can impact equilibrium market outcomes. We assume that generators compete via Cournot competition in wholesale and ancillary service markets. Importantly, the provision of AS output impacts a generator's cost of providing wholesale output because it precludes the use of a portion (or all) of a generation unit's available capacity in the wholesale market. Consequently, this creates a linkage between the AS and wholesale market output choices impacting strategic behavior and equilibrium outcomes in both markets.

We demonstrate that sequential market-clearing can introduce an important strategic commitment effect when choosing AS output. When a firm supplies AS market output, it increases its cost of providing output in the subsequent wholesale market, in turn committing the firm to competing less aggressively in the wholesale market. The presence of this strategic effect causes the oligopolists to produce less output in the AS market in equilibrium in the sequential timing setting. We demonstrate that the strategic effect causes AS market prices to increase and wholesale prices to decrease when the markets clear sequentially compared to when they clear simultaneously.

We employ data from Alberta's wholesale and ancillary service market to demonstrate the quantitative implications of our findings. We use this empirical setting to define our model parameters. Further, we relax a number of assumptions employed in our theoretical model, including allowing for more than two strategic firms, the presence of must-run generation (e.g., wind) and import supply, and the presence of a competitive fringe in both the wholesale and AS markets.

Our numerical results demonstrate that the presence of the strategic commitment effect has a small impact on wholesale market outcomes, but a large impact on the equilibrium in the AS market, elevating market-clearing AS prices. The large effect in the AS market is driven by the fact that the market is highly concentrated and fringe supply is highly inelastic. As a result, small changes in output by the large firms in the sequential setting can have a sizable impact on AS market outcomes. Alternatively, the wholesale market is larger in magnitude and has a more elastic fringe supply function. This induces smaller differences in equilibrium outcomes in the sequential versus simultaneous market-clearing cases.

When looking across both markets, we find that total procurement costs only increase by a small margin in the sequential move setting. While the AS prices increase considerably, the AS market is relatively small compared to the wholesale market. Consequently, the small price reductions in the wholesale market counteract the large increases in the AS price. This demonstrates that looking only at the AS market outcomes in isolation may lead to conclusions that the elevated market power results in a considerable reduction in consumer surplus. However, this overlooks a key component of the overall market outcome, the impact on wholesale market competition. Our findings stress the importance of considering the strategic linkages between AS and wholesale markets, and the overall impact on market outcomes and procurement costs across both markets.

Our analysis makes several contributions to the literature. First, there is a large engineering literature that considers the technical aspects associated with supplying and procuring AS products (e.g., Hirst and Kirby (1998), Just and Weber (2008), Papavasiliou and Smeers (2017), and Yu and Foggo (2017)). A number of articles document the engineering and technical trade-offs associated with sequential and simultaneous market-clearing (AESO 2018; Zarnikau et al. 2019; Pandžić et al. 2020). To the best of our knowledge, our article is the first to document the potential role of strategic behavior in impacting market outcomes under different market-clearing timing assumptions.

Second, there is a growing empirical economics literature that analyzes the interaction of wholesale and ancillary service markets. These articles consider a number of topics ranging from firm learning behavior in newly created AS markets (Doraszelski, Lewis, and Pakes 2018), the introduction of financial "virtual bidding" and its impact on fuel and AS costs (Jha and Wolak 2020), and the impact of an increase in AS product procurement on generation capacity investment and production decisions (Buchsbaum et al. 2021). Unlike our analysis, these articles abstract away from considering strategic behavior and AS market timing.

Third, the presence of market power execution has been documented extensively in wholesale electricity markets (Borenstein, Bushnell, and Wolak 2002; Reguant 2014; Brown and Olmstead 2017). The impact of sequential markets has primarily been considered in the electricity sector through the interaction of forward contracting that occurs prior to wholesale market-clearing. Allaz and Vila (1993) documents the potential strategic commitment effects associated with signing fixed-priced forward contracts prior to wholesale market competition. The authors find that strategic forward contracting commits firms to competing more aggressively in subsequent wholesale markets.[4] There is a large empirical literature demonstrating that forward contracting induces more competitive wholesale market outcomes (e.g., Mansur (2007), Wolak (2007), and Bushnell, Mansur, and Saravia (2008)). While there is a strategic commitment effect in this setting, this literature considers a different market interaction and strategic mechanism than the one considered in our analysis.

Fourth, there is an industrial organization literature that analyzes the role and impacts of strategic commitment in concentrated markets with representative contributions by Fudenberg and Tirole (1984), Bulow, Geanakoplos, and Klemperer (1985), and Chen and Ross (2007). This literature documents how the nature of market competition and timing can affect firms' marginal costs and, consequently, impact the effects of strategic commitment. Our analysis can be viewed as a unique application of the strategic commitment effect in the setting with multi-market AS and wholesale electricity market competition.

Our analysis proceeds as follows. Section 2 describes our duopoly model of AS and wholesale market competition, and presents the equilibrium model outcomes. Section 3 provides the numerical analysis framework and empirical findings. Section 4 concludes.

2 Theoretical Framework

In this section, we present a simple duopoly model of AS and wholesale markets to illustrate the strategic incentives firms face in choosing AS market output and to highlight the potential effect of those incentives on market outcomes. In the subsequent empirical analysis, we will

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[4] There is a sizable literature that extends the Allaz and Vila (1993) analysis to consider a number of additional features (e.g., Mahenc and Salanié (2004), Holmberg (2011), Ito and Reguant (2016), and Van Eijkel, Kuper, and Moraga-González (2016)).

extend this model to include more than two firms and calibrate it to the case of Alberta. It is important to acknowledge that our analysis abstracts from various technical aspects associated with the provision of AS products which have received considerable attention in the literature. This allows us to achieve our primary objective which is to better understand the strategic implications of AS-wholesale market competition.

2.1 Model

There are two firms (1 and 2) who generate electricity, which is a homogeneous product. The firms compete to supply electricity in two markets: the wholesale electricity market and the AS market. Denote firm i's AS output as $x_i \geq 0$ and its wholesale market output $q_i \geq 0$ for $i = 1, 2$. In the AS market, firms face the inverse demand function $P^{AS}(x_1,\, x_2) = A - B\,(x_1 + x_2)$, where A and B are positive constants. Similarly, in the wholesale market, the inverse demand function is given by $P(q_1, q_2) = a - b\,(q_1 + q_2)$, where a and b are positive constants. Firms choose quantities in both markets; that is, they are Cournot competitors.[5]

Electricity generators typically own a portfolio of generating assets with multiple technologies and different marginal costs, so that their firm-level marginal cost curves are increasing. As a result, increased output in one market (either AS or wholesale) will move the firm up along its marginal cost curve, increasing the marginal cost of supplying the other market. To capture this, we suppose that generating firms have quadratic cost functions (with linear marginal costs). In particular, the cost function of firm i is given by:

$$C_i(q_i, x_i) = \kappa\,(q_i + \eta x_i) + \frac{1}{2}\,\gamma\,(q_i + \eta x_i)^2, \;\; \text{for} \;\; i = 1, 2 \tag{1}$$

where κ and γ are positive constants.

Output sold in an AS market is a commitment to generate electricity as needed in the event of outages and market imbalances. A complicating factor, however, is that for certain AS products, supplying a certain amount of AS from a generator requires the firm to not offer that capacity into the wholesale market; as a consequence, supplying AS can make the associated capacity ineligible for the wholesale market, and shift up the firm's wholesale marginal cost regardless of whether the AS capacity is actually called upon to generate. To capture these features of AS markets in a tractable way, we apply a weight $\eta \in (0, 1]$ to AS output in the cost function. Greater values of η may reflect that it is more likely the AS electricity will be supplied; η may also be larger if the generation capacity intended for AS production must be made unavailable in the wholesale market regardless of whether it is ultimately called upon in the AS market.[6] Greater values of η imply that increases in AS

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[5] An alternative modeling approach would be a Supply Function Equilibria (SFE) framework (Klemperer and Meyer 1989). We adopt a Cournot framework as a simple setting to highlight the main strategic incentives of interest. It has been argued (e.g., Borenstein and Bushnell 1999; Baldick, Grant, and Kahn 2004) that the SFE approach is most valuable in settings where firms submit offers that apply for an extended period of time during which demand experiences important variation; in Alberta (the setting of our numerical analysis), offers apply to a single hour, and can be adjusted up to two hours in advance.

[6] More details on the functioning of the AS market and likely values of η in our example of Alberta are given in Section 3.2.2.

output have a greater effect on marginal cost in the wholesale market.

Firms earn revenues from their AS sales as well as their wholesale market output. Firm i's profits, $i = 1, 2$, are specified as follows:

$$\begin{aligned}\pi_i(q_i, q_j, x_i, x_j) &= P(q_i, q_j)\, q_i + P^{AS}(x_i,\, x_j)\, x_i - C_i(q_i, x_i)\\ &= (a - bq_i - bq_j)\, q_i + (A - Bx_i - Bx_j)\, x_i - \kappa\,(q_i + \eta x_i) - \frac{1}{2}\,\gamma\,(q_i + \eta x_i)^2. \quad (2)\end{aligned}$$

We consider two variations in model timing, designed to reflect different market design regimes used in practice. First, we assume that the firms choose their outputs in both markets simultaneously, which corresponds to regimes employing a joint-clearing co-optimization approach. For this timing, we characterize the pure strategy Nash Equilibrium (PSNE). We then consider the case in which firms choose AS quantities simultaneously first, and then choose wholesale market quantities simultaneously in a second stage. This case corresponds to market design regimes in which AS markets clear before wholesale markets. We solve this case via backwards induction to characterize the subgame perfect Nash Equilibrium (SPNE). We then compare outcomes from the two timing assumptions. Throughout our analysis we will assume interior solutions. In our empirical application, we will allow for corner solutions.

2.2 Simultaneous Market-Clearing

We first consider a static game, in which firms simultaneously choose both their AS and wholesale market outputs. Firm i chooses q_i and x_i to maximize profits, holding q_j and x_j constant. Using the profit function specified in (2) yields the following first order conditions:

$$\frac{\partial \pi_i}{\partial q_i} = a - 2b\, q_i - b\, q_j - \kappa - \gamma\,(\eta\, x_i + q_i) = 0 \quad (3)$$

$$\frac{\partial \pi_i}{\partial x_i} = A - 2B\, x_i - B\, x_j - \eta\kappa - \gamma\,\eta\,(\eta\, x_i + q_i) = 0. \quad (4)$$

Note that the first order conditions for x_i and q_i are linked through marginal costs; the greater is x_i, the greater the marginal cost of q_i, and vice versa. The magnitude of this connection depends on the magnitudes of γ and η. Greater values of γ correspond to a more steeply-sloped marginal cost curve, while increased η results from an increase in the likelihood that the generation required to produce the AS output will be unavailable in the spot market.

Solving the four first order conditions yields a symmetric Nash equilibrium with the following AS and wholesale quantities for each firm:

$$x_{simultaneous} = \frac{(3b + \gamma)\, A - 3b\,\eta\,\kappa - a\,\eta\,\gamma}{9\,B\,b + \gamma\,(3B + 3b\,\eta^2)} \quad (5)$$

$$q_{simultaneous} = \frac{(3B + \eta^2\,\gamma)\, a - 3B\,\kappa - A\,\eta\,\gamma}{9\,B\,b + \gamma\,(3B + 3b\,\eta^2)}. \quad (6)$$

In both equilibrium quantities, the first two terms in the numerator reflect the vertical demand intercept in the associated market and the constant component of marginal cost, respectively; indeed, in the case where $\eta = 1$ and $\gamma = 0$, these solutions collapse to the standard Cournot equilibria with linear demand and constant marginal cost. The third term in the numerator of each equilibrium expression reflects the fact that the marginal cost of supplying output in one market (either wholesale or AS) is increasing in the amount supplied in the other market, which in turn is increasing in the demand intercept in the other market. For example, as a, the demand intercept in the wholesale market, increases, the firm's output in the wholesale market will increase. This will raise the marginal cost of supplying output into the AS market, reducing the firm's quantity in that market.

2.3 Sequential Market-Clearing

Next, we suppose that the AS market takes place before the wholesale market, so that AS quantities are chosen before wholesale market quantities. In particular, suppose that x_1 and x_2 are simultaneously chosen in stage 1. The firms observe the AS quantities chosen in stage 1, and then choose q_1 and q_2 simultaneously in stage 2. This change in timing introduces the possibility that firms will choose their AS market outputs strategically in order to influence wholesale market outcomes.

We look for SPNE using backward induction, by first solving for the Nash equilibrium in the wholesale market for specific values of q_1 and q_2, and then moving up to the first stage to consider the choice of these AS outputs, taking into account how they affect wholesale market outcomes. Conditional on x_1 and x_2, the second stage first order condition for firm i is the same as that specified in the simultaneous case in (3). We use (3) to solve for the second stage Nash equilibrium in the wholesale market as a function of x_1 and x_2:

$$q_1(x_1, x_2) = \frac{(a-\kappa)(\gamma+b) + b\,\eta\,\gamma\,x_2 - \eta\,\gamma\,x_1\,(2b+\gamma)}{(3b+\gamma)(b+\gamma)} \tag{7}$$

$$q_2(x_1, x_2) = \frac{(a-\kappa)(\gamma+b) + b\,\eta\,\gamma\,x_1 - \eta\,\gamma\,x_2\,(2b+\gamma)}{(3b+\gamma)(b+\gamma)}. \tag{8}$$

We then consider the first stage choices of x_1 and x_2, taking into account their effect on wholesale market quantities. Using (2) and given the second stage solutions $q_1(x_1, x_2)$ and $q_2(x_1, x_2)$ in (7) and (8), firm i's first stage profit function becomes:

$$\begin{aligned}\pi_i(x_i, x_j, q_i(x_i, x_j), q_j(x_i, x_j)) &= [a - b\,(q_i(x_i, x_j) + q_j(x_i, x_j))]\,q_i(x_i, x_j) \\ &+ [A - B\,(x_i + x_j)]\,x_i - \kappa\,(\eta\,x_i + q_i(x_i, x_j)) - \frac{1}{2}\gamma\,(\eta\,x_i + q_i(x_i, x_j))^2. \end{aligned} \tag{9}$$

Using (9) and recognizing that in the second stage q_i will be chosen to set $\frac{\partial \pi_i}{\partial q_i} = 0$, the first-stage first order condition for firm i can be written as:

$$\frac{\partial \pi_i}{\partial x_i} + \frac{\partial \pi_i}{\partial q_j}\frac{\partial q_j(x_i, x_j)}{\partial x_i} = 0. \tag{10}$$

Using (7) – (9), (10) can be rewritten as:

$$\Big(A - 2B\,x_i - B\,x_j - \eta\kappa - \gamma\,\eta\,(\eta\,x_i + q_i(x_i, x_j))\Big) + \Big(- b\,q_i(x_i, x_j)\frac{\partial q_j(x_i, x_j)}{\partial x_i}\Big) = 0. \quad (11)$$

The first expression reflects the *direct effect* of x_i, holding wholesale quantities constant. This is the same term as the left-hand side of (4) and captures the impact of an increase in AS quantity on firm i's profit, absent any consideration of how AS output impacts the second stage wholesale market equilibrium. The second expression in (11) reflects the *strategic effect* that occurs through the effect of x_i on firm i's rival's wholesale quantity q_j in the second stage. The strategic effect can be rewritten as:

$$\frac{\partial \pi_i}{\partial q_j}\,\frac{\partial\,q_j(x_i, x_j)}{\partial\,x_i} = -\,(b\,q_i)\,\frac{b\,\eta\,\gamma}{(3b+\gamma)\,(b+\gamma)} < 0. \quad (12)$$

The strategic effect is negative; increasing firm i's AS output increases its second stage wholesale marginal cost of output, causing its wholesale equilibrium output to decrease, and its rival's equilibrium wholesale output to increase. An increase in firm i's rival's output reduces its profit. Recognizing this effect will lead firm i to choose a lower AS market output. This suggests a key result: *as a result of strategic considerations, in the sequential model firms reduce AS output relative to the simultaneous timing model, subsequently increasing output in the wholesale market as its marginal cost of wholesale production decreases.*

The impact of AS output on wholesale market outcomes can be readily observed by investigating the second-stage wholesale output best-response function. Using (3) and holding x_i as a constant, firm i best-response function in the wholesale market is given by:

$$BR_i(q_j) = \frac{a - \kappa - b\,q_j - \eta\,\gamma\,x_i}{2b+\gamma}. \quad (13)$$

A decrease in x_i shifts firm i's best response function outward indicating it wants to produce more output for any output level chosen by its rival. Because the (negative) strategic effect detailed above is faced by both firms, this creates incentives for each firm to reduce its AS output below the equilibrium level in the simultaneous model. This causes both firms' second stage wholesale market best-response functions to shift outward relative to the case of simultaneous timing. This results in an increase in wholesale market outputs for both firms. Therefore, our model predicts greater wholesale market output and lower AS output in the sequential model than under simultaneous timing. Note that the effect of AS output on a firm's second stage best-response function is greater, the larger are η and γ. The larger these parameters, the greater the impact that AS output has on a firm's marginal cost function in the wholesale market. In Figure 1, the points A and B at the intersections denote the equilibria in the simultaneous and sequential move game, respectively.

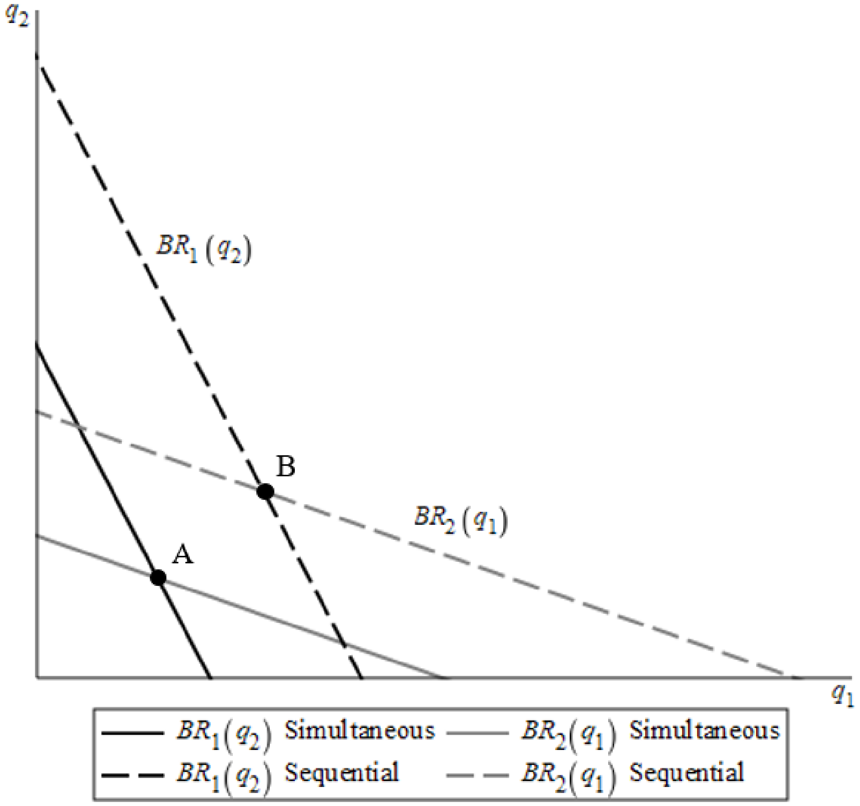
Using (3), (11), and (12), we solve for the first stage Nash Equilibrium $x_{Sequential} = x_1^* = x_2^*$, yielding the following:

$$x_{sequential} = \frac{(\gamma+b)\,(3b+\gamma)^2 A - (9b^2 + 11b\,\gamma + 3\gamma^2)\,b\,\kappa\,\eta - (2b+\gamma)^2\,a\,\eta\,\gamma}{3\,(3b+\gamma)^2\,(\gamma+b)\,B + b\,\eta^2\,\gamma\,(9b^2 + 11\,b\,\gamma + 3\gamma^2)}. \quad (14)$$

Combining (7), (8), and (14), we can write $q_1^* = q_2^* = q_{sequential}$ as:

$$q_{sequential} = \frac{\left[\left(3B + \eta^2\gamma\right) a - 3B\kappa - A\eta\gamma\right]\left(3b + \gamma\right)\left(b + \gamma\right)}{3\left(3b + \gamma\right)^2\left(\gamma + b\right) B + b\,\eta^2\,\gamma\left(9b^2 + 11\,b\,\gamma + 3\gamma^2\right)}. \tag{15}$$

Figure 1: Wholesale Market Best Response Functions by Model Timing



Notes: This figure illustrates the equilibrium outcomes of our sequential and simultaneous move models with the following parameters: $a = 500,\ A = 250,\ b = 0.75,\ \ B = 0.65,\ \eta = 0.75, \kappa = 0,\ \gamma = 0.25$.

To quantify the effect of sequential versus simultaneous timing, let $\Delta q = q_{sequential} - q_{simultaneous}$ be the difference between the volume supplied by an individual firm in the wholesale market in the sequential and simultaneous models. Using (6) and (15), it can be shown that:

$$\Delta q = \frac{1}{3}\,\frac{b^2\,\eta^2\,\gamma^2\left[\eta\,\gamma\left(a\eta - A\right) + 3B\left(a - \kappa\right)\right]}{\left(b\,\eta^2\,\gamma + 3B\,b + B\,\gamma\right)\left[b\,\eta^2\,\gamma\left(9b^2 + 11b\,\gamma + 3\gamma^2\right) + 3B\left(\gamma + 3b\right)^2\left(\gamma + b\right)\right]}.$$

Likewise, let $\Delta x = x_{sequential} - x_{simultaneous}$ be the difference between AS market output in the sequential and simultaneous models. Using (5) and (14), it can be shown that:

$$\Delta x = -\frac{1}{3}\,\frac{b^2\,\eta\,\gamma\,(3b+\gamma)\,[\eta\,\gamma\,(a\,\eta - A) + 3B\,(a-\kappa)]}{(b\,\eta^2\,\gamma + 3B\,b + B\,\gamma)\,[b\,\eta^2\,\gamma\,(9b^2 + 11b\,\gamma + 3\gamma^2) + 3B\,(\gamma + 3b)^2\,(\gamma + b)]}.$$

Under the parameter restrictions required for an interior solution, it follows that $\Delta q > 0$ and $\Delta x < 0$ as discussed intuitively above; with sequential timing, firms reduce AS market output because of the strategic effect in the wholesale market, resulting in increased wholesale market output. This results in a decrease in the wholesale price and an increase in the AS market-clearing price.

Finally, it is informative to consider what model features impact the extent to which the wholesale market price changes as a result of the change in the AS quantity. We have shown that moving from simultaneous to sequential timing causes firms to decrease the AS market output in order to reduce their subsequent marginal costs in the wholesale market. In the wholesale market, firm i's marginal cost curve is given by $\kappa + \gamma(\eta x_i + q_i)$. Reducing AS output by Δx_i therefore shifts i's marginal cost curve down by the amount $\gamma\eta\Delta x_i$. In equilibrium, this shift is symmetric across firms. It can be shown that the rate of pass-through into the wholesale price due to the shift of the marginal cost curve is given in our context by $\frac{2b}{3b+\gamma}$.[7] Hence, the extent to which a marginal cost reduction in the wholesale market (as a result of a reduction in AS output) is passed through into the wholesale price will depend upon the slope of the wholesale market demand function and the slope of the marginal cost curve. In other words, an increase in the marginal cost parameter (γ) may reduce the pass-through rate. In contrast, an increase in the slope demand curve (b) would expand the pass-through rate.

3 Numerical Analysis

In this section, we employ data from Alberta's electricity market. The objective of this empirical analysis is not to capture all features of AS and wholesale markets in practice, but rather illustrate our model's results in a setting that reflects key features of real-world electricity markets. We extend our theoretical model to capture a number of important features of Alberta's electricity market.

3.1 Data

We use data from a number of sources covering the period January 1, 2020 to December 31, 2020. First, we use publicly available data from the Alberta Electric System Operator (AESO) that includes hourly generation unit-level wholesale market production and

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[7] This is a general result for a symmetric Cournot duopoly with a linear demand function and linear marginal cost curves. For example, in a Cournot duopoly with marginal cost curves given by $c_0 + c_1 q$ and a market demand curve of $P = a - bQ$, the derivative of the Cournot equilibrium price with respect to c_0 is $\frac{2b}{3b+c_1}$.

bids, import supply, available transmission capacity limits from neighboring provinces, market demand, and the ownership and characteristics of generation assets. Second, we use daily natural gas prices from Alberta's Natural Gas Exchange (NGX). Third, we use weekly Wyoming's Powder River Basin coal prices provided by the U.S Energy Information Administration to compute fuel input costs for coal units.[8] Fourth, ancillary market data was provided to us by the MSA.[9] These data provide hourly unit-specific information on firms' price-quantity offers in the AS market and the quantity procured for each AS product. These data will be used to estimate the residual demand facing strategic firms in the AS market.

Table 1 presents summary statistics of several key variables in our analysis. This table demonstrates that there is considerable variation in wholesale demand and prices. Compared to the wholesale market, the AS market is small and the price demanded by firms to supply the AS product is lower.[10] This latter observation likely reflects the fact that firms are only called upon to physically supply AS output in a subset of hours. Import supply and capacity are a relatively small portion of wholesale demand reflecting the limited interties with neighboring jurisdictions. Finally, Alberta has a sizable quantity of wind available in any given hour with a relatively limited variation.

Table 1: Summary Statistics

Variable	Units	Mean	Std. Dev	Min	Max
Wholesale Demand	MWh	9,619.98	873.06	7,200.29	12,165.89
Wholesale Price	$/MWh	46.72	92.14	0.00	999.99
AS Quantity	MWh	636.96	91.82	456.00	892.00
AS Price	$/MWh	13.03	66.35	0.36	891.92
Import Supply	MWh	451.54	285.71	0.00	1,119.00
Import Capacity	MWh	824.97	225.94	153.00	1,198.00
Wind Output	MWh	1,750.35	36.18	1,517.00	1,791.00

3.2 Alberta's Ancillary Services and Wholesale Markets

3.2.1 Wholesale Market

Alberta's wholesale electricity market operates as an hourly uniform-price procurement auction. For each hour, generation firms compete by submitting up to seven price-quantity offer blocks for each generation unit in their portfolio, representing the price at which they are willing to supply electricity. Market-clearing is facilitated by the AESO who stacks firms'

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[8] We use the Bank of Canada's exchange rate to translate coal prices from US Dollars to Canadian Dollars.

[9] These data were provided to the authors under a non-disclosure data agreement.

[10] Sections 3.2.1 and 3.2.2 summarize details of Alberta's wholesale and AS markets. Section 3.5 describes how we construct the AS quantity and price variables presented in Table 1, given there are multiple AS products.

offers in order of least-cost and sets the spot price equal to the bid that intersects market demand. All firms receive this uniform market-clearing price. Unlike other jurisdictions with locational pricing, there is a single province-wide wholesale price.

Alberta's market is an "energy-only" market, meaning that there are no supplemental payments for capacity. Generators rely solely on revenues from generating electricity in wholesale and AS markets to recover their fixed and variable costs. Importantly, the exercise of market power is explicitly permitted, with no bid mitigation. Substantial market power has been observed in high demand hours; see for example Brown and Olmstead (2017). This makes Alberta an ideal setting to analyze firms' strategic incentives.

In 2020, Alberta's wholesale electricity market was moderately concentrated with the five largest firms controlling 64% of the province's generation capacity. The remaining capacity is offered by a large fringe of small firms (MSA 2020). The largest firm in terms of offer control was TransAlta, with control of 21% of generation capacity. The second largest firm by offer control was the Balancing Pool with control over 14% of generation capacity, followed by Heartland (11%), ENMAX (9%), and Capital Power (8%).[11] Despite the relatively moderate market concentration, prior literature has shown that the unique properties of electricity markets make it particularly susceptible to the exercise of market power (Borenstein, Bushnell, and Knittel 1999). In 2020, 47% of installed generation was natural gas based, followed by coal with 33% of installed capacity, wind (11%), hydroelectic generation (5%), and biogas/biomass (3%) (AUC 2020).

3.2.2 Ancillary Service Markets

The AESO procures three type of operating reserves (regulating, spinning, and supplemental), in both active and standby forms (MSA 2009). Regulating reserves address small minute-to-minute demand and supply differentials, while spinning and supplemental reserves (together, contingency reserves) are designed to address larger disruptions, such as the failure of large generators. Standby operating reserves are called upon when active reserves are unable to produce, which occurs rarely in practice. Importantly, while assets that are awarded standby contracts may still offer the quantity under those contracts into the wholesale market, quantities under active operating reserve contracts cannot be offered into the wholesale market. As a result, in the remainder of this section we focus on active reserves.

In contrast to the wholesale market which clears on an hourly basis and in which firms can adjust bids up to two hours before the hour, operating reserves are procured and set by the AESO in auctions held the business-day prior to market-clearing; hence, Alberta's AS and wholesale markets clear sequentially, with the AS market clearing before the wholesale market. Four different active reserve products (on peak, off peak, AM super peak, and PM

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[11] Upon restructuring of Alberta's electricity markets in the late 1990s, certain generation units were "virtually divested" through long term (20 year) contracts, known as the Power Purchase Arrangements (PPAs). Under the PPAs, the PPA buyer had offer control of a generating unit and bid its output into the wholesale market. Assets for which these contracts were not purchased, or were exited from early by the buyer, were controlled by an agency known as the Balancing Pool. See Brown, Eckert, and Shaffer (2022) for discussion of the PPAs and the Balancing Pool.

super peak) are procured by the AESO in each of the regulating, spinning, and supplemental categories, where these products differ by time period. On peak refers to the time period from 7:00 AM to 11:00 PM, while off peak refers to the remaining hours. The AM super peak period stretches from 5:00 AM to 8:00 AM, while the PM super peak period stretches from 4:00 PM to midnight in November, December, and January, but begins at 5:00 PM in other months (AESO 2020). These super peak products serve as supplementary AS procurement in addition to the AS quantities procured for on and off peak hours. The amounts procured of each product are based on AESO's forecasted requirements, which are posted in advance on its website.

Similar to the wholesale market, generation firms submit bids for each of their generation units that they want to use to supply a particular AS product. The AESO stacks these bids in terms of least-cost until there is sufficient supply to meet the AS demand for a given reserve product. The last bid accepted is the marginal bid.

The final AS price is determined by a different, more complex, process than in the wholesale market. MWhs that win in an active reserve auction are paid the subsequent realized wholesale price for the hours associated with the product, plus a premium (which is often negative and therefore a discount).[12] The premium is equal to the average of the marginal offer for that reserve product and the "AESO bid price" , which is known to the bidders. As an example, if the AESO bid price is set at \$100/MWhs and the marginal offer is -\$120/MWhs, then winning bidders would receive the wholesale price less a \$10 discount (i.e., $(100-120)/2 = -10$). It is important to note that the AS price is provided to suppliers of the AS product regardless of whether they are called upon to supply the AS product in real-time. In addition, active reserve providers are also paid the wholesale price for any electricity generated.

Regulating and contingency reserves differ in terms of the number of generating assets that are able to provide them. To provide regulating reserves, a generator must have equipment installed that allow the regulator to automatically control their generation in real-time. MSA (2009) reports that as of 2009 only 18 generating assets in Alberta were eligible to provide regulating reserves. Over the year 2020, only 16 generating units, under the offer control of 9 firms, actually provided regulating reserves. In contrast, in 2020, active spinning reserves were provided by 35 assets (15 firms), while supplemental active reserves were provided by 47 assets (21 firms).

The active AS market is highly concentrated. In 2020, TransAlta provided the highest percentage of all three types of active operating reserves, by MWhs: 69%, 63%, and 48% of regulating, spinning, and supplemental reserves, respectively. The second highest market shares in each category were ENMAX (24%) in regulating reserves, the Balancing Pool (16%) in spinning reserves, and Heartland Generation (11%) in supplemental reserves.

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[12] The premium is often negative because firm's bids in the AS market are often negative reflecting a discount below the realized wholesale price they are willing to accept to provide the AS product.

3.3 Estimation Methodology

In this section, we describe how we adapt our model to fit the characteristics of Alberta's electricity market. Our objective is to use our modeling framework to capture key features of Alberta's electricity market, while balancing numerical tractability.

Recall from Section 3.2.1, Alberta's market has five large firms and a fringe of small producers. One of the large firms, the Balancing Pool, is a government-owned agency that is observed to offer its supply near estimates of its generation units' marginal costs.[13] Consequently, we model the Alberta setting as one in which there are four large strategic firms behaving as Cournot producers in both the AS and wholesale markets, taking the supply from price-taking fringe producers, and imports in the case of the wholesale market, as given.

In the wholesale market, we formulate the price-elastic demand function facing the strategic Cournot producers as the perfectly price-inelastic wholesale demand, net of price-responsive supply from importers from neighboring jurisdictions and fringe producers. In the AS market, the AS demand function represents the pre-specified AS quantity set by the AESO, net of price-responsive supply from fringe firms that are observed to compete in these auctions. Unlike the wholesale market, importers cannot supply the AS product. More details on how these residual demand functions are constructed and how we deal with the complexities of the AS market will be provided below.

We compute unit-level marginal cost functions for the four large strategic firms and estimate linear marginal cost functions associated with generating output. This is consistent with the cost functions utilized in our model. In addition to having generation resources that can be called upon to supply output (i.e., "dispatchable resources"), firms have must-run generation units (e.g., wind and cogeneration) whose supply into the wholesale market is exogenously determined and has zero marginal cost. We take this supply as given and assume the strategic firms make output decisions in the wholesale and AS markets using their dispatchable units.

After establishing parameter estimates for the wholesale and AS residual demand functions and firms' marginal cost functions, we adapt our model to consider four firms and permit zero marginal cost must-run generation, and use the equilibrium wholesale and AS market output levels to numerically solve the simultaneous and sequential move models for each hour in our sample. In each setting, our model can be translated into a mixed complementarity problem (MCP) where we allow for the presence of a zero-bound on AS market output.[14] We utilize the PATH solver in GAMS and the University of Wisconsin's NEOS server to solve the large number of model cases (Czyzyk, Mesnier, and More 1998; Ferris and Munson 2000).[15]

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[13] See Brown, Eckert, and Shaffer (2022) for additional details on the Balancing Pool and its offer behaviour.

[14] Under our current parameterization, we do not reach an outcome where a firm wants to supply zero dispatchable wholesale output.

[15] See Appendix A for a detailed summary of the equilibrium conditions used in the numerical analysis.

3.4 Marginal Cost Functions

We estimate the marginal cost of each fossil-fuel generation unit using coal (C) and natural gas (G) price data (p_t^C, p_t^G), unit-specific heat-rates that represent thermal efficiencies for each asset j (HR_j), variable operating and maintenance (O&M) costs, and unit-specific environmental compliance costs (e_j).[16] An asset j's marginal cost of production (in \$/MWh) equals the summation of its fuel costs ($p_t^l \times HR_j$ for $l = C, G$), variable O&M costs, and environmental compliance costs.

Data on unit-specific heat rates for natural gas units were provided to us by Alberta's Market Surveillance Administrator, the Alberta Utilities Commission, and the Alberta Electric System Operator. Coal unit heat rates were obtained from CASA (2004). We use data from EIA (2020) to compute technology-specific variable O&M costs; these costs were translated to Canadian dollars using Bank of Canada exchange rates. Alberta has a carbon pricing policy with a price of \$30 per tCO2e during our sample period that charges fossil-fuel units based on their emissions intensity above an industry benchmark. We utilize the methods established in Brown, Eckert, and Eckert (2018) to compute the environmental compliance cost of each generation unit.

There are a large number of wind and cogeneration facilities in Alberta. Cogeneration units generate heat and electricity as a by-product of an on-site industrial process (e.g., oil-sands extraction). For these facilities, electricity that is not consumed on-site is sold in the wholesale market and offered at a price of \$0/MWh. Wind output is exogenously determined and also bids-in at a price of \$0/MWh. As noted above, we define output from these units to be must-run and have a marginal cost of zero. For a small number of hours, several natural gas-based cogeneration units submit non-zero bids into the wholesale market and produce output beyond their on-site needs. In these cases, we estimate the marginal cost of this output as we do for a natural gas generator.

Finally, there are several small hydroelectric facilities. Computing the marginal cost of these units is complicated by the fact that hydro units can shift their generation potential across time periods. As a result, the marginal cost of these units represent the opportunity cost of using the energy at some other point in time. Further, hydro facilities face other complex regulatory and ecological constraints. We follow the approach employed by Borenstein, Bushnell, and Wolak (2002), Mansur (2007), and Brown and Olmstead (2017) and assume that the output generated by the hydro units is identical to the level that would be produced by a price-taking firm. This results in us taking hydro output as given and analyzing the strategic firms' use of fossil-fuel units to meet the remaining demand.[17]

For each hour, we stack each firm's dispatchable generation units in order of least-cost to formulate a step-wise discontinuous marginal cost function. We approximate the observed cost function using a linear regression to establish a linear marginal cost curve for each hour. We use these estimates to construct a month-by-hour representative marginal cost function

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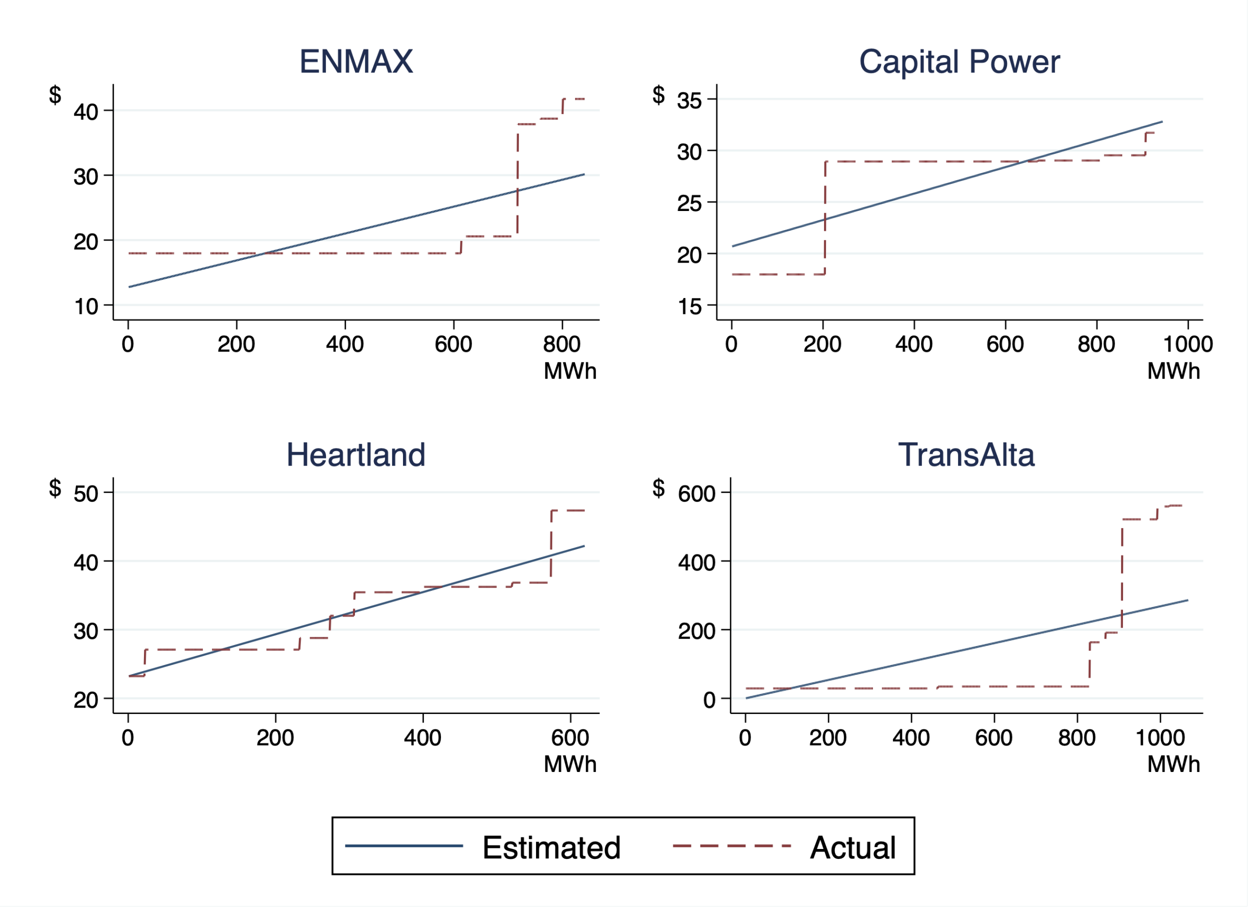
[16] Unit heat rates capture the rate at which a generation asset converts fuel into electricity.

[17] The potential biases from making this assumption are mitigated by the fact that hydroelectricity only represents 2.5% of total output in Alberta in 2020 (AUC 2020).

for each of the four strategic firms.[18] These cost functions are utilized to represent the cost of supplying dispatchable output in either the wholesale or AS markets.

Figure 2 provides a representative observed and estimated marginal cost function for each firm in our sample. The linearization of marginal cost fit the observed marginal cost curves reasonably well with average R-squared values ranging from 0.66 - 0.77.

Figure 2: Observed and Estimated Marginal Costs by Firm - January 7, HE 1



As highlighted in Figure 2, our cost function estimates reveal important asymmetries across firms; see also Table C.2 in Appendix C.1, which reports average cost function parameters over our sample period for each of the four firms. While Heartland, Capital Power, and ENMAX exhibit relatively flat marginal cost curves, with average constant marginal cost terms (κ) ranging from 11.41 to 23.02 and average slope parameters (γ) from 0.02 to

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[18] For one of the large firms, TransAlta, this linear approximation results in cases where the intercept of the estimated marginal cost function is negative. This occurs because TransAlta has several small high-cost units that pull-up the slope of the linear function. In these circumstances, we fix the intercept of the estimated marginal cost function at zero.

0.03, TransAlta's marginal cost function generally involves a lower constant marginal cost component ($\kappa = 7.39$ on average) but a much steeper slope ($\gamma = 0.19$ on average). This steep slope of TransAlta's marginal cost curve comes from high offers from its hydroelectric units, which as discussed above are taken as reflective of marginal cost. Hydro marginal costs may be high because of ecological or regulatory constraints, or because of the opportunity cost arising from not employing the resource in another hour. As a result of this steeper slope, we anticipate greater strategic incentives in the AS market under TransAlta's cost function.

Another key parameter in the total cost function in (1) is $\eta \in (0, 1]$, which places a weight of less than or equal to one on the AS output in the cost function, to reflect the possibility that the AS output committed in the AS market may not be physically called upon to generate, incurring the associated costs of production. We do not have access to data that details when and how much AS is physically produced. As noted above in Section 3.2.2, there are three AS products, Regulating, Spinning, and Supplemental. MSA (2009) indicates that approximately 50% of the AS procured to provide Regulating Reserve will be physically called upon to supply output. The remaining products are called upon infrequently (in $\approx 1\% - 2\%$ of hours). To provide a lower bound on the η parameter, we set η equal to 50% times the proportion of AS output that is represented by Regulating Reserve. This value will be denoted by $\underline{\eta}$ and is considered to be a lower bound because the generation capacity to be used to provide the active AS products is often unavailable to supply this output to the wholesale market regardless of whether it is actually called upon to generate in the AS market. We also consider a case where $\eta = 1$ to serve as an upper bound on the strategic effect that committing to AS output has on wholesale market outcomes. We will denote this case as $\eta = \overline{\eta} = 1$.

3.5 Residual Demand Estimation

We estimate residual demand faced by the four strategic firms in the wholesale market in two parts. First, there are imports supplied from neighboring jurisdictions into Alberta. Imports are scheduled and considered to be must-run (i.e., are bid-in at a price of \$0/MWh). Treating these MWhs as must-run would be inappropriate because importers make their decisions based in part on their expectations of the wholesale spot price in Alberta. Consequently, we follow the approach in Mansur (2007), Bushnell, Mansur, and Saravia (2008), and Brown and Olmstead (2017) and use a reduced-form approach to estimate the hourly price-responsive supply of electricity from neighboring jurisdictions British Columbia, Montana, and Saskatchewan.

For each hour t, we estimate imports as a function of the wholesale price p_t^w as follows:

$$\begin{aligned} Q_t^{IM} \; &= \; \beta_0 + \beta_1 \, p_t^w + \gamma \, f(\text{Import Capacity}_t) + \beta_2 \, \text{Holiday}_t + \sum_{k=1}^{6} \theta_k \, \text{DOW}_{kt} \\ &\qquad + \sum_{h=2}^{24} \omega_h \, \text{Hour}_{ht} + \sum_{m=2}^{12} \delta_m \, \text{Month}_{mt} + \varepsilon_t \end{aligned} \tag{16}$$

where Q_t^{IM} is the quantity of imports into Alberta, $f(\text{Import Capacity}_t)$ is a vector of import capacity limits from neighboring jurisdictions, and Holiday_t, DOW_{kt}, Hour_{ht}, and Month_{mt} are calendar controls for holidays, day of week, hour, and month, respectively. Import capacity limits are included to control for variation in hourly intertie capacities that physically restrict imports. The calendar variables control for systematic input supply shocks and demand variation that impact import decisions. ε_t is the error term. The regression is estimated with Newey–West heteroskedastic and autocorrelation robust standard errors with 24 lags.

The wholesale electricity price p_t^w is endogenous to the level of imports. This can result in attenuation bias on the key coefficient estimate $\widehat{\beta}_1$. We employ an instrumental variables (IV) approach using day-ahead forecasted demand as the excluded IV. Forecasted demand is a valid IV because wholesale demand is perfectly price-inelastic and exogenously determined by factors such as weather and hourly and seasonal patterns. The vast majority of customers in Alberta face fixed retail prices that vary at most monthly. Further, the day-ahead demand forecast only impacts imports through the way it affects the expected wholesale market price.

The IV regression results are reported in Table B.1 in Appendix B. As expected, failure to account for the endogeneity of the wholesale price in the import supply function leads to attenuation bias in the pool price coefficient. In the first-stage of the IV regression, forecasted demand has a positive and statistically significant effect on the pool price.[19] The average estimated price-elasticity of import supply equals 0.27.

Second, we use bid data from the fringe firms to establish an hourly fringe supply curve in the wholesale market. More specifically, we order the fringe supply in terms of least-cost and run a linear regression to approximate the fringe supply curve. Ito and Reguant (2016) employ a similar approach to estimating the strategic firms' residual demand function. We utilize the estimated hourly linear import and fringe supply functions in the wholesale market to construct the residual demand faced by the strategic firms.

For any given price, the residual demand equals the perfectly price-inelastic market demand minus the estimated supply from imports and fringe firms. The average price-elasticity of residual demand facing the large incumbent firms is -0.066. This falls in line with estimates for the PJM and New England regions of the United States found in Bushnell, Mansur, and Saravia (2008).

We now describe how we translate data from Alberta's AS markets into a form that can be analyzed with our modeling framework. Our objective is not to capture all features of Alberta's AS market (described in Section 3.2.2), but rather to use characteristics of Alberta's market as a setting to illustrate the strategic implications of AS-wholesale market competition.

Unlike the wholesale market where there is a single product procured in each hour, there are three AS products that are procured in multi-hour blocks. We aggregate the AS products into a single hourly product by calculating the total AS quantity being procured across each of the products. We expand the four multi-hour AS product blocks to the hourly level based

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[19] The Kleibergen-Papp rk Lagrange-Multiplier test statistic for weak IVs rejects the null that our IV is weak.

upon the specific hours covered by each block. As described in Section 3.2.2, AS market bids reflect a discount relative to the realized wholesale price. We assume that firms have perfect foresight on the realized wholesale price level. In particular, we compute their *ex-post* realized final AS bids once the wholesale price is determined.[20] These final bids are used to represent the price at which they are willing to provide the AS product.[21]

Similar to the wholesale market, we follow the approach employed in Ito and Reguant (2016) and use the final AS bids of the fringe firms to establish an hourly fringe supply curve in the AS market. We run a linear regression to approximate the fringe supply curve. For any given hour, the residual AS demand curve faced by the strategic firms equals the price-inelastic total AS procurement quantity set by the regulator minus the estimated AS fringe supply curve. The average price-elasticity of fringe AS market supply equals 0.20. This highly inelastic AS fringe supply is consistent with the limited fringe supply in the AS market.

3.6 Numerical Results

In this section, we present the numerical results of our model. We first consider a setting with 4 symmetric firms. To illustrate our primary results, Table 2 provides numerical results for the symmetric case, using Heartland's cost function and must-run parameters for each firm, when $\eta \in \{\underline{\eta}, \overline{\eta}\}$.[22]

Table 2: Symmetric Firms - Heartland Parameters

Panel (a)	$\overline{X}_{sim}$	$\overline{X}_{seq}$	$\% \Delta \overline{X}$	$\overline{P}_{AS,\, sim}$	$\overline{P}_{AS,\, seq}$	$\% \Delta \overline{P}_{AS}$	$\overline{TPC}_{AS,\, sim}$	$\overline{TPC}_{AS,\, seq}$	$\% \Delta \overline{TPC}_{AS}$
$\underline{\eta}$	161.36	155.28	-3.77	40.63	44.16	8.69	27,149.11	29,389.95	8.25
	(105.02)	(105.14)		(45.47)	(45.42)		(34,783.36)	(34,847.19)	
$\overline{\eta}$	110.31	76.02	-31.09	70.70	94.16	33.19	46,538.57	61,824.84	32.85
	(104.34)	(98.86)		(47.23)	(53.59)		(36,934.02)	(41,575.01)	
Panel (b)	$\overline{Q}_{sim}$	$\overline{Q}_{seq}$	$\% \Delta \overline{Q}$	$\overline{P}_{WS,\, sim}$	$\overline{P}_{WS,\, seq}$	$\% \Delta \overline{P}_{WS}$	$\overline{TPC}_{WS,\, sim}$	$\overline{TPC}_{WS,\, seq}$	$\% \Delta \overline{TPC}_{WS}$
$\underline{\eta}$	4,640.22	4,640.24	0.001	236.49	236.49	-0.001	2,297,334.00	2,297,291.00	-0.002
	(709.61)	(709.60)		(33.61)	(33.62)		(491,499.1)	(491,501.2)	
$\overline{\eta}$	4,637.33	4,638.60	0.03	236.97	236.76	-0.09	2,301,992.00	2,299,979.00	-0.09
	(709.16)	(708.97)		(33.71)	(33.71)		(492,991.9)	(492,891.2)	

$\overline{X}_{sim}$ and $\overline{X}_{seq}$ in Panel (a) of Table 2 represent the average total ancillary services quantity produced by the 4 firms under simultaneous and sequential timing, respectively; average AS prices are denoted by $\overline{P}_{AS,\, sim}$ and $\overline{P}_{AS,\, seq}$. The percentage changes in the average AS output and price from moving from the simultaneous to sequential timing are given by $\%\Delta\overline{X}$ and $\%\Delta\overline{P}_{AS}$.

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[20] We also compute the final AS bids using the day-ahead forecasted price. Our results are robust to this alternative approach.

[21] The AS price in Table 1 is computed by calculating the highest final bid accepted for each product and then weighting these "marginal" AS bids by the AS quantity being procured for each product.

[22] The outcomes generated with Capital Power's, ENMAX's, and TransAlta's cost functions and must-run values are available in Appendix C.2 (see Tables C.3, C.4, and C.5).

As illustrated in Table 2, moving from simultaneous to sequential timing reduces the average total AS output produced by the strategic firms by -3.77% under $\underline{\eta}$ and by -31.09% under $\overline{\eta}$. As a consequence, the average AS price increases by 8.69% under $\underline{\eta}$ and by 33.19% under $\overline{\eta}$. The presence of the strategic effect resulting from the increasing marginal cost curves gives firms an incentive to reduce their first-stage AS outputs. This action reduces the second stage marginal costs and shifts the firm's wholesale market best-response function outward. Consequently, we observe less output by the 4 strategic firms in the AS market in the sequential move setting. The larger effect of sequential timing under $\overline{\eta}$ reflects the greater strategic effect that arises when marginal cost curves are more steeply sloped.

In light of these large effects, we can anticipate sizable effects on the total procurement costs in the ancillary services markets. For each setting $j \in \{sim, seq\}$, we calculate the total AS procurement cost ($TPC_{AS,j}$) by multiplying the aggregate amount of the AS products procured (from both the strategic firms and the competitive fringe) by the market-clearing AS price. The percentage change in the total AS procurement cost of moving from simultaneous to sequential move setting is represented in Panel (a) of Table 2 by $\%\Delta\overline{TPC}_{AS}$. Considering the case where $\eta = \underline{\eta}$, the effect of going from simultaneous to sequential timing leads to an average increase in the total AS procurement costs of 8.25%. When considering the $\eta = \overline{\eta}$, $\%\,\Delta\overline{TPC}_{AS}$ increases to 32.85%.

These results demonstrate that the change in market timing can have a large impact on AS market outcomes. These large changes are facilitated by the highly inelastic residual demand function in the AS market that is the consequence of the steep fringe AS supply curve. Small changes in AS output, due to the presence of the strategic effect, has a substantial impact on the market-clearing price and total procurement cost in the AS market.

We now turn our attention to the wholesale market presented in Panel (b) of Table 2. Let $\overline{Q}_{sim}$, $\overline{Q}_{seq}$, $\overline{P}_{WS,\,sim}$ and $\overline{P}_{WS,\,seq}$, represent the average wholesale quantity of electricity (including must-run supply) produced by the 4 firms, along with the wholesale prices, under simultaneous and sequential timing. The average percentage changes in quantities and prices from moving from simultaneous to sequential move are given by $\%\,\Delta\overline{Q}$ and $\Delta\overline{P}_{WS}$. We find that the wholesale output of the strategic firms is higher under sequential timing, and the wholesale price is lower. However, as illustrated by Panel (b) of Table 2, the effects of sequential timing on wholesale quantities and prices are small, both in absolute and percentage terms. Compared to the AS market effects, the smaller wholesale market effects are driven in part by the more elastic fringe supply function.

Finally, we assess the percentage change in the average total procurement cost ($\%\Delta\overline{TPC}_{WS}$) in the wholesale market. In each hour and setting $j \in \{sim,\ seq\}$, the wholesale procurement cost ($TPC_{WS,j}$) equals the total wholesale output multiplied by the market-clearing price. The total wholesale procurement costs are lower in the sequential move setting due to the lower wholesale price. However, consistent with the small price differences, the difference is small in magnitude.

While the reduction in total procurement cost in the wholesale market is small in percentage terms, it has potentially important policy implications because of the large size of the wholesale market relative to the AS market. Combining procurement costs in the two markets, we find that even though AS procurement costs increase by 8% and 33% in the $\underline{\eta}$ and $\overline{\eta}$ cases, these increases are effectively canceled out by the procurement cost reductions in the wholesale market. Total procurement costs across the two markets increase under sequential timing by only 0.09% and 0.57% in the $\underline{\eta}$ and $\overline{\eta}$ cases, respectively. Were policymakers to consider the AS market independently, the large percentage increases in AS procurement costs might lead to policy changes that are less justified when considering the total effect across both markets.

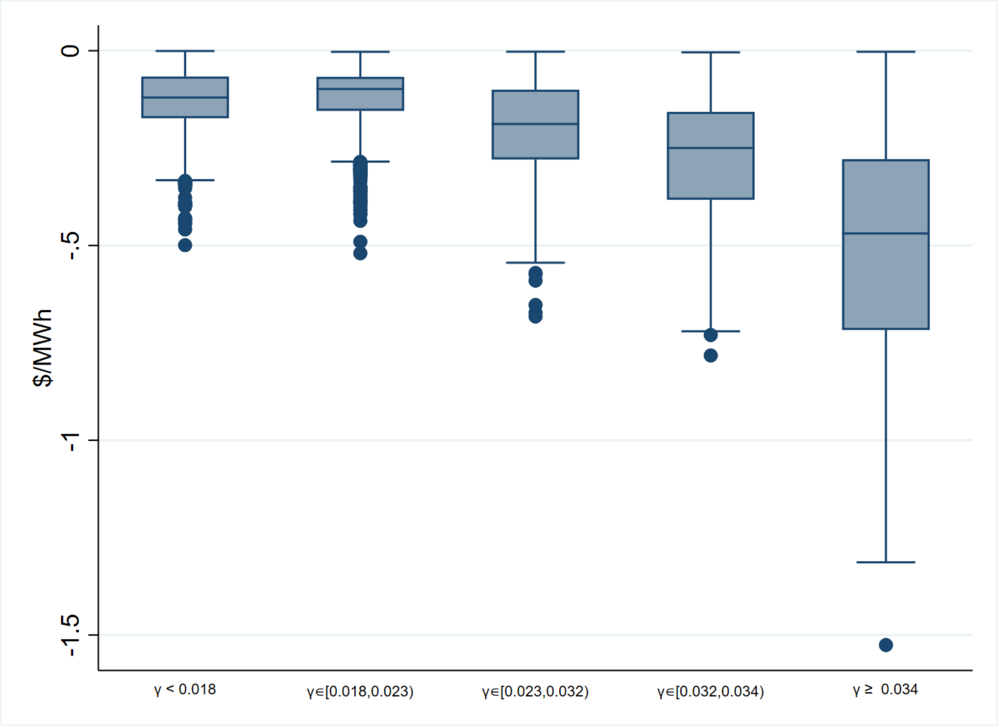

Figure 3: Wholesale price effect from sequential timing, by quintiles of γ - Heartland parameters

While the wholesale market effects of sequential timing are small on average, their magnitudes can increase under certain conditions. As observed in Section 2, a key determinant of the strength of the strategic effect and the pass-through of marginal cost increases into wholesale prices is the parameter γ, which determines the slope of the marginal cost curve. Continuing with the Heartland parameters and focusing on the $\overline{\eta}$ case, Figure 3 provides a box plot of the wholesale price effect representing the difference between the simultaneous and sequential wholesale market prices, by quintiles of γ. This figure illustrates that the magnitude of the wholesale price effect increases as the slope of the marginal cost curve increases.

To understand better the effect of γ, we next consider the results from symmetric models using the marginal cost parameters of the other three firms: Capital Power, ENMAX, and TransAlta. Detailed results are reported in Tables C.3, C.4, and C.5. As expected, because of the similarities in their cost functions, the Capital Power and ENMAX parameters yield results closely resembling those from the Heartland Parameters. In contrast, using the parameters for TransAlta's marginal cost curve yields a larger (although still small) average wholesale price reduction of \$0.71/MWh, compared to \$0.21/MWh using the Heartland parameters. This increased wholesale market effect is likely the result of TransAlta's increased marginal cost slope, as noted in Section 3.4, leading to increased strategic effects.

However, it is important to note that the effect of γ on wholesale price effects from sequential timing can be nonlinear. To illustrate, Figure 4 provides a box-plot of the wholesale price effect from sequential timing by quintiles of γ, using TransAlta's cost function parameters and $\eta = \overline{\eta}$, and excluding hours in which there is a corner solution in the AS market in the simultaneous timing model (AS quantities of zero). Here we see that the largest price effects (a mean of -\$1.70 /MWh) occur in the fourth quintile, corresponding to values of γ between 0.2 and 0.24.

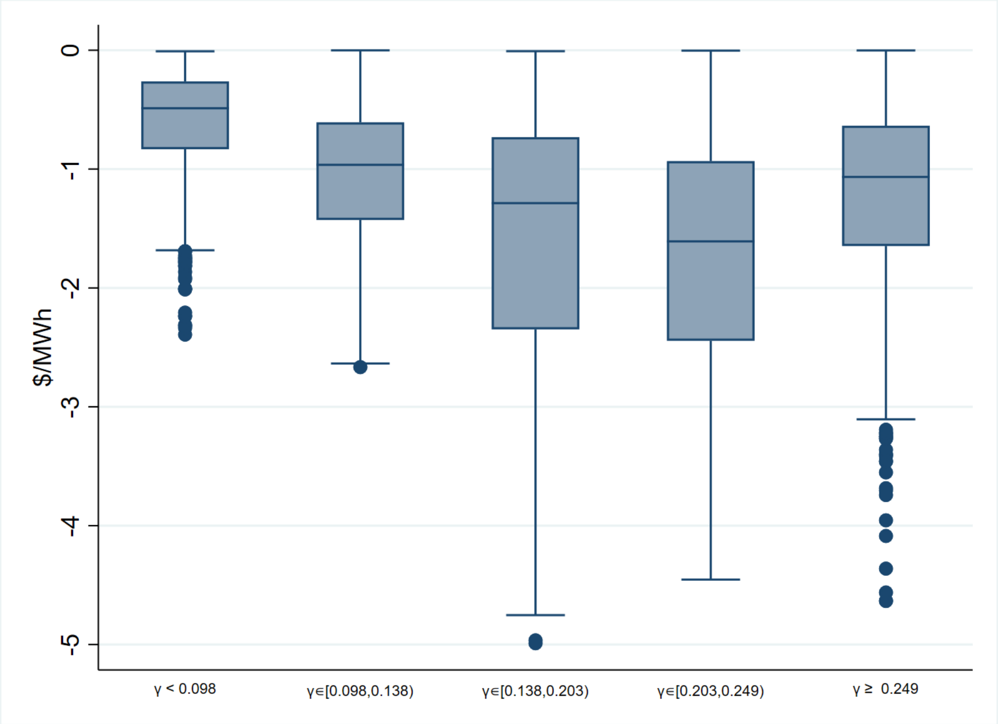

Figure 4: Wholesale price effect from sequential timing, by quintiles of γ - TransAlta parameters

The nonlinear effect of γ is related to two distinct effects of γ on the strategic effect in equation (12). As the slope of the marginal cost curve increases, the link between the AS and wholesale market stages increases, so that changes in a firm's AS output cause a greater shift in its wholesale market best response function, and ultimately has a greater effect on its rival's wholesale market output. This puts upward pressure on the strategic effect increasing the wholesale price effect from sequential timing. On the other hand, since increases in γ

correspond to increases in marginal cost, the strategic price effect of reducing AS output will apply to a smaller wholesale market output produced by firm i and such reductions in AS output will be less profitable. Eventually, as the slope of the marginal cost curve increases, the second effect outweighs the first.

Given the important role of γ, the large observed difference between the slopes of the marginal cost functions of TransAlta and the other three firms leads to the question of the strategic implication of sequential timing with asymmetric firms. Table 3 provides market-level numerical outcomes for the model with asymmetric firms (i.e., using each firm's estimated cost parameters and must-run quantities). At the market level, aggregate results in both the AS and wholesale markets are comparable to the symmetric case, with large effects in the AS market and small effects in the wholesale market. The similarity in aggregate results is not surprising, since three of the four firms have γ parameters that are similar in magnitude (see Table C.2).

More interesting in the asymmetric setting is to consider the implications of sequential timing on the market outcomes of individual firms. When $\eta = \underline{\eta}$, we find that TransAlta, the firm with the steepest marginal cost curve, reduces AS output by approximately 13 MW on average, or 38% in the sequential scenario relative to simultaneous timing; in contrast, the remaining three firms *increase* AS output slightly (up to 7% for ENMAX). The strategic incentive resulting from sequential timing is low for these firms due to their low γ values, and is dominated by the fact that in the AS market, Cournot competition implies that the firms produce strategic substitutes; hence, as TransAlta increases its AS output, the best-response quantities of the other three firms fall. The firm-level effects in the wholesale market are in the opposite direction, although small, with TransAlta increasing wholesale output by 0.7 MW and the other three firms reducing wholesale market output slightly by less than 0.2 MW each.

Table 3: Asymmetric Firms

Panel (a)	$\overline{X}_{sim}$	$\overline{X}_{seq}$	$\% \Delta \overline{X}$	$\overline{P}_{AS,\,sim}$	$\overline{P}_{AS,\,seq}$	$\% \Delta \overline{P}_{AS}$	$\overline{TPC}_{AS,\,sim}$	$\overline{TPC}_{AS,\,seq}$	$\% \Delta \overline{TPC}_{AS}$
$\underline{\eta}$	160.91	153.81	-4.41	40.96	45.27	10.53	27,378.26	30,150.11	10.12
	(104.55)	(103.61)		(45.72)	(46.09)		(35,001.14)	(35,377.45)	
$\overline{\eta}$	113.97	88.18	-22.63	69.97	87.91	25.64	46,228.94	57,973.48	25.41
	(98.40)	(92.87)		(50.62)	(58.06)		(39,551.69)	(45,170.32)	
Panel (b)	$\overline{Q}_{sim}$	$\overline{Q}_{seq}$	$\% \Delta \overline{Q}$	$\overline{P}_{WS,\,sim}$	$\overline{P}_{WS,\,seq}$	$\% \Delta \overline{P}_{WS}$	$\overline{TPC}_{WS,\,sim}$	$\overline{TPC}_{WS,\,seq}$	$\% \Delta \overline{TPC}_{WS}$
$\underline{\eta}$	4,623.42	4,623.59	0.004	239.29	239.26	-0.012	2,327,256.00	2,326,971.00	-0.01
	(682.32)	(682.33)		(37.42)	(37.42)		(528,945.6)	(532,939.2)	
$\overline{\eta}$	4,620.66	4,621.93	0.03	239.74	239.53	-0.09	2,331,765.00	2,329,717.00	-0.09
	(681.33)	(681.45)		(37.57)	(37.55)		(535,258.3)	(534,769.1)	

In the case of $\eta = 1$, the effects of sequential timing change. As η increases, AS output becomes more costly, which leads the firms to produce zero AS output in some hours under simultaneous timing, so that they are unable to reduce AS output further in response to the strategic effect; these corner solutions occur in 25%, 7%, 7%, and 65% of hours for Heartland, Capital Power, ENMAX, and TransAlta, respectively. In hours in which all four firms produce positive AS output in the simultaneous model, moving to sequential timing causes TransAlta to reduce its AS output by 19 MW, or 86% of its total AS output; the other three firms also reduce their AS output in these hours under sequential timing, but by smaller amounts (up to 16% in the case of Heartland). When $\eta = 1$, the strategic effect is larger, causing even firms with low values of γ to reduce AS output under sequential timing. TransAlta increases its wholesale output in these hours by 7 MW or 1.5%; the wholesale output of the other three firms falls marginally (less than 3 MW on average for all three firms).

4 Conclusion

In this paper, we assess the strategic implications of simultaneous versus sequential wholesale and ancillary service (AS) market-clearing. The exponential growth in renewable energy resources and the associated challenges with its variable output has led to increased interest in and importance of AS markets. A central design feature of AS markets is whether these markets clear before or with wholesale markets. Despite the importance of AS markets and continued concerns of market concentration in the electricity sector, the strategic implications of the timing of wholesale-AS market-clearing has not been explored in the literature.

To fill this gap, we develop a Cournot model to evaluate the interaction between the wholesale and ancillary services markets. In our model, we allow the provision of AS output to impact the firms' costs of supplying output in the wholesale market. This creates a linkage between the supply of wholesale and AS output.

We demonstrate that a strategic incentive arises in the setting where the AS market clears prior to the wholesale market. In particular, we show that firms have an incentive to reduce their AS output in this setting because it allows them to commit to competing more aggressively in the subsequent wholesale market. The presence of this strategic incentive leads to a higher AS market-clearing price, but puts downward pressure on the wholesale price. Consequently, the net effect of moving to sequential timing on the total procurement costs across both markets is ambiguous.

We employ data from Alberta's wholesale and AS markets to calibrate our theoretical model and quantify the impacts of sequential versus simultaneous market-clearing. We find that the presence of the strategic effect has a large impact on the AS equilibrium outcome, leading to AS price increases ranging from 8% to 33%. These large effects are driven by the highly inelastic supply of fringe producers limiting the competitive forces faced by the large strategic firms. Alternatively, we find that the change in wholesale-AS market timing has a minimal impact on the wholesale market. We find that the wholesale market price decreases when we move to sequential market-clearing, but this price-reduction is small in magnitude. This is driven in part by the more elastic fringe supply function in the wholesale market.

When computing the total procurement costs associated with both the wholesale and AS market, we find that total procurement costs increase as a result of moving to sequential market-clearing. However, the change in total procurement cost is small. While there is a large AS price increase putting upward pressure on procurement costs, the AS market is considerably smaller in magnitude compared to the wholesale market. Consequently, the small price-reduction in the wholesale market helps mitigate the large price increase observed in the AS market. Our results stress the importance of looking at the net effect across both markets given the countervailing impacts that sequential market-clearing has on the equilibrium outcomes in these markets.

Our modeling framework was designed to illustrate the implications of market timing on equilibrium outcomes in wholesale-AS market competition in a simplified setting to isolate the key forces at play. Future research could incorporate technical features of AS markets that could limit the types of resources that provide the various AS products. Consideration of these technical features could potentially increase the market concentration of certain AS products resulting in even larger AS price impacts due to the changes in market timing.

In addition, we use a simplified cost function to facilitate analytical results and numerical tractability. Future research could consider a more complex cost function that permits non-linear marginal cost or even a unit-level analysis. Such an analysis may generate larger wholesale market price effects under certain conditions. For example, if the unit providing AS is a peaker gas unit, then the firm's marginal cost curve in the wholesale market would experience a distinct upward shift at higher-levels of output which are often called upon to supply during high demand hours. This may lead to a larger wholesale price difference as the market timing varies in high demand hours where firms' incentives and abilities to exercise market power are magnified. Despite these additional features that may impact the quantitative results, the key strategic incentives of wholesale-AS market competition we have isolated will persist.

Finally, our numerical analysis results in wholesale and AS prices that are higher on average than observed prices. Prior studies have found that Cournot models can overestimate prices and market power in electricity market, but can predict observed outcomes reasonably well with the addition of forward contracts (see for example Bushnell, Mansur, and Saravia (2008)). In the current paper, we abstract from market features such as forward contracting in the interests of tractability. However, exploring the implications of forward contracting, with its own strategic incentives, on the strategic incentives in the AS market is a potential avenue for future research.

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Appendix A Numerical Analysis: Equilibrium Conditions

Define $m_i \geq 0$ to be the must-run quantity (e.g., wind output) produced by firm $i = 1, 2, 3, 4$. Using (2), the addition of must-run supply yields the following adjusted firm i profit function.

$$\pi_i(\cdot) \;=\; \left[a - b\sum_{j=1}^{4}(q_j + m_j)\right](q_i + m_i) + \left(A - B\sum_{j=1}^{4} x_j\right) x_i - \kappa_i\,(\eta x_i + q_i) - \frac{1}{2}\,\gamma_i\,(\eta x_i + q_i)^2 \tag{A.1}$$

where $q_i \geq 0$ and $x_i \geq 0$.

Subsection A.1 Simultaneous Move Game with 4 Firms

It is without loss of generality to focus on Firm 1. Using (A.1), firm 1 simultaneously chooses q_1 and x_1 to maximize profits, holding q_{-1} and x_{-1} constant, yielding the following first-order conditions:

$$\frac{\partial \pi_1}{\partial q_1} = a - b\sum_{i=1}^{4}(q_i + m_i) - b\,(q_1 + m_1) - \kappa_1 - \gamma_1\,(\eta\, x_1 + q_1) \leq 0 \quad \perp \quad q_1 \geq 0 \tag{A.2}$$

and

$$\frac{\partial \pi_1}{\partial x_1} = A - B\sum_{i=1}^{4} x_i - Bx_1 - \kappa_1\eta - \gamma_1\,\eta\,(\eta\, x_1 + q_1) \leq 0 \quad \perp \quad x_1 \geq 0. \tag{A.3}$$

where $\perp$ represents the complementarity conditions ensuring the non-negative output constraints are not violated. The first-order conditions for the other firms are analogous to the expressions (A.2) and (A.3). For each hour of our sample, this yields a system of 8 mixed complementarity equations and 8 endogenous variables (q_i and x_i for all $i = 1, 2, 3, 4$).

For the particular case where firms are symmetric, i.e., $q_i = q$ and $x_i = x$, the four first-order conditions yields a symmetric Nash equilibrium with the following AS and wholesale quantities for each firm:

$$x_{Simultaneous} = \frac{(5b + \gamma)A + (\gamma\, m - \kappa)\, 5b\,\eta - a\,\eta\,\gamma}{25Bb + \gamma\,(5B + 5b\,\eta^2)} \tag{A.4}$$

$$q_{Simultaneous} = \frac{(a - 5b\,m)\,(5B + \eta^2\gamma) - 5B\,\kappa - A\,\eta\,\gamma}{25Bb + \gamma\,(5B + 5\,b\,\eta^2)}. \tag{A.5}$$

Let the inverse demand function in the wholesale market with 4 (symmetric) firms be given by $P_{WS}(q) = a - b\,\sum_{i=1}^{4}(q_i + m_i)$. In equilibrium, the pass-through effect is given as follows:

$$\frac{\partial P_{WS}(q_{Simultaneous})}{\partial \kappa} = \frac{4Bb}{(\gamma + 5b)B + b\eta^2\gamma}. \tag{A.6}$$

Subsection A.2 Sequential Move Game with 4 Firms

In the sequential timing, the AS quantities are chosen before the wholesale market quantities. As presented in Section 2.3, we use backward induction to find the SPNE by first solving for the NE in the wholesale market. Conditional on x_1, x_2, x_3, and x_4, the second stage FOCs are the same as presented in equation (A.2). We assume that $q_i > 0$ such that (A.2) holds with equality. We verify that this condition is satisfied in equilibrium.

Next, we describe how we characterize the first-order conditions in the AS stage of the model. It is without loss of generality to focus on Firm 1. In the first stage, Firm 1's first-order condition can be obtained as follows:

$$\frac{d\pi_1}{dx_1} = \frac{\partial \pi_1}{\partial x_1} + \frac{\partial \pi_1}{\partial q_1} \cdot \frac{\partial q_1}{\partial x_1} + \frac{\partial \pi_1}{\partial q_2} \cdot \frac{\partial q_2}{\partial x_1} + \frac{\partial \pi_1}{\partial q_3} \cdot \frac{\partial q_3}{\partial x_1} + \frac{\partial \pi_1}{\partial q_4} \cdot \frac{\partial q_4}{\partial x_1} \leq 0 \quad \perp \quad x_1 \geq 0. \tag{A.7}$$

From the Envelope Theorem, we have that:

$$\frac{\partial \pi_1}{\partial q_1} \cdot \frac{\partial q_1}{\partial x_1} = 0. \tag{A.8}$$

Using (A.1):

$$\frac{\partial \pi_1}{\partial q_2} = \frac{\partial \pi_1}{\partial q_3} = \frac{\partial \pi_1}{\partial q_4} = -b\,(q_1 + m_1); \quad \textit{and} \tag{A.9}$$

$$\frac{\partial \pi_1}{\partial x_1} = A - 2Bx_1 - B(x_2 + x_3 + x_4) - \kappa_1 \eta - \gamma_1\,\eta\,(\eta\,x_1 + q_1). \tag{A.10}$$

Using (A.1) and (A.9), the remaining partial derivatives are given as follows:

$$\frac{\partial \pi_1}{\partial q_2} \cdot \frac{\partial q_2}{\partial x_1} = -\frac{b^2\,\eta\,\gamma_1 (b+\gamma_4)\,(b+\gamma_3)\,(q_1+m_1)}{z}; \tag{A.11}$$

$$\frac{\partial \pi_1}{\partial q_3} \cdot \frac{\partial q_3}{\partial x_1} = -\frac{b^2\,\eta\,\gamma_1 (b+\gamma_4)\,(b+\gamma_2)\,(q_1+m_1)}{z}; \tag{A.12}$$

$$\frac{\partial \pi_1}{\partial q_4} \cdot \frac{\partial q_4}{\partial x_1} = -\frac{b^2\,\eta\,\gamma_1 (b+\gamma_3)\,(b+\gamma_2)\,(q_1+m_1)}{z}; \tag{A.13}$$

where

$$z = 5b^4 + 4b^3\,(\gamma_1+\gamma_2+\gamma_3+\gamma_4) + 3b^2\,[\gamma_3\,(\gamma_1+\gamma_2+\gamma_4) + \gamma_4\,(\gamma_1+\gamma_2) + \gamma_1\gamma_2] + \\ 2b\,\{[(\gamma_1+\gamma_2)\,\gamma_4 + \gamma_1\gamma_2]\,\gamma_3 + \gamma_1\gamma_2\gamma_4\} + \gamma_1\gamma_2\gamma_3\gamma_4.$$

Using (A.8) – (A.13), we can characterize the mixed complementarity condition that specifies firm 1's optimal choice of x_1 in (A.7). Similar conditions can be derived for the remaining firms. For each hour of our sample, this yields a system of 8 equations and 8 endogenous variables (q_i and x_i for all $i = 1, 2, 3, 4$).

Focusing on firm 1 − and imposing symmetry, i.e., $q_i = q$ and $x_i = x$ − the strategic effect is now given by the following expression:

$$\frac{\partial \pi_1}{\partial q_2} \cdot \frac{\partial q_2}{\partial x_1} + \frac{\partial \pi_1}{\partial q_3} \cdot \frac{\partial q_3}{\partial x_1} + \frac{\partial \pi_1}{\partial q_4} \cdot \frac{\partial q_4}{\partial x_1} = -3b\,(q_1 + m_1)\,\frac{b\,\eta\,\gamma}{(\gamma + b)\,(\gamma + 5b)}. \tag{A.14}$$

Solving the four first-order conditions for the case where firms are symmetric yields a symmetric Nash equilibrium with the following AS and wholesale quantities for each firm:

$$\begin{aligned} x_{sequential} = {} & \frac{(\gamma+b)(\gamma+5b)^2 A + (25b^2 + 27b\gamma + 5\gamma^2)[\gamma\,(\eta+m) - \kappa]\,b\,\eta}{5B(\gamma+b)(\gamma+5b)^2 + \gamma b \eta^2 (25b^2 + 27b\gamma + 5\gamma^2)} \\ & - \frac{(\gamma+4b)(\gamma+2b)\gamma\,a\,\eta}{5B(\gamma+b)(\gamma+5b)^2 + \gamma b \eta^2 (25b^2 + 27b\gamma + 5\gamma^2)} \end{aligned} \tag{A.15}$$

$$\begin{aligned} q_{sequential} = {} & \frac{\left[a\,(5B + \eta^2\gamma) - 5B(5bm + \kappa) - A\gamma\eta\right](\gamma+5b)\,(\gamma+b)}{5B(\gamma+b)(\gamma+5b)^2 + \gamma b \eta^2 (25b^2 + 27\gamma b + 5\gamma^2)} \\ & - \frac{\gamma\,b\,\eta^2\,m\,(25b^2 + 27\gamma b + 5\gamma^2)}{5B(\gamma+b)(\gamma+5b)^2 + \gamma b \eta^2 (25b^2 + 27\gamma b + 5\gamma^2)} \end{aligned} \tag{A.16}$$

In equilibrium, the pass-through effect is given as follows:

$$\frac{\partial P_{WS}(q_{sequential})}{\partial \kappa} = \frac{20bB\,(5b+\gamma)(b+\gamma)}{5B(b+\gamma)(5b+\gamma)^2 + b\eta^2\gamma(25b^2 + 27b\gamma + 5\gamma^2)}. \tag{A.17}$$

Comparing the pass-through effect in the sequential and simultaneous timing yields:

$$\begin{aligned} & \frac{\partial P_{WS}(q_{sequential})}{\partial \kappa} - \frac{\partial P_{WS}(q_{simultaneous})}{\partial \kappa} = \\ & \qquad \frac{12B\,b^3\eta^2\gamma^2}{\left[5B(b+\gamma)(5b+\gamma)^2 + b\eta^2\gamma(25b^2 + 27b\gamma + 5\gamma^2)\right](b\eta^2\gamma + 5Bb + B\gamma)} > 0. \end{aligned} \tag{A.18}$$

Appendix B IV Regression Results

Table B.1: Estimation of the Net Import Supply Function

	OLS	IV Regression	
		First	Second
	Q_t^{IM}	p_t^w	Q_t^{IM}
Pool Price	0.3401***	–	1.3764***
	(0.0632)		(0.2904)
Demand Forecast		74.0016***	
		(14.534)	
SK Import Cap.	0.4998***	-0.0181	0.5847***
	(0.1539)	(0.1125)	(0.1947)
BC-MT Import Cap.	0.4484***	-0.0302***	0.4825***
	(0.0358)	(0.0101)	(0.0369)
F-Stat	89.78***	–	–
K-P LM	–	25.92***	
Calendar Controls	Y	Y	Y
Temperature Controls	Y	Y	Y
Observations	8,782	8,782	8,782

Notes. OLS reflects the ordinary least-squares regression. First reflects the first-stage IV regression estimates for the endogenous variable p_t^w). Second reflects the second-stage net import supply function in (16). SK Import Cap. and BC-MT Import Cap. represent import transmission line capacities for Saskatchewan and the British Columbia-Montana interties, respectively. Standard errors in parenthesis are heteroskedastic-robust with 24 lags to control to autocorrelation. All regressions include the calendar and temperature controls detailed in Section 3.5. F-Stat denotes the F statistic for the OLS regression. K-P LM is the Kleibergen-Papp rk Lagrange-Multiplier test statistic for weak IVs. Statistical Significance $^{*}p < 0.10$, $^{**}p < 0.05$, and $^{***}p < 0.01$.

Appendix C Numerical Analysis

Subsection C.1 Descriptive Statistics

Table C.1: Wholesale and AS market parameters

Market Parameters	Mean	Std. Dev.
a	1,006.69	163.81
A	183.2	227.7
b	0.17	0.016
B	0.91	0.9
η	0.11	0.016

Table C.2: Firms' must-run capacity and cost parameters

Firm	Mean	Std. Dev.	Firm	Mean	Std. Dev.
Heartland			*Capital Power*		
m_1	455.45	75.79	m_2	344.23	20.49
κ_1	23.02	1.98	κ_2	17.79	2.02
γ_1	0.031	0.016	γ_2	0.018	0.003
ENMAX			*TransAlta*		
m_3	152.14	6.67	m_4	544.96	100.68
κ_3	11.41	1.59	κ_4	7.39	5.6
γ_3	0.02	0.001	γ_4	0.19	0.09

Subsection C.2 Numerical Results: Capital Power, ENMAX and TransAlta

Table C.3: Symmetric Firms - Capital Power Parameters

Panel (a)	$\overline{X}_{sim}$	$\overline{X}_{seq}$	$\% \Delta \overline{X}$	$\overline{P}_{AS,\,sim}$	$\overline{P}_{AS,\,seq}$	$\% \Delta \overline{P}_{AS}$	$\overline{TPC}_{AS,\,sim}$	$\overline{TPC}_{AS,\,seq}$	$\% \Delta \overline{TPC}_{AS}$
$\underline{\eta}$	163.11	158.52	-2.82	39.65	42.33	6.77	26,538.65	28,260.71	6.49
	(104.81)	(104.43)		(45.60)	(45.72)		(34,858.54)	(35,036.11)	
$\overline{\eta}$	123.95	91.00	-26.58	62.73	83.39	32.93	41,458.33	54,979.35	32.61
	(102.19)	(97.56)		(47.29)	(51.34)		(36,921.99)	(40,474.99)	
Panel (b)	$\overline{Q}_{sim}$	$\overline{Q}_{seq}$	$\% \Delta \overline{Q}$	$\overline{P}_{WS,\,sim}$	$\overline{P}_{WS,\,seq}$	$\% \Delta \overline{P}_{WS}$	$\overline{TPC}_{WS,\,sim}$	$\overline{TPC}_{WS,\,seq}$	$\% \Delta \overline{TPC}_{WS}$
$\underline{\eta}$	4,693.59	4,693.6	0.0003	227.711	227.709	-0.001	2,214,068.00	2,214,049.00	-0.001
	(697.25)	(697.25)		(35.00)	(35.00)		(500,455.8)	(500,452.2)	
$\overline{\eta}$	4,691.24	4,691.97	0.016	228.10	227.98	-0.05	2,217,938.00	2,216,752.00	-0.053
	(696.35)	(696.46)		(35.15)	(35.13)		(502,455.2)	(502,157.4)	

Table C.4: Symmetric Firms - ENMAX Parameters

Panel (a)	$\overline{X}_{sim}$	$\overline{X}_{seq}$	$\% \Delta \overline{X}$	$\overline{P}_{AS,\, sim}$	$\overline{P}_{AS,\, seq}$	$\% \Delta \overline{P}_{AS}$	$\overline{TPC}_{AS,\, sim}$	$\overline{TPC}_{AS,\, seq}$	$\% \Delta \overline{TPC}_{AS}$
$\underline{\eta}$	163.30	158.37	-3.02	39.56	42.45	7.30	26,478.60	28,323.73	6.97
	(104.92)	(104.75)		(45.61)	(45.72)		(34,857.14)	(35,034.34)	
$\overline{\eta}$	125.55	90.77	-27.71	62.01	84.06	35.56	40,943.35	55,299.68	35.06
	(103.10)	(99.00)		(47.41)	(51.71)		(36,898.8)	(40,524.77)	
Panel (b)	$\overline{Q}_{sim}$	$\overline{Q}_{seq}$	$\% \Delta \overline{Q}$	$\overline{P}_{WS,\, sim}$	$\overline{P}_{WS,\, seq}$	$\% \Delta \overline{P}_{WS}$	$\overline{TPC}_{WS,\, sim}$	$\overline{TPC}_{WS,\, seq}$	$\% \Delta \overline{TPC}_{WS}$
$\underline{\eta}$	4,697.46	4,697.48	0.0003	226.977	226.975	-0.001	2,207,481.00	2,207,460.00	-0.001
	(694.26)	(694.26)		(34.98)	(34.98)		(501,819.2)	(501,816.1)	
$\overline{\eta}$	4,694.94	4,695.77	0.02	227.39	227.26	-0.06	2,211,615.00	2,210,288.00	-0.06
	(693.26)	(693.38)		(35.13)	(35.12)		(503,872.5)	(503,591.3)	

Table C.5: Symmetric Firms - TransAlta Parameters

Panel (a)	$\overline{X}_{sim}$	$\overline{X}_{seq}$	$\% \Delta \overline{X}$	$\overline{P}_{AS,\, sim}$	$\overline{P}_{AS,\, seq}$	$\% \Delta \overline{P}_{AS}$	$\overline{TPC}_{AS,\, sim}$	$\overline{TPC}_{AS,\, seq}$	$\% \Delta \overline{TPC}_{AS}$
$\underline{\eta}$	152.15	142.35	-6.44	46.13	51.92	12.55	30,731.47	34,436.94	12.06
	(103.50)	(103.16)		(46.66)	(47.00)		(35,907.24)	(36,333.47)	
$\overline{\eta}$	61.67	33.71	-45.33	105.64	130.07	23.13	70,143.90	86,253.70	22.97
	(86.40)	(71.25)		(71.56)	(87.09)		(56,113.79)	(67071.07)	
Panel (b)	$\overline{Q}_{sim}$	$\overline{Q}_{seq}$	$\% \Delta \overline{Q}$	$\overline{P}_{WS,\, sim}$	$\overline{P}_{WS,\, seq}$	$\% \Delta \overline{P}_{WS}$	$\overline{TPC}_{WS,\, sim}$	$\overline{TPC}_{WS,\, seq}$	$\% \Delta \overline{TPC}_{WS}$
$\underline{\eta}$	4,352.86	4,353.04	0.004	284.15	284.12	-0.01	2,767,747.00	2,767,451.00	-0.01
	(632.13)	(632.15)		(59.79)	(59.77)		(761,465.6)	(761,323.6)	
$\overline{\eta}$	4,346.28	4,350.51	0.10	285.25	284.54	-0.25	2,778,704.00	2,771,751.00	-0.25
	(629.36)	(630.06)		(60.28)	(60.12)		(768,917.4)	(766,535.4)	

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