UNIVERSITY OF ALBERTA
FACULTY OF ARTS
Department of Economics

Working Paper No. 2019-09

Pricing Patterns in Wholesale Electricity Markets: Unilateral Market Power or Coordinated Behavior?

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June 2019

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by

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Abstract

We examine allegations that firms in Alberta's electricity industry manipulated public information to coordinate in the wholesale market. We investigate whether bids by firms who employed unique pricing patterns were consistent with unilateral expected profit maximization. Our results suggest that these firms could have increased expected profits through unilateral deviations. For one firm, the potential to increase profits is greater on days when certain offer patterns are observed, providing support for the claim that such patterns may have assisted coordination on high-priced outcomes. These results suggest that regulators should exercise caution when designing information disclosure policies in concentrated electricity markets.

Keywords: Electricity, Market Power, Information, Regulation, Antitrust
JEL Codes: D43, L40, L51, L94, Q48

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Acknowledgements. This research project received support from the Government of Canada's *Canada First Research Excellence Fund* under the Future Energy Systems Research Initiative. The authors thank David Benatia, Jeffrey Church, Derek Olmstead, Mar Reguant, Mario Samano, David Sappington, Bert Willems and seminar participants at the University of Florida, the 42nd Annual International Association for Energy Economists Conference, and the 53rd Annual Canadian Economics Association Conference for helpful comments and suggestions.

1 Introduction

Suspicions of coordinated behaviour may arise when firms are observed behaving in conspicuous ways that could be designed to communicate with rivals. Indeed, screens that have been employed by or recommended to antitrust agencies to identify possible coordination have looked at price uniformity and rigidity as well pricing anomalies observed in settings where coordination is suspected; see for example Abrantes-Metz and Bajari (2009). Unfortunately, the observation of anomalous behaviour observed among certain firms is insufficient to conclude that coordination to increase profits above non-cooperative levels is taking place.[1]

A recent example highlighting these concerns involves the wholesale electricity market in Alberta. In this market, firms submit multiple price-quantity offer blocks for each generating asset for each hour of the day, and can adjust their offers up to two hours before the market clears. The system operator that coordinates the operation of the market dispatches these blocks throughout the hour in increasing order of price to clear the market. Until recently, the complete list of price-quantity offers was made public approximately ten minutes after the hour ended, but with generator and firm identifiers removed, through the Historical Trading Report (HTR).[2] In 2013, Alberta's Market Surveillance Administrator (MSA), which is responsible for monitoring competitive behaviour in the province's electricity industry, issued a report alleging that certain large firms were using the HTR to elevate market prices on certain days (MSA, 2013a). These concerns led to a hearing of the Alberta Utilities Commission (AUC) in 2017, which ordered the system operator to cease publication of the HTR (AUC, 2017).

Part of the MSA's concern was the allegation that firms were "tagging" offers, or employing certain patterns (not documented by the MSA) in offer prices, in order to reveal their identities through the HTR and to send messages. In particular, the MSA alleged that on certain days, firms had increased offer prices on certain generating assets, and "tagged" those offers to indicate an intent to maintain these blocks at high prices in subsequent hours, allowing other firms to increase their own offers without fear of being undercut. These claims were supported through description of ten days, drawn from several years, on which they believed the alleged behaviour occurred.

The MSA's claims that "tagging" patterns could identify firms through their offers in the HTR are substantiated in Brown et al. (2018a). As an illustration, Figure 1 plots the price endings of all non-zero offers by TransCanada, a large firm in Alberta's wholesale electricity market, from January to June 2012. From approximately May 2010 to August 2013, price endings by this firm followed a seven day pattern. On each day, each price ending would be a base ending plus different multiples of 0.09. On the first day of the month the base ending would be 0.06, on the second day 0.07, and so forth. On the eighth day the base price would be reduced back to 0.06 and the

[1] See for example Harrington (2008) for further discussion.

[2] Similar levels of information disclosure are made available in other electricity markets. For example, in Australia and New Zealand firms' unit-specific offers are made available at a one-day and two-week lag with firm identifiers, respectively (EMA, 2014).

pattern would continue. Brown et al. (2018a) demonstrate that TransCanada's offers could be accurately identified from the HTR through knowledge of this pattern.

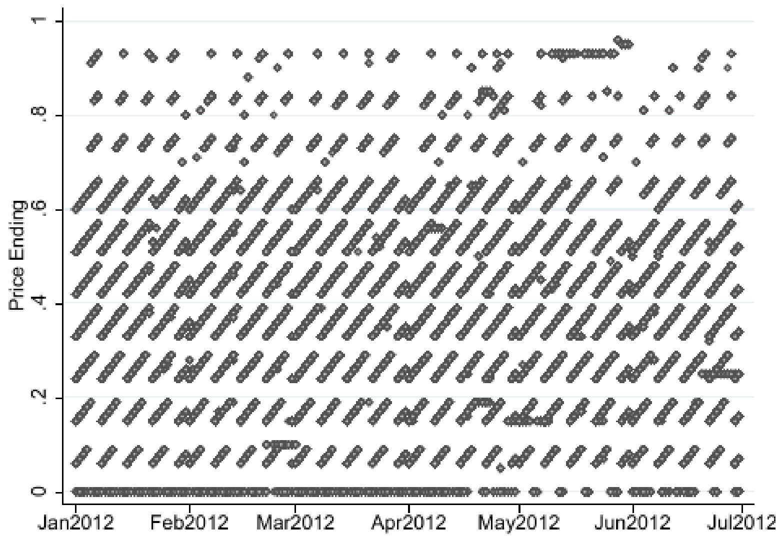


Figure 1: TransCanada's Daily Price Endings: January - June 2012

However, the observation of such unique patterns in the prices of firms does not necessarily indicate that the patterns are being used to coordinate at supra-noncooperative outcomes. For example, it has been suggested to the authors in conversations with industry participants that price offers for certain firms may employ patterns to allow them to quickly identify their *own* offers in public real-time data. Alternatively, patterns in prices submitted by individual employees may exhibit patterns for personal reasons (for example, boredom), and are unintended to have effects on market outcomes. Further, as discussed in Brown et al. (2018a), in games that exhibit multiple equilibria, coordination may be intended to identify a particular non-cooperative equilibrium.[3]

In the current paper, we build on the existing literature to develop an empirical methodology to examine whether observed offer behaviour was consistent with firms unilaterally maximizing expected wholesale (spot) market profits, given the bidding behaviour of rival firms. We focus on two large firms (TransCanada and Capital Power) that are demonstrated in Brown et al. (2018a) to have used patterns in their offers. First, we estimate each firm's expected spot profits from observed offer behaviour using a Monte Carlo simulation approach to account for uncertainty in market-level demand and wind output. Second, we estimate the firms' expected spot market profits from alternative counterfactual offer curves. Third, we compare the expected profit levels from the observed and counterfactual offer curves, including estimates of ramping and unit start-up costs to account for important dynamic costs. This approach allows us to investigate whether firms were behaving in a manner consistent with expected profit maximization given rival offer behaviour,

[3]See for example Bolle (1992) for a general discussion, and Baziliauskas et al. (2011) for a discussion of this possibility in the Alberta context.

and if the results depend on whether tagging patterns were employed by Capital Power, who only employs its pattern on certain days.

We illustrate that when Capital Power employed its unique offer pattern, it priced-out several of its units at high prices and held these offers throughout the day. TransCanada systematically adjusted its offers on several of its units upward under the high-priced shelf established by Capital Power. Our analysis finds that these two large firms could have increased their expected profits through unilaterally deviating from their observed offers. For Capital Power, the magnitude of these expected gains are particularly pronounced on days where it is employing its unique offer pattern. The expected profit gains in these hours reflect up to an 18.5% increase in its hourly average expected profits. Further, we demonstrate that this firm could have utilized a simple unilateral deviation strategy that involved it pricing-down its generation units to achieve these sizable expected profit gains. We show that the foregone expected profits cannot be explained by dynamic considerations such as start-up costs.

We investigate the behaviour of another large firm (ATCO) who is not observed to submit any distinct offer patterns, but adjusted its offers on days when Capital Power's unique offer pattern was utilized. Unlike the other two firms, we demonstrate that this firm's behaviour was consistent with unilateral expected profit maximization.

Our findings provide support for the claim that tagging patterns may have played a role in coordinating on high-priced outcomes. Further, our results are consistent with a firm utilizing a unique offer pattern to take a leadership role to increase prices in certain hours. These results suggest that regulators should exercise caution when undertaking policies that increase information disclosure in concentrated electricity markets where firms interact repeatedly. These findings have important policy implications in the face of recent legislation to increase information disclosure and market transparency in European electricity markets (von der Fehr, 2013; EU; 2013).

This paper will proceed as follows. Section 2 surveys the relevant literature. Section 3 provides background on the wholesale electricity market in Alberta, as well as the HTR and associated AUC hearing. Data used in our analysis are described in Section 4. Section 5 provides a more detailed overview of the offer behaviour and pricing patterns of our two firms of focus. Our empirical methodology is described in Section 6. Results are presented in Section 7. Section 8 concludes.

2 Related Literature

Our paper contributes to the literature regarding the effects of market transparency in electricity markets. In a static oligopoly setting with non-cooperative firms, existing literature suggest that information enhances market competition (Kuhn and Vives (1994), Vives (2011), and Holmberg and Wolak (2018)).[4] Alternatively, in a setting where agents interact repeatedly, it has been argued that information can help facilitate coordination (e.g., Stigler, 1964; von der Fehr, 2013).

[4]An exception to this conclusion is Hefti et al.'s (2019) analysis which presents experimental evidence that increased information elevates prices in a multi-unit auction environment.

While collusion in electricity markets has been examined in theoretical models (e.g., Fabra (2003); Dechenaux and Kovenock (2007)), there is limited empirical evidence of coordinated behaviour in electricity markets. Two exceptions are Macatangay (2002) in England and Wales and Fabra and Toro (2005) in Spain. However, these papers do not investigate the role of market transparency and/or communication in firms' abilities to coordinate on high-priced outcomes. To the best of our knowledge, our paper is the first empirical analysis to illustrate the potential role of pricing patterns on coordinated behaviour in multi-unit procurement auctions.[5]

Brown et al. (2018a) study the use of the HTR in Alberta, and demonstrate that over the period from 2011 to 2013, certain large firms employed patterns in their offers that could reveal their identities through the HTR, that firms appear to respond to information in the HTR, and that they respond differently to the offers of different rivals, which suggests that they are able to identify rivals from their offers.[6] In contrast to Brown et al. (2018a), the focus in this paper is on whether the offers of these firms represent non-cooperative behaviour (as might be expected if the goal of tagging was to coordinate in a multiple-equilibrium setting or to identify their own offers), or whether firms were using offer patterns to coordinate on high-priced outcomes.

As a result, our paper is closely related to the empirical literature that tests whether electricity generators' behaviour is consistent with non-cooperative behaviour in wholesale markets. Key contributions in this literature include Wolak (2000, 2003, 2007), Sweeting (2007), Hortaçsu and Puller (2008), and Hortaçsu et al. (2019). Broadly, these papers test whether firms submit bids that are unilateral best responses to those submitted by rivals. Our empirical methodology, described in more detail below, employs features of these studies to test if firms are behaving in a way that is consistent with unilateral expected profit maximization, and if this effect varies by whether or not firms were employing their unique offer patterns.

Wolak (2000, 2003, 2007) establish a structural approach to investigate behaviour in Australia and California. The author's studies find that firms bidding behaviour is consistent with unilateral expected profit maximization. Hortaçsu and Puller (2008) utilize an alternative structural approach to investigate bidding behaviour in Texas and find that large firms behave in a manner that is consistent with unilateral expected profit-maximization, while small firms do not. Hortaçsu et al. (2019) extend this work by demonstrating that this sub-optimal behaviour by small firms can be explained by bounded rationality and a lack of overall strategic sophistication.

Sweeting (2007) analyzes firm behaviour in England and Wales in the 1990s. The author compares a generator's realized profits with those that could be earned from specific counterfactual offers, given realized demand and rival offers. The author finds that the two largest generators could have increased profits by lowering bids. This is taken as consistent either with collusion, or

[5]There exists an experimental literature on the role of communication in facilitating collusion in multi-unit auctions; see Kwasnica and Sherstyuk (2013) for a survey.

[6]Our paper is also related to the large literature that documents and investigates pricing patterns that may be utilized to facilitate coordination in other industries such as airlines (Borenstein, 1998) and retail gasoline (Lewis, 2015). See Brown et al. (2018a) for a detailed review of this literature.

with an attempt by the firm to raise prices for hedging contracts.

Finally, in a report written for the Alberta Electric System Operator (AESO) that is directly related to our paper, Wolak (2014) considers the relationship between wholesale spot market prices in Alberta and the inverse elasticities of residual demand faced by the five largest firms, using data from 2009 to 2013. The author finds that higher prices are associated with higher inverse semi-elasticities, which is taken to be consistent with unilateral profit maximization. This analysis makes no distinction between days in which the offer patterns of concern were employed. In contrast, our analysis compares the expected profitability of observed offer curves to specific counterfactuals motivated by the MSA's complaint (MSA, 2013a), and considers whether the difference between observed and counterfactual offer curves is different on tagging days.

3 Background

3.1 Alberta's Wholesale Electricity Market

Alberta's wholesale electricity market operates as an hourly uniform-price procurement auction. For each generating asset it controls, a firm may submit up to seven price-quantity offer blocks, representing the minimum price at which they would be willing to supply the specified quantity. Prices must lie between \$0 and \$999.99/MWh, and all available capacity must be offered.

For each hour, the offer blocks are sorted in increasing order of price, to create a merit order. Market-clearing is facilitated by a system operator. Throughout each hour, the system operator calls upon generating assets to supply electricity in increasing order of offer prices until market demand is met. The offer price of the last block called upon sets the system marginal price (SMP). At the end of the hour, each generating unit that was dispatched during the hour is paid according to the pool price of the hour, which is the time-weighted SMP for the hour.

Alberta's market currently operates as an energy-only design where firms rely solely on revenues from the wholesale market (and ancillary service markets) to recover both variable and fixed costs.[7] To ensure that the fixed costs of capacity investments are recovered, Alberta's market explicitly permits unilateral market power (MSA, 2011) and employs no bid-mitigation to restrict markups over marginal cost. Historically, Alberta's wholesale market has exhibited substantial market power in high demand hours (Brown and Olmstead, 2017).

Production capacity was moderately concentrated with the five largest firms having offer control over approximately 64% of generation capacity during our sample period, while a competitive fringe of over thirty firms owned the remaining capacity. In 2013, the five large firms' market shares of capacity were approximately 10%, 10%, 13%, 13%, and 18% for ATCO, Capital Power, ENMAX, TransAlta, and TransCanada, respectively (MSA, 2013b). In Alberta, the dominant technologies are coal and natural gas. For example, in 2013 coal, natural gas, wind, and hydro represented

[7] In November 2016, the Alberta government announced that the market will be transitioning from an energy-only to a capacity market design that provides separate payments to generators for their generation capacity. For additional details, see AESO (2016).

43%, 40%, 8%, and 6% of generation capacity, respectively (AUC, 2013). An important and unique aspect of Alberta's electricity market is the high proportion of generation that comes in the form of cogeneration (i.e., 30% of market capacity and the majority of natural gas capacity in 2013). Cogeneration facilities generate electricity as a by-product of an on-site industrial process (e.g., oil-sands). As a result, this electricity is systematically priced-in at $0/MWh.

3.2 Historical Trading Report

In August 2013, the Alberta Market Surveillance Administrator issued a report alleging that certain firms were manipulating public information on near-real-time offers to increase prices in certain hours (MSA, 2013a).[8] In particular, the MSA argued that these firms were "tagging" their price-quantity offers through certain price endings or other patterns; these tagged offers, without identifying information, would be released 10 minutes after an hour through the Historical Trading Report. Since firms can adust offer prices up to two hours before an hour, the HTR was alleged to allow firms to communicate within a short time frame to affect prices on high demand days.

These allegations led to a hearing of the AUC, which decided in May 2017 that the AESO must cease publication of the HTR (AUC, 2017). While the AUC decided that the HTR could potentially lead to coordinated behaviour, it did not rule on whether that had actually occurred. Importantly, the focus of empirical analysis in the hearing was not on whether firms were behaving in coordination, but on the net average effect of the release of the HTR, comparing observed prices to hypotheticals meant to represent conduct in the absence of the HTR.[9]

Patterns in offer curves that may have served to reveal the identity of the firm are documented in Brown et al. (2018a). In particular, two large firms (TransCanada and Capital Power) are shown to apply patterns to their offer prices that would allow rivals to identify them and could potentially be used to convey other information. TransCanada's pattern, which was employed in almost all hours from May 2010 until August 2013, involved ending offer prices with a restricted set of numbers that differed by multiples of nine cents, and that shifted in a weekly pattern (recall Figure 1). In contrast, Capital Power's pattern was restricted to certain days and high-priced offers, and involved sequences of offers separated by exactly one dollar.[10] It was argued in MSA (2013a) that such a pattern could be used on days with a high potential for market power to signal to rivals that the firm wished to elevate prices, and would keep these blocks priced up out of the market for the duration of the day. More details on the offer behaviour of Capital Power and TransCanada are given in Section 5 below.

While such patterns are suggestive, it has not been demonstrated whether this behaviour was indeed used to sustain profits (at least on certain days) that exceed those associated with

[8] See Brown et al. (2018a) for an extended discussion of the HTR and the MSA's allegations.

[9] See for example Church (2016) for a discussion of counterfactuals presented by the MSA and ENMAX.

[10] Other patterns have been identified in Capital Power's offers for some hours; see Lin (2016). In our analysis, we focus on the pattern with sequences of integers described above because it corresponds with the claims of tagging in the MSA (2013a) examples, and because other patterns are mainly observed in low-priced offers.

unilateral profit-maximizing behaviour. Communication between firms could be used to select a specific non-cooperative equilibrium in a setting in which multiple equilibria exist (e.g., Bolle (1992)). Alternatively, communication could be used to coordinate on an outcome more profitable than the non-cooperative equilibrium, in which case firms could potentially increase profits through unilateral deviations. This question is the focus of the current paper.

4 Data

We utilize publicly available data from the AESO that consists of hourly offer price and quantities for each firm and generation asset, import supply and inter-tie capacity, wind output, and market demand for the year 2013. We restrict attention to 2013 because prior to 2013, the AESO did not provide full information on the firm offering each price-quantity block, and because the MSA's (2013a) report on tagging through the HTR was released in August 2013.

We supplement the AESO's data with price and quantity offers reported in the HTR from January to June 2013, provided to us by the Alberta MSA.[11] This data set reports for each hour the initial offer price and quantity of each block submitted by noon the day before the hour, and the final (restated) price and quantity of each block. The HTR data provided to us are enhanced beyond what is available to the firms immediately after each hour, as the data provided by the MSA identify the firm and asset offering each price-quantity block. These data allow us to identify changes to a firm's offer curve that are made after noon on the day before the hour. This provides insight into the way firms adjusted their offers in near-real time providing direction for the types of offer adjustments and counterfactuals we consider in our subsequent analysis.

5 Bidding Behaviour and Capital Power's Pricing Pattern

As noted above, previous research has highlighted that two firms, Capital Power and TransCanada, employed unique offer patterns. While TransCanada's pattern was observed in nearly every hour, Capital Power only employed its offer pattern in certain selective periods. Our analysis will focus on investigating Capital Power's unique offer pattern and firms' bidding behaviour on days where the bidding pattern is and is not employed.

5.1 Capital Power's Offer Behaviour

Capital Power employs a unique bidding pattern on a subset of days where it submits a sequence of at least four blocks at prices, typically above \$900/MWh, spaced exactly \$1/MWh apart and with price-endings of .00. This tagging pattern is utilized in at least one hour on forty-seven days in our sample (reflecting 13% of days). The assets that employ this bidding pattern are Capital Power's peaker natural gas units in 78% of the cases, while the remaining cases reflect a portion of its coal assets. When the tagged assets are natural gas units, the entire units are "priced-out" and not providing any electricity. Alternatively, when the tagged assets are coal units, these units are

[11] The HTR data are unavailable past June 2013.

supplying output from a portion of the plants' capacities (reflecting minimum stable generation requirements), while a portion of the asset is tagged and "priced-out".[12]

Table 1: Capital Power's Offers: March 6 2013, HE 18

Asset Id	Block Number	Price	Available MWhs	Dispatched MWhs
SD6	0	0.00	150	150
SD5	0	0.00	150	150
GN1	3	10.75	9	9
GN2	3	10.76	9	9
GN3	2	333.33	55	55
GN3	3	414.44	50	50
GN3	4	725.00	40	40
GN1	6	740.00	10	10
GN2	6	741.00	10	10
ENC1	5	974.00	43	0
ENC3	3	975.00	70	0
ENC3	4	976.00	27	0
ENC2	4	977.00	70	0
ENC2	5	978.00	27	0
SD5	2	979.00	123	0
SD6	2	980.00	127	0
SD6	3	999.98	70	0

Table 1 presents an example of Capital Power's tagging pattern. In hour-ending (HE) 18 (i.e. 6:00 PM) of March 6, 2013, Capital Power offered 487 MWhs from gas units Cloverbar 1, 2 and 3 (ENC1, ENC2, and ENC3) and coal units Sundance 5 and 6 (SD5 and SD6) at prices from $974 to $980 that are evenly spaced by $1. While none of these tagged offers are called upon to supply in this hour, coal assets SD5 and SD6 are producing positive output at $0/MWh offers.

When Capital Power employs this bidding strategy, it employs the tagging strategy for at least 12 hours of the day in 53% of tagging days. Further, Capital Power begins the tagging pattern between the late evening and early morning hours (i.e., between HE 23 - HE 6) 59% of the time and holds the tagging pattern throughout the majority of the day.

Figure 2 presents Capital Power's cumulative offer curves when it does and does not employ its unique offer pattern. When Capital Power's offer pattern is employed, it systematically offers in a larger portion of its assets at high-offer prices (above $900/MWh). Consequently, Capital Power's cumulative offer curve is shifted downward substantially in hours with the unique offer pattern.

Figure 3 illustrates how Capital Power's offer curve changes when it is and is not employing its unique offer pattern. When its offer pattern is employed, Capital Power establishes a large high-priced offer shelf with its tagged units. These units are systematically not called upon to supply electricity (in less than 3% of hours). The tagged high-priced shelf has important implications on

[12] More specifically, Capital Power employs its tag on three coal units: GN3, SD5, and SD6. When the unique offer pattern is employed on these units, the "priced-out" blocks reflects an average of 21%, 26%, and 35% and a maximum of 22%, 58%, and 58% of the GN3, SD5, and SD6 units' capacities, respectively.

Figure 2: Capital Power MWh-Weighted Cumulative Offer Curves by Offer Pattern

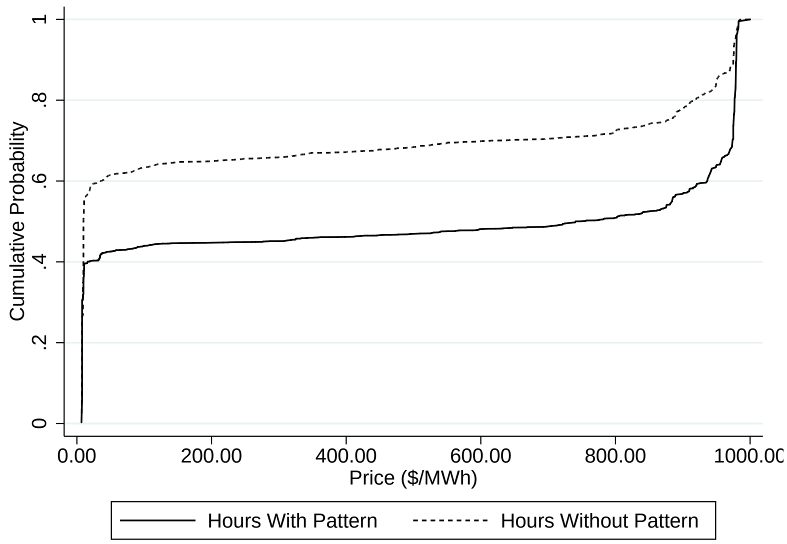
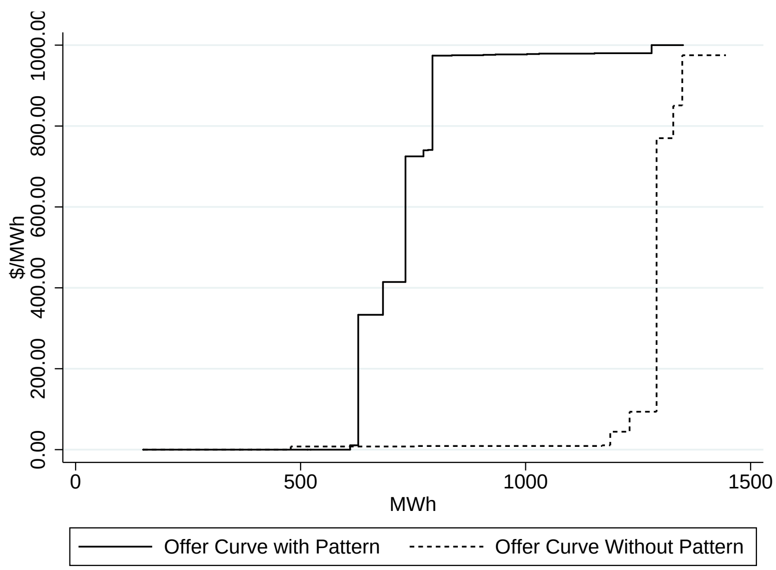


Figure 3: Representative Capital Power Offer Curves by Offer Pattern, March 6 HE 18 (With) and March 29 HE 18 (Without)

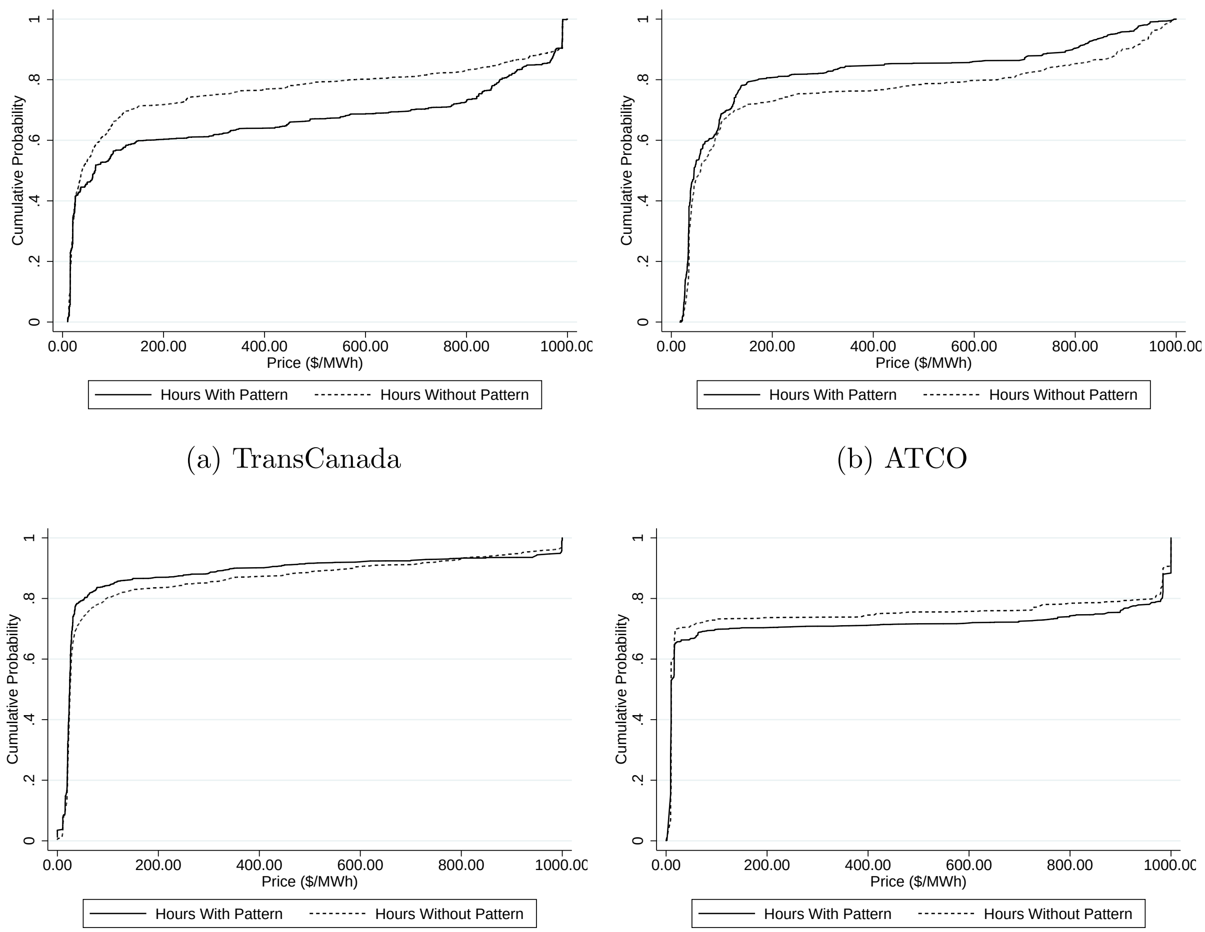


market outcomes because it induces its rivals to face a residual demand function that is highly price-inelastic at moderate to low prices. This creates incentives for increased market power execution. Alternatively, on days where Capital Power is not employing its offer pattern, these units are systematically offered at low prices and dispatched to supply energy.

5.2 Rival Offer Behaviour

We now investigate how Capital Power's rivals' offer behaviour varies on days when Capital Power does and does not employ its unique offer pattern. Figure 4 illustrates the cumulative offer curves of TransCanada, ATCO, ENMAX, and TransAlta on days where Capital Power does and does not employ its unique offer pattern. These cumulative offer curves demonstrate broad patterns in the firms' offer behaviour. ENMAX and TransAlta submit stable offer curves that do not seem to be associated with whether or not Capital Power is employing its unique offer pattern. ATCO submits stable low-priced bids on its cogeneration facilities, but often prices out its peaker natural gas units at high prices (above $900/MWh). On days where prices were observed to be high (i.e., above the 75th percentile), ATCO prices down its peaker natural gas units.

Figure 4: MWh-Weighted Cumulative Rival Offer Curves by Capital Power Offer Pattern



(a) TransCanada

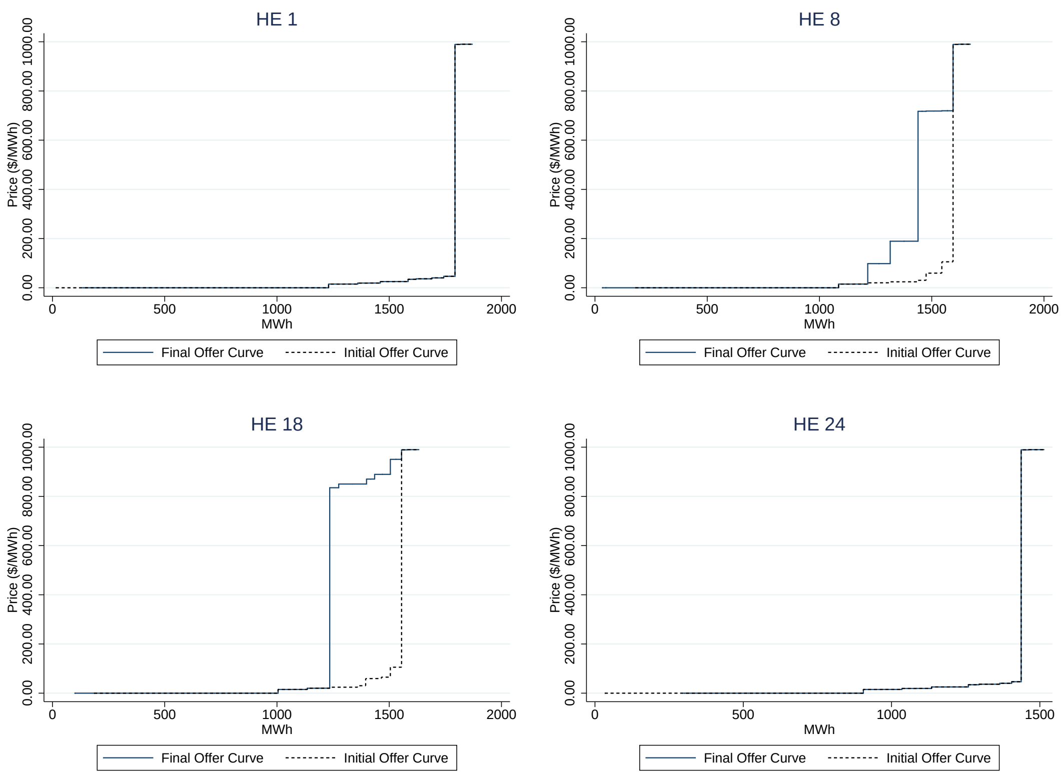
(b) ATCO

(c) ENMAX

(d) TransAlta

Alternatively, Transcanada's offer behaviour differs on tagged and non-tagged days. To understand this behaviour further, we utilize the HTR data set which covers all hours between January 1st and June 31st to investigate TransCanada's initial and final offer curves. Recall, firms are able to adjust their offer behaviour up to two hours in advance of market clearing and the HTR data set includes all initial and final offers. In these data, TransCanada often submits an initial offer curve that reflects low offer prices and on certain days it restates its bids on several units upwards above $100/MWh. More specifically, 86% of TransCanada's on-peak hour bids between

Figure 5: TransCanada Initial and Final Offer Curve, March 8, 2013



$100/MWh and $980/MWh reflect such bid restatements in the HTR data.[13] Further, nearly all of these bid restatements (98.9%) entail TransCanada pricing up a portion of one of its coal assets, with two coal assets reflecting approximately 78% of these cases.

Figure 5 provides an illustrative example of the dynamics of TransCanada's offer behaviour on a day in which Capital Power was employing its unique offer pattern throughout the entire day, establishing a high-priced shelf between $974/MWh to $980/MWh consisting of 467 MWhs. In the early morning, TransCanada is pricing in the majority of its units at low prices reflecting its initial offer curve. By HE 8, TransCanada has priced up a portion of several coal units at moderate to high prices. By early evening (HE 18), TransCanada has priced up 320 MWhs between $835 and $950 below Capital Power's shelf beginning at $974/MWh. At the end of the day (HE 24), TransCanada units are priced at low offers reflecting the initial offer prices. On this day, the market-clearing price ranged from $26/MWh to $850/MWh reaching the maximum at HE 22.

The example in Figure 5 demonstrates TransCanada's bidding strategy throughout our sample period. TransCanada employs this strategy on both tagging and non-tagging days with the common characteristic that it does so on days where the market is tight (i.e., there is limited generation capacity that is not being utilized). TransCanada also employs this strategy on 85% of

[13] TransCanada's offers exceeding $980/MWh reflect less than 5% of its bids. Further, the majority of these bids (93%) reflect TransCanada pricing its small cogeneration units at prices that ensure they will not be called up to supply electricity due to on-site operating restrictions.

days where Capital Power is using its unique offer pattern for at least one hour in the day.

It is important to note that this bidding behaviour is not consistent with TransCanada pricing out its coal assets to avoid dynamic start-up or ramping/cycling costs associated with its relatively inflexible coal power plants for several reasons. First, these coal assets are operating at a positive level of output as a sizable proportion of the assets' capacities (35% - 74%) are offering in at a price of $0/MWh to ensure they are (partially) called upon to supply electricity. Second, if TransCanada were pricing out these assets, we would expect to see TransCanada elevating the bids of these assets overnight, while reducing its bids during the day when prices are systematically higher and the start-up costs are more likely to be recovered. Third, we observe that the high-priced portion of these coal units are called upon to supply electricity in certain high-priced hours.

Overall, our discussion in this section shows that on certain days Capital Power submits a unique offer pattern and establishes a sizable high-priced shelf, often in the late evening or early morning hours, on a portion of its offer curve that is not likely to intersect market demand (i.e., on units that are extra-marginal) and holds these prices constant throughout the day. In subsequent hours, this behaviour is observed in the de-identified HTR data by rival firms. Further, we describe systematic behaviour by TransCanada in the subsequent on-peak hours where TransCanada begins to price up its coal assets in the early morning hours, eventually pricing portions of several of its large coal units up under the high-priced shelf that was established by Capital Power.

While these are observations are suggestive, it remains to consider whether the conduct described above is consistent with non-cooperative behaviour. In the next section, we will discuss our empirical strategy to test this question.

6 Empirical Methodology

Our primary objective is this paper to empirically evaluate whether firms' bidding behaviour was consistent with static (unilateral) expected profit-maximization. Our analysis focuses on two of the five largest firms, Capital Power and TransCanada, for several reasons in addition to the results presented in the previous section. First, MSA's (2013a) report focused on the conduct of three specific firms: ATCO, Capital Power, and TransCanada. Second, Brown et al. (2018a) identify patterns in the offers of two of these firms (Capital Power and TransCanada). Third, we exclude ENMAX because it is vertically integrated as a generator and retailer, giving it less incentive to increase market power.[14] Fourth, TransAlta and ENMAX systematically submit bids for their assets at or near their short-run marginal cost (or $0/MWh).

Fifth, approximately 44% of TransAlta's capacity is hydro generation that is subject to long-term forward contracts mandated during the restructuring of the market (MSA, 2012). In combination with the fact that minimum stable generation on coal assets and cogeneration, less than 20% of TransAlta's generation is considered to be flexible. As a result, TransAlta has limited

[14]Bushnell et al. (2008) demonstrates that vertically integrated firms have less incentive to exercise market power in the wholesale market. See Brown and Eckert (2018) for a detailed discussion in the Alberta context.

incentive and ability to exercise market power. Finally, the vast majority of ATCO's capacity is in the form of cogeneration units that typically offer power into the market at a price of zero; as an extension, however, Section 7.3.4 investigates the behaviour of ATCO who is the only remaining large firm that consistently altered its offer behaviour on tagged days.

Our analysis employs the following empirical strategy. First, it is important to account for the presence of uncertainty in wholesale demand and wind output when firms formulate their bidding behaviour. Consequently, we establish an empirical model to forecast hourly demand and wind in order to compute the estimated level of net demand (demand minus wind output) and the distribution of its residuals to capture market uncertainty facing the firms.

Second, for each hour, we construct a firm's residual demand curve by taking the estimated net market demand level and subtracting a firm's rivals observed offers to establish a downward sloping residual demand function. To account for the presence of demand and wind output uncertainty, we undertake a Monte Carlo simulation that randomly draws 1000 values from the estimated residual distribution of net market demand. This establishes a distribution of net market demand point estimates and consequently, residual demand functions that a firm could face in any given hour.

Third, facing the estimated distribution of residual demand functions, we estimate a firms' expected profit and the distribution of market-clearing prices from employing its observed offer strategy. Fourth, we construct an array of counterfactual offer curves for both Capital Power and TransCanada to investigate if either firm could have employed an alternative offer strategy to elevate its expected profits, and whether the profitability of unilateral deviation was greater on days in which Capital Power was employing its unique tagging strategy.

Note that, in contrast to Hortaçsu and Puller (2008), we do not construct profit maximizing best response functions for each firm. In our setting, residual demand curves are highly non-linear, and typically exhibit an elastic portion at high prices, a sharply inelastic segment, and then high elasticity again at low prices. As a result, profit functions can have multiple local maxima, which can result in offer curves following the methodology of Hortaçsu and Puller (2008) that are not monotonically increasing. Our methodology is closest to the approach utilized in Sweeting (2007).

Our analysis focuses on the hours between 11:00 AM and 10:00 PM (HE 12 - 22). These on-peak hours reflect the hours where the price and demand is highest in our sample. This captures the hours where firms have been observed to exercise market power in Alberta (Brown and Olmstead, 2017). We focus on the wholesale market, and do not consider bidding behaviour in or the provision of services in ancillary service markets (such as the provision of reserve products). Capital Power is observed to offer supply into ancillary service (AS) markets.[15] However, in the dataset, quantities that are dispatched in the AS market are removed from Capital Power's offers for the relevant assets ensuring that our results are not impacted by the multi-market features of electricity.

[15]For example, from January to March 2013, Capital Power's coal unit SD5 is dispatched in AS markets in 313 hours, at an average of 55 MWh; its other assets were dispatched less frequently and in smaller amounts.

6.1 Net Market Demand Estimation

When firms formulate their bidding decisions, they form expectations about their rivals' bidding behaviour, the level of market demand, output from rival firms' wind facilities, and output from their own wind facilities. In Alberta's wholesale market, wind is priced in at \$0/MWh to ensure that it is always called upon to supply electricity. As a result, a key component of a firm's bidding decision is the level of market demand net of rival wind output that is always utilized to supply electricity. Firms face uncertainty in both the level of demand and wind output. We use the following model to estimate the net demand level and uncertainty facing firm $i \in \{\text{Capital Power, TransCanada}\}$ in any given hour t:[16]

$$\text{Net Demand}_{i,t} = \beta_{0,i} + \beta_{1,i}\,\text{Net Demand}_{i,t-4} + \beta_{2,i}\,\text{Net Demand}_{i,t-24} + \beta_{3,i}\,\text{Net Day-Ahead Forecast}_{i,t} + \sum_{j=1}^{24} \alpha_{j,i}\, Hour_j + \sum_{j=1}^{12} \omega_{j,i}\, Month_j + \epsilon_{i,t} \quad (1)$$

where Net Demand$_t$ reflects perfectly price-inelastic wholesale market demand minus rivals' wind output in period t, Net Demand$_{t-4}$ and Net Demand$_{t-24}$ reflect four and twenty-four hour lagged net demand, Net Day-Ahead Forecast$_t$ is the day-ahead forecast of market demand minus the day-ahead forecasted wind output for hour t, $Hour_j$ and $Month_j$ are hour and month fixed-effects to capture hourly and seasonal variation in net market demand, and ϵ_t is the stochastic residuals.[17,18]

Our empirical model estimates net demand levels well with an R-squared value of 0.93 and 0.92 for Capital Power and TransCanada, respectively. Figure 6 presents the distribution of the error terms resulting from these regression analyses with an overlaid normal distribution. These figures demonstrate that the uncertainty in the net demand levels can be approximated well with normal distributions of mean zero and standard deviations of 203.87 and 200.11 for TransCanada and Capital Power, respectively.[19] As discussed in more detail below, we will utilize the estimated net demand levels and the observation that the uncertainty in net demand can be approximated well by a normal distribution in our subsequent Monte Carlo simulations to estimate a firm's expected profit from employing a particular bidding strategy.

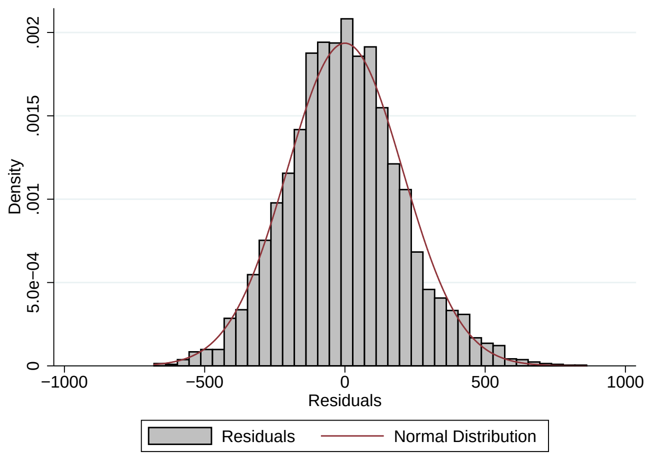
[16] We estimate separate net demand functions for both firms because Capital Power had one wind generation facility with a maximum capacity of 150 MWs and average output of 53 MWhs. Uncertainty in Capital Power's own wind resource complicates the analysis because this induces uncertainty in both its residual demand (via net demand) and its own cost function and resource availability. For analytical simplicity, we assume that Capital Power knows its level of wind output with certainty. As a result, for Capital Power's net demand function we do not subtract its own wind output. We anticipate that this will have a small impact on our analysis because wind output represents approximately 4% of Capital Power's average observed output.

[17] In Alberta, the majority of consumers face time-invariant retail tariffs. In Section 7.3.2, we demonstrate that our results are robust to the consideration of price-responsive load in the wholesale market.

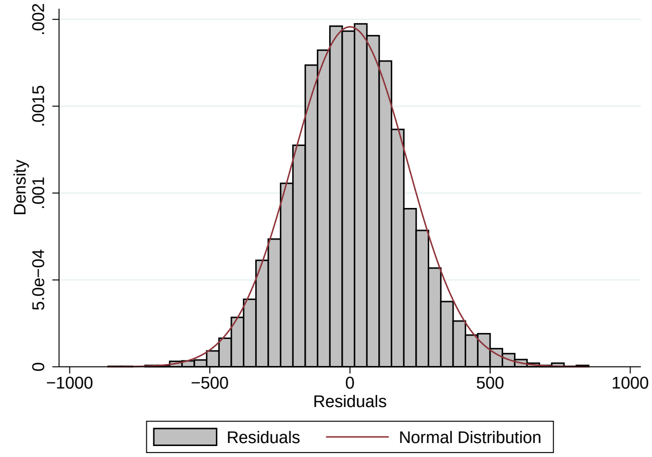
[18] We include four-hour lagged net demand because firms are able to adjust their offer behaviour four hours in advance of market-clearing based on new market-level information (Brown et al., 2018a). However, the results of our estimation are consistent when we chose different lagged net demand structures.

[19] For detailed results, see Table A3 in the Appendix.

Figure 6: Net Demand Residual Distributions



(a) Capital Power



(b) TransCanada

6.2 Marginal Cost Estimation

We estimate the marginal cost of fossil-fuel assets offered using the typical engineering formula. A thermal unit's constant marginal cost of production up to its maximum capacity c_{it} equals:

$$c_{it} \;=\; VOM_i + HR_i \times p_t^{fuel} + e_i$$

where VOM_i is the variable operating and maintenance (O&M) costs, HR_i is the unit-specific heat-rate that captures the efficiency of a unit to convert fuel to electricity, p_t^{fuel} is the daily prices for unit i's fuel which is either coal or natural gas, and e_i is the environmental compliance costs.[20]

For co-generation, electricity that is not consumed on-site is sold to the wholesale market. We assume that output from these assets have a marginal cost equal to \$0/MWh. These units systematically bid a price of \$0/MWh. For a small number of hours, several natural-gas co-generation facilities bid positive offers into the wholesale market reflecting supply that can be produced using capacity that is not being utilized to meet on-site demand. For these units, we compute the marginal cost using the same methodology utilized for other natural gas resources. We abstract from computing the marginal costs of electricity from hydro resources because the firms of interest in our analysis have no hydro capacity.

6.3 Observed Expected Profit

In this section, we describe how we compute each firm's expected profits given the observed offer behaviour of all firms. It will be helpful to present an illustrative model. There are N firms competing in a series of uniform-priced procurement auctions indexed by time t. For each firm $i = 1, 2, ..., N$, we observe the hourly offer curves for non-wind generation units denoted by the non-

[20]See Appendix Section A for a detailed discussion on the data sources utilized to construct marginal cost.

decreasing supply functions $S_{it}(p)$ that specify an output level for each possible market-clearing price p. Define W_{it} to be firm i's wind output level in period t. Each firm has a total cost function $C_{it}(S_{it}(p))$ that represents the variable cost of generating $S_{it}(p)$ units of output.

In addition to the wholesale spot market, firms sign forward contracts that reflect the obligation to deliver a pre-specified level of output Q^f_{it} at a fixed price P^f_{it}. Forward quantities and prices are signed in advance of the spot market.[21] A firm is only paid the equilibrium spot market price (p^c_{it}) for their wholesale market output that has not been committed in advance via a forward contract (i.e., $S_{it}(p^c_t) + W_{it} - Q^f_{it}$). The payments from the forward contracted quantity equals $P^f_{it}\,Q^f_{it}$. Consequently, a firm i's observed profit level, given the market-clearing price p^c_t equals:

$$\pi_{it} = p^c_t[S_{it}(p^c_t) + W_{it} - Q^f_{it}] - C_{it}(S_{it}(p^c_t)) + P^f_{it}\,Q^f_{it}. \tag{2}$$

The market-clearing price p^c_t arises where market supply equals demand net of wind output:

$$\sum_{i=1}^{N} S_{it}(p^c_t) = ND_t(\eta_t) = D_t - W_t + \eta_t \tag{3}$$

where $ND_t(\eta_t)$ is stochastic net demand which depends on a deterministic level of price-inelastic market demand D_t, market-level wind output W_t, and a stochastic component η_t. Uncertainty in the net demand level ($ND_t(\eta_t)$) has an important impact on the resulting market-clearing price p^c_t.[22] The impact of uncertainty can be best illustrated by first defining the non-increasing residual demand function facing an individual firm i in period t to be the level of net demand minus the quantity supplied by all other firms:

$$RD_{it}(p, \eta_t) = ND_t(\eta_t) - \sum_{\substack{j=1 \\ j\neq i}}^{N} S_{jt}(p).$$

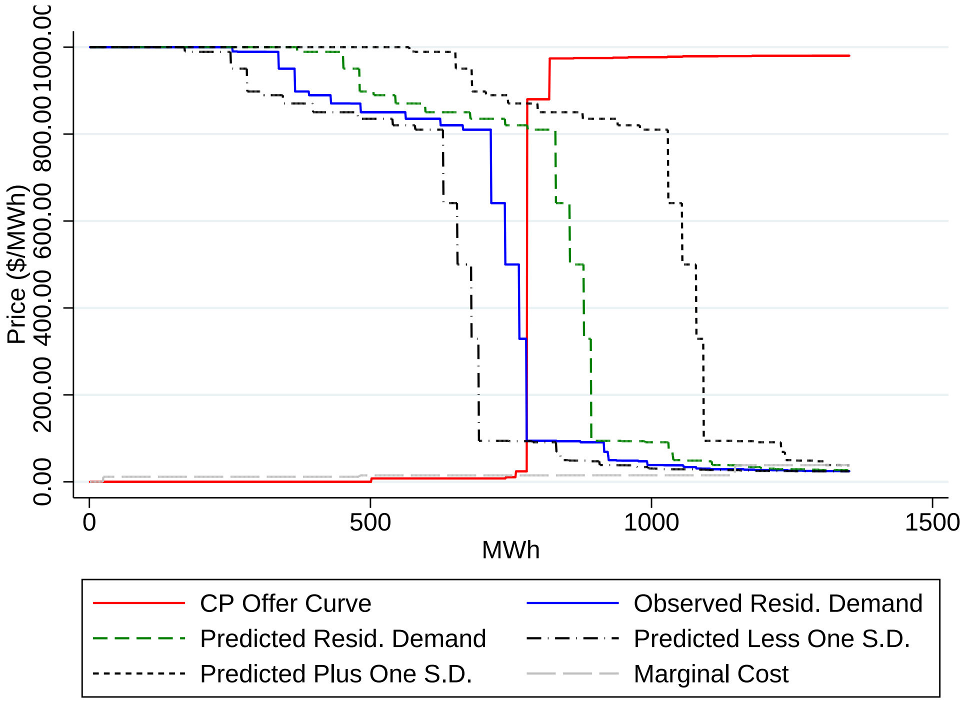
For any realization on η_t, from equation (3), the market-clearing price arises where firm i's supply function $S_{it}(p)$ intersects the residual demand function $RD_{it}(p, \eta_t t)$. Notice, because the stochastic component η_t enters the net demand function linearly, firm i's residual demand function will shift out towards the right as η_t increases.

Figure 7 presents an illustrative example of Capital Power's observed offer curve overlaid with several residual demand functions, including observed residual demand and the estimated residual demand function that reflects the estimated value of net demand via the regression model detailed in equation (1) above. Figure 7 also plots the residual demand functions with a one-standard deviation increase and decrease in the point-estimated value of net market demand (i.e., $\eta_t \in \{\sigma_{CP}, -\sigma_{CP}\}$ where $\sigma_{CP} = 200.11$ captures the uncertainty in the realization of net market de-

[21] For additional details on the role of forward markets, see Wolak (2007) and Brown and Eckert (2018).

[22] As discussed in detail in footnote 16, Capital Power has one wind facility which creates supply and demand-side uncertainty. For tractability purposes, we estimate the Net Demand function for Capital Power to be market demand net rival wind output and treat its own wind output as deterministic.

Figure 7: Illustration of Capital Power's Residual Demand Uncertainty, March 8, 2013 HE 19



mand). In the hour represented in Figure 7, the system marginal price (SMP) midway through the hour (corresponding to the observed residual demand curve shown) was \$329.00; throughout the hour the SMP ranged from \$49.00 to \$810.16, suggesting that our approach to demand uncertainty captures actual volatility in demand well. Overall, Figure 7 illustrates that the market-clearing price can vary considerably depending on the realization of the stochastic component in the net demand function. Consequently, it will be important to consider the presence of net market demand uncertainty when computing expected wholesale profits from the observed offer behaviour.

Two complications need to be considered before carrying out these calculations. First, we do not observe the forward contracted price level P_{it}^f. However, because both the forward contracted quantity (Q_{it}^f) and price level (P_{it}^f) are constants at the wholesale market stage and our focus is primarily on the change in expected spot market profits if Capital Power and TransCanada employed an alternative offer curve, the term $P_{it}^f Q_{it}^f$ will be canceled out in our main results.

Second, using (2), the level of forward contracted quantities will have an impact on a firm's wholesale profits because it impacts the amount of electricity output that is exposed to wholesale spot market prices. However, we do not have detailed data on TransCanada or Capital Power's forward market quantities. To establish estimates on the forward contracted quantities, we employ an approach utilized in Hortaçsu and Puller (2008) where Q_{it}^f is estimated as the quantity at which the observed offer curve intersects the marginal cost curve from below. This approach is driven by firms' incentives to bid below marginal cost for quantities where it is a net seller in the wholesale market (i.e., for quantities where its production is less than its forward contracted quantity).[23]

6.4 Offer Curve Counterfactuals

We construct an array of counterfactual offer curves for both Capital Power and TransCanada to investigate whether either firm could have elevated their expected profits by employing an alternative offer strategy. We undertake this approach because of the magnitude of the strategy space – each firm has multiple generation units that can offer up to seven price-quantity offers for each unit and hour. As a result, it is analytically intractable to characterize the Nash Equilibria.

As discussed in Section 5.2, we observe both Capital Power and TransCanada actively adjusting their offer behaviour on both tagging and non-tagging days. These offers often include pricing units above \$100/MWh in excess of their marginal cost for any hour in our sample period.

We run various counterfactuals that investigate whether firms were employing the optimal offer strategy on their high-priced units (i.e., on units price at or above \$100/MWh). For TransCanada, these offers systematically reflect a portion of its coal units (94%). For Capital Power, these offers are represented by its simple-cycle natural gas units (55%) or a portion of its coal units (45%). It is important to note that for both firms, a large portion of their remaining low-priced offers entail units being priced at \$0/MWh. These bids reflect a large portion of their coal units to ensure they are dispatched to satisfy their minimum stable generation constraints or co-generation units offering their electricity that results as a by-product of on-site industrial processes. These low-priced offers are stable in terms of price and magnitude (MWhs) throughout our sample.

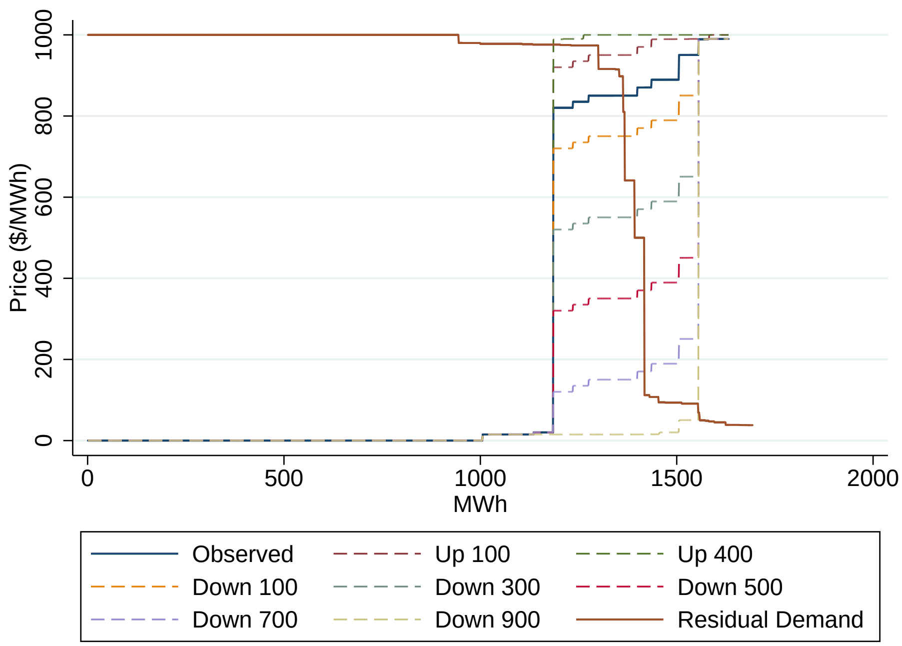
For both firms, we construct eighteen counterfactual offer curves that consider parallel shifts of \$100/MWh upwards and downwards on the observed offer behaviour of units that are priced between \$100/MWh and \$999/MWh.[24] These counterfactual offers are capped above by the price-cap of \$999.99/MWh and below by the units' short-run marginal cost. These counterfactuals capture the units and offer blocks whose bids are systematically adjusted throughout our sample period by both firms. Figure 8 illustrates an example of the various counterfactuals being considered for a given observed offer curve and realized level of residual demand for TransCanada.

In addition, for Capital Power, we often observe it pricing the entire capacity of its simple-cycle natural gas units at high prices above \$900/MWh. On tagging days, these units are often priced above \$900, tagged, and not called upon to supply. Consequently, for Capital Power, we employ thirteen additional counterfactual offer curves where these units are individually priced down to

[23] Brown and Eckert (2018) utilize an alternative structural estimation approach to estimate the implied level of forward contracted quantities in Alberta's electricity market. The authors find minimal differences in the estimated forward contract positions to those that arise using Hortaçsu and Puller's (2008) methodology. As an additional robustness check we recompute estimated forward positions increasing and decreasing short run marginal costs by 10%, and find that this results in changes to average estimated forward positions of 1 - 2%. Section 7.3.3 demonstrates that our results are robust to changes in forward contracted quantities.

[24] We do not consider units priced at or above \$999/MWh because based on discussions with industry experts these offers reflect assets that have been priced-out to ensure they are not called upon to supply electricity due to operation restrictions. For example, we often observe small portions of co-generation or coal units priced in this range. These offers are infrequent and small in magnitude.

Figure 8: Illustration of TransCanada's Counterfactuals, March 8, 2013 HE 22



their marginal cost (3), we price down (to marginal cost) the most efficient simple-cycle gas unit that is priced-out above \$900/MWh (1), and we adjust any of its simple-cycle gas units that are priced-out downward in increments of \$100/MWh (9). These counterfactuals cover hours where Capital Power is and is not employing its unique offer pattern because at least a portion of one of these natural gas units are being priced out a high prices in the majority of hours in our sample.[25]

7 Results

In this section, we provide the results of our counterfactual analyses. For each hour and firm, we compare the expected variable spot market profits that would arise from the observed offer strategies to those that would arise if the firm employed its optimal counterfactual unilateral deviation that resulted in the highest expected variable profits. Throughout our analysis, we will utilize the term supply cushion to reflect the amount of excess generation capacity that is available and not being utilized to meet expected market demand.[26] A high degree of market power has been documented at low to moderate supply cushion levels (Brown and Olmstead, 2017).

Table 2 presents summary statistics for several key market and firm-level variables, including firm-specific observed outputs and total costs. Computing observed firm-level profits is complicated

[25] Sweeting (2007) employed a strategy that elevated an individual generation unit's offers upward and downward by a fixed percentage. For analytical tractability, the majority of our counterfactuals move multiple units upwards and downwards by a fixed increment. For Capital Power, we adjust its individual simple-cycle gas units unilaterally. We find that these counterfactuals are not the most profitable deviation in the vast majority of hours.

[26] More specifically, the supply cushion variable reflects available dispatchable (non-renewable) generation capacity minus expected net market demand. This captures the amount of excess dispatchable generation capacity that is not being utilized to serve expected net demand.

by the fact that we do not observe forward prices (recall P_{it}^f equation (2)). However, for illustrative purposes, assume that forward price equals the spot price.[27] From Table 2, in this case the observed average hourly spot market profits for Capital Power and TransCanada are \$120,076 and \$178,034, respectively. These approximations will provide useful baselines in the subsequent results.

Table 2: Hourly Summary Statistics: Market and Firm-Level Variables

	Units	Mean	Std Dev	Min	Median	Max
Market Price	\$/MWh	123.28	226.91	10.03	35.23	999.99
Market Demand	MWh	8,547.63	556.61	7,145.36	8,525.03	10,309.77
Supply Cushion	MWh	1,817.40	552.73	153.00	1,865.27	3,740.00
Total Output - CP	MWh	1,103.14	174.02	565.67	1,140.82	1,554.99
Total Output - TC	MWh	1,604.95	295.48	872.00	1,568.00	2,446.00
Total Cost - CP	\$	15,913.94	3,305.74	7,809.29	15,849.69	26,219.66
Total Cost - TC	\$	19,816.49	5,142.46	7,542.80	19,197.66	81,766.52

7.1 Main Findings

We first consider whether Capital Power's expected spot profits would have increased by unilaterally adjusting its offer strategy, and whether such potential profit gains differ according to whether a day was "tagged" and by the level of the supply cushion. Figure 9 plots the histogram of hourly changes in expected profits from deviating to the optimal counterfactual by tagging and non-tagging days and supply cushion quartile. The "whiskers" above and below reflect the locations of the 90th and 10th percentiles, the center line corresponds to the median, and the diamond reflects the average. See Table A1 in the Appendix for a detailed summary of these results.

Figure 9 illustrates that on average, Capital Power's hourly expected variable profits would have increased considerably from deviating from its offer strategy, and that this increase is greatest on tagging days and hours in the 0 to 50th percentiles of the supply cushion. For example, the change in average hourly expected variable profits from deviating is 141% and 634% higher on tagged days than non-tagged days in the first and second quartiles of the supply cushion, respectively. The potential gains are considerable when compared to Capital Power's average hourly expected profit benchmark of \$120,076. For example, compared to this expected profit benchmark, Capital Power's average hourly expected profits increased 2.2% to 18.5% on tagged days. These profits dissipate as the supply cushion increases, but remains consistently higher on tagged days.

Figure 10 presents the distribution of changes in hourly expected profits from TransCanada's maximum profitable counterfactual and its observed offer strategy. The center line reflects the median, the diamond reflects the average, and the whiskers capture the 90th and 10th percentiles of the distribution. See Table A2 in the Appendix for a detailed summary of these results.

[27] In the literature, it is common to assume that the forward prices equal expected spot market prices resulting in the canceling out of the forward contracted terms in expected profits in equation (2) (e.g., Allaz and Vila (1993)).

Figure 9: Hourly Capital Power Profit Changes, by Tagging and Supply Cushion Quartiles

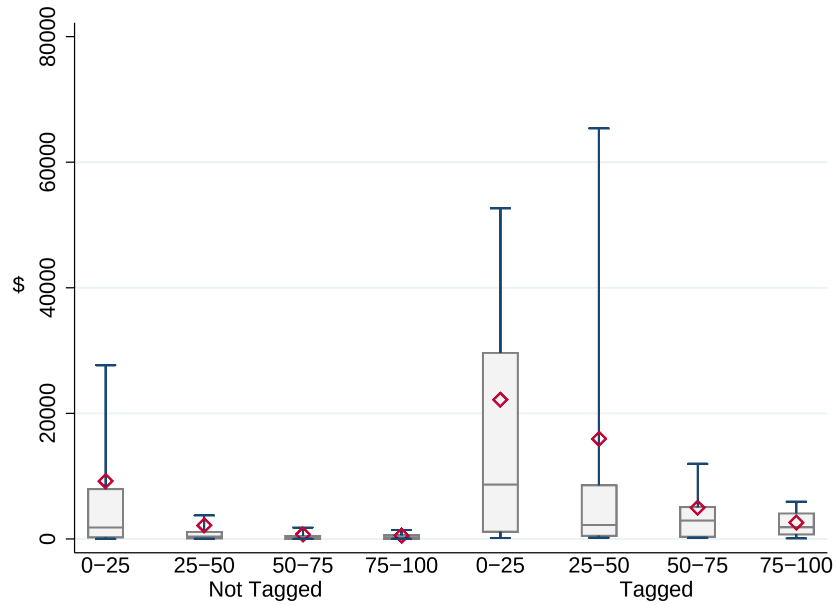
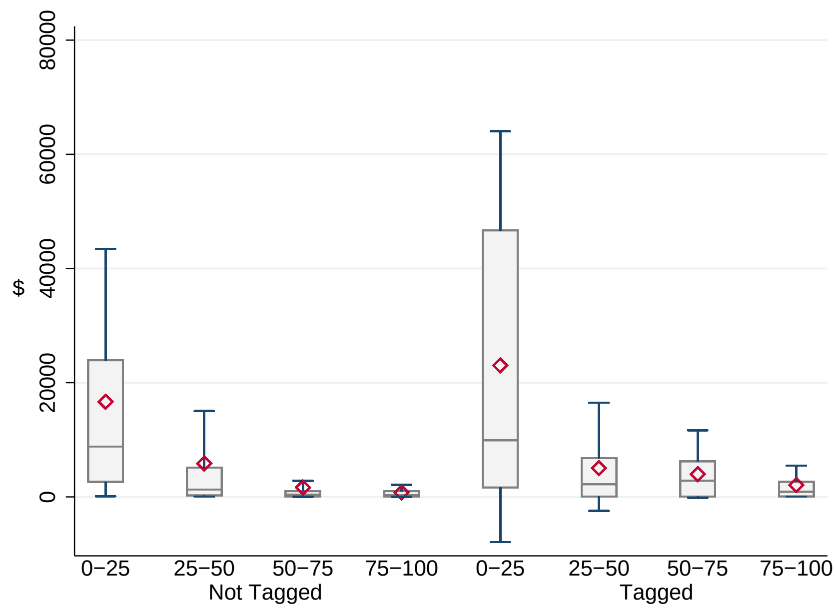


Figure 10: Hourly TransCanada Profit Changes, by Tagging and Supply Cushion Quartiles



As with Capital Power, Figure 10 illustrates that the mean change to TransCanada's expected profits from undertaking the optimal deviation is increasing as the market gets tighter (as the expected supply cushion falls). The expected change in profits from the optimal deviation is higher on tagged days in the first, third, and fourth quartiles of the supply cushion; however, we find that for hours with supply cushions in the second quartile, the profitability of deviating is slightly higher on non-tagged days. The potential increase to TransCanada's average hourly expected profits ranged from 1.2% to 13.1% on tagged days when compared to TransCanada's average hourly expected profit benchmark of \$178,034.

These results suggest that both TransCanada and Capital Power were foregoing profitable deviations that would elevate expected variable profits. Further, these profitable deviations are highest in the tightest supply cushion hours and on days where Capital Power is employing its tagging pattern. We formally test whether the means of the hourly profitable deviations are statistically different from zero, and if this effect varies statistically by tagged day and supply cushion. To do so, for each firm $i \in \{TC, CP\}$, we estimate a model of the form:

$$\Delta\,\pi_{it} \;=\; \beta_{0i}+\beta_{1i}\,\text{Tag Day}_t+\beta_{2i}\,\text{Supp CushionQ1}_t+\beta_{3i}\,\text{Supp CushionQ2}_t+\beta_{4i}\,\text{Supp CushionQ3}_t+\epsilon_{it} \tag{4}$$

where $\Delta\,\pi_{it} = \pi_{it}^{MaxCF} - \pi_{it}^{Obs}$ is the difference between the expected variable profits of the maximum profitable counterfactual unilateral deviation and the observed outcome, Tag Day_t equals 1 if Capital Power utilized its tagging pattern in at least one hour of the relevant day and zero otherwise, and Supp CushionQj_t equals 1 if the supply cushion falls in quartile Qj for $j = 1, 2, 3$ and zero otherwise.[28,29] To ensure that our results are not being driven by outliers, we exclude outliers at the top and bottom 1% of the $\pi_{it}^{MaxCF} - \pi_{it}^{Obs}$ distribution.[30] The error term η_t is robust to heteroskedasticity and auto-correlation to account for within-day serial correlation. Because of the endogeneity of tagged day, it is important to note that we aim to solely test if the values of $\Delta\pi_{it}$ are statistically different from zero and if this significance differs by tag day and supply cushion.

In addition to the baseline model in (4), we also run a model with a collection of calendar variables including dummies for each hour and month, and a covariate for weekday and holidays. This allows us to investigate if the statistical significance of the tag day and supply cushion variables are robust to the inclusion of variables that control for systematic demand variation that could be driving the differences in expected profits on tagged versus non-tagged days or by supply cushion.

Table 3 presents the results of this statistical analysis.[31] We first discuss the results for Capital Power. The constant in column (1) indicates that there is no statistically significant increase

[28] We categorize the supply cushion in this manner to parallel the approach in Figures 9 and 10. However, we also utilized a continuous measure of the supply cushion and our results are robust.

[29] We focus on tagging days rather than tagging hours because as discussed in Section 5.1 we observe Capital Power employing the unique tagging behaviour in the early morning hours and often holding the tag through the majority of the day. As shown in Figures 2 and 3, on days where it employs the tagging pattern, Capital Power creates a large offer-shelf that systematically remains at high prices into the evening hours. In some instances, on these days Capital Power stops employing the tagging pattern late in the evening but the shelf remains. We also rerun our regressions with tagging hours and the qualitative results remain.

[30] Inclusion of these hours reduces the precision of the model and affects the normality assumption of error term. However, the statistical significance and qualitative conclusions presented below are robust.

[31] We have 4,004 hours in our sample. In addition to dropping outliers in the top and bottom 1%, for both firms our analysis drops hours in which the firm has no price offerings at or above \$100/MWh. This arises more often for TransCanada. In these hours, our counterfactuals which focus on high-priced offers are not relevant. It is important to note that in these hours, either firm bids all of their available capacity at low-priced offers (often at \$0/MWh). Further, these hours are systematically in the highest quartile of the supply cushion where observed prices are in the bottom 25th percentile. We do not consider additional counterfactuals on these low-priced offers because our focus is on strategic behaviour on the firms' high-priced offers far in excess of marginal cost.

Table 3: Statistical Test for Best-Response Bidding Behaviour by Tag Day and Supply Cushion

Variable	Capital Power		TransCanada	
	(1)	(2)	(1)	(2)
Tag Day	5,796.70***	4,436.69**	1,811.96	3,299.21*
	(1,517.25)	(1,844.31)	(1,322.99)	(1,808.09)
Supp Cushion Q1	7,962.73***	8,664.64***	15,006.37***	15,711.35***
	(1,038.22)	(1,097.36)	(1,404.32)	(1,607.86)
Supp Cushion Q2	2,000.15***	2,294.30***	4,186.33***	4,961.30***
	(549.05)	(638.86)	(739.04)	(970.44)
Supp Cushion Q3	483.58**	503.28**	1,007.83***	1,264.09**
	(210.65)	(254.88)	(350.43)	(520.43)
Constant	128.22	-638.50	683.92***	764.24
	(192.73)	(886.95)	(247.11)	(1,353.97)
Observations	3,790	3,790	2,320	2,320
Calendar Controls	No	Yes	No	Yes
F-Stat	18.31***	4.60***	32.69***	7.02***
R^2	0.1666	0.2104	0.2284	0.2602

Notes. Regressions in columns (2) for each firm include time controls for each hour, month, day of week, and holiday. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

in profits from devating on non-tagged days in the fourth quartile of the supply cushion. The coefficients on tagging day and the supply cushion variables demonstrate that the effect of deviating on expected profits is positive and significant on tagging days, and that this effect increases as we move into the tightest supply cushion hours. All of these effects are statistically significant. Column (2) demonstrates that the magnified effects on tagging days and in the tightest supply cushion hours are positive and statistically significant even after including the calendar controls.

For TransCanada, focusing on column (1), the constant demonstrates that there is a positive and statistically significant difference between the expected profits of the maximum profitable deviation and the observed offer behaviour in the fourth quartile of the supply cushion. The positive and statistical significance of the supply cushion variables indicate that this effect is magnified as we move to the tightest supply cushion hours. In contrast to Capital Power, we do not find that there is statistically significant evidence that this effect increases on tagging days. In column (2), after controlling for the calendar covariates, we continue to find a magnified positive and statistically significant effect in the tightest supply cushion hours. Further, we find that there is positive and marginally statistically significant evidence that the change in TransCanada's expected profits was higher on days where Capital Power employed its unique tagging pattern.

To better understand the magnitude and statistical significance of these results, Table 4 presents the marginal effects of our baseline regression models (presented in columns (1)) by supply cushion and tagging day. For each supply cushion quartile and tagging day category, we carry out Wald tests for joint significance. Under the null hypotheses, the expected optimal counterfactual and

Table 4: Marginal Effects of the Optimal Deviation by Tag Day and Supply Cushion

	Capital Power		TransCanada	
	Non-Tagged	Tagged	Non-Tagged	Tagged
Supp Cushion Q1	8,090.95***	13,887.65***	15,690.29***	17,502.25***
	(61.57)	(62.73)	(126.11)	(90.04)
Supp Cushion Q2	2,128.37***	7,925.07***	4,870.25***	6,682.21***
	(20.46)	(21.95)	(42.25)	(24.63)
Supp Cushion Q3	611.81***	6,408.51***	1,691.76***	3,503.72***
	(12.06)	(19.15)	(22.87)	(7.87)
Supp Cushion Q4	128.22	5,924.92***	683.92***	2,495.88**
	(0.44)	(18.40)	(7.66)	(4.67)

Notes. Marginal effects of the baseline models. F statistics of the Wald Test are presented in parentheses. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

observed profits have the same means. For both firms, Table 4 demonstrates that each firm could have elevated their average hourly expected profits. This effect is magnified in the tightest supply cushion hours and on tagging days. These effects are statistically significant at the one-percent level of significance for all categories except in the fourth quartile of the supply cushion.

Taken together, these results provide evidence that both Capital Power and TransCanada do not employ the expected static profit-maximization offer strategies. For both firms, the profitable unilateral deviations are magnified in the tightest supply cushion hours. These effects are all statistically significant. For Capital Power, there is statistically significant evidence that the profitable unilateral deviations are magnified on tagged days across all supply cushion quartiles.[32]

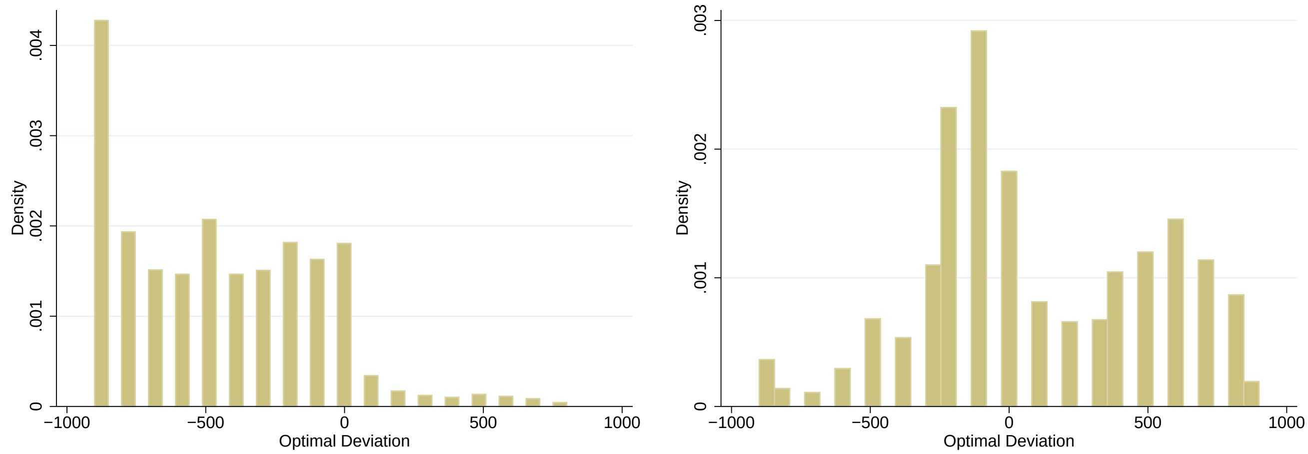
7.2 Complexity of Optimal Deviations

In our analysis above, for each hour we selected the optimal counterfactual that maximized each firm's expected variable profits among a wide array of counterfactuals. In this section, we investigate the complexity of the unilateral deviations that would need to be employed in order for a firm to achieve the optimal counterfactuals. Further, we estimate the expected increase in variable profits if a firm employed a simplified rule-of-thumb unilateral deviation strategy.

Figure 11 presents the distribution of the optimal unilateral deviations for both firms.[33] Values of zero reflect hours where the observed offer behaviour results in higher expected variable profits than any of the potential counterfactuals. Figure 11a illustrates that Capital Power could have employed a relatively simple unilateral deviation strategy that priced down its high-priced units. The most commonly profitable unilateral deviation strategy would have entailed Capital Power

[32] We also investigated if there is a change in our analysis after August 7, 2013 when the MSA's (2013a) report on the HTR was released. Shortly after, TransCanada stopped utilizing its tagging patter and Capital Power's tagging pattern was observed throughout September (and three hours in December). We find no statistically significant evidence that the coefficients estimated in (4) differed before or after the MSA's report was published.

[33] For certain hours, a firm's expected profits would have been the same across multiple counterfactuals. In this setting, we selected the counterfactual that entailed an offer strategy that is closest to the observed offer strategy (i.e., reflecting the smallest change in offer behaviour to achieve the optimal counterfactual variable profits).



(a) Capital Power

(b) TransCanada

Figure 11: Distribution of Optimal Unilateral Deviations by Firm

pricing down its high-priced units by \$900 towards their marginal cost of production.[34] However, for the majority of hours, Capital Power could have employed numerous smaller unilateral deviations downward and achieved a similar level of increased expected variable profit.

Figure 11b illustrates that TransCanada's optimal deviation strategy is substantially more complex and widely distributed across the full range of potential price deviations. In addition, for certain days, the optimal deviation path would entail TransCanada unilaterally adjusting its offers down \$500 or more in one hour and up \$500 or more from its original offer strategy the next. This suggests that TransCanada would have had to employ a sophisticated optimal deviation strategy to achieve the high level of unilateral deviation profits demonstrated above.

To investigate whether either firm could have employed a simple unilateral deviation strategy and elevated their expected variable profits, we consider rule-of-thumb deviations that entail the firm employing one of our counterfactuals for all hours. While this will represent a lower bound on the potential profitable deviations as firms could better tailor their deviations to the strategic environment, it provides insight into whether or not the firms could have still elevated their expected profits without requiring a sophisticated and potentially volatile optimal deviation path.

Table 5 presents the results of regression model detailed above in (4) for the simple rule-of-thumb unilateral deviation strategy that results in the highest average expected change in variable profits.[35] For Capital Power, this deviation involves it unilaterally decreasing all high-priced assets by \$200/MWh, whereas for TransCanada the high-priced blocks are reduced by \$100/MWh. For Capital Power, the constant term in column (1) demonstrates that its expected variable profits

[34] As noted below, this is not the "best" simple rule-of-thumb strategy that Capital Power could have employed to increase its average expected profits by the highest amount across all hours because it often results in large positive and negative levels of expected variable profits.

[35] More specifically, we considered all possible combinations of rule-of-thumb unilateral deviation strategies. Table 5 presents the results for the strategies that result in the highest average change in expected profits for both firms. The other simple rule-of-thumb strategies either resulted in smaller positive or negative coefficient estimates.

Table 5: Statistical Test for Simple Unilateral Deviation by Tag Day and Supply Cushion

Variable	Capital Power (Down $200)		TransCanada (Down $100)	
	(1)	(2)	(1)	(2)
Tag Day	3,953.40***	2,738.61**	650.81	476.76
	(1,244.95)	(1,430.65)	(1,020.91)	(1,256.40)
Supp Cushion Q1	5,914.31***	6,651.20***	1,783.41**	2,690.02**
	(893.27)	(1,002.57)	(906.21)	(1,027.91)
Supp Cushion Q2	1,415.19***	1,816.73***	-353.70	107.89
	(405.26)	(504.28)	(304.89)	(517.44)
Supp Cushion Q3	385.28***	457.10**	5.06	298.17
	(123.89)	(195.22)	(188.80)	(287.01)
Constant	-313.38**	-50.49	102.13	-20.80
	(153.51)	(992.60)	(166.94)	(786.67)
Observations	3,790	3,790	2,320	2,320
Calendar Controls	No	Yes	No	Yes
F-Stat	13.75***	2.96***	1.70	2.36***
R^2	0.1354	0.1697	0.0184	0.0613

Notes. Capital Power and TransCanada results reflect a unilateral deviation downward of $200 and $100 on its high-priced units in each hour, respectively. Regressions in columns (2) for each firm include time controls for each hour, month, day of week, and holiday. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

would have declined in the fourth quartile of the supply cushion. However, on tagging days and the first, second, and third quartiles of the supply cushion, the change in Capital Power's hourly expected variable profits would have increased by employing the simple unilateral deviation strategy. These effects are all statistically significant.

Column (2) illustrates that the impact of supply cushion and tagging day variables are robust to the inclusion of the calendar covariates. Alternatively, there is limited statistically significant evidence that TransCanada could have employed a simple rule-of-thumb unilateral deviation strategy and elevated its expected variable profits on average, with the exception of the lowest quartile of the supply cushion. Table A4 presents the marginal effects of the simple rule-of-thumb regressions (in columns (1)) by supply cushion and tagging day categories. These results further illustrate the fact that Capital Power (TransCanada) could (could not) have employed a relatively simple rule-of-thumb strategy and elevated its expected profits.

7.3 Extensions

In this subsection, we employ numerous extensions to rule out alternative explanations for our findings and demonstrate their robustness. In particular, we investigate dynamic costs, variations in forward positions, consider the presence of a price-responsive load in the wholesale market, and investigate if ATCO was behaving in a manner consistent with unilateral profit-maximization.

7.3.1 Dynamic Costs

Our analysis has focused on static marginal costs of operating a generation unit. However, there may be concerns that the expected gains from unilaterally deviating are biased upwards because our analysis abstracts from start-up costs and costs of cycling an asset's output upwards or downwards. For example, if a firm's optimal unilateral deviation entails it starting up a new generation unit that was previously not providing any electricity, they must incur a start-up cost that can range from \$12 to \$286 per MW of capacity (Kumar et al., 2012).

It is important that we consider the impact of these costs on our baseline results. To do so, we analyze the change in each firm's expected dispatch probability and output of its generation assets under the observed and optimal counterfactual offer curves. For example, if under the observed offer curve, a firm's peaker gas unit has a zero probability of being called upon to supply output, but a high probability under the optimal counterfactual offer curve, we elevate the expected cost the firm will incur in the counterfactual by the expected start-up cost of the peaker gas unit.

For TransCanada, this asset-level analysis illustrates that under the optimal counterfactual it is adjusting the expected output of its coal units (either upward or downward) in 84% of the observed changes in expected output. For the remaining cases, TransCanada is adjusting its expected output from its co-generation facilities. In both cases, these units are always producing positive output by submitting a portion of their units' capacity at a price of zero to ensure that the assets are producing at or above their minimum stable generation values. Consequently, TransCanada's counterfactuals do not entail units turning on or off.

While additional start-up costs are not being incurred, there are additional costs incurred by cycling these units' output upward or downward. We utilize estimates on generation unit cycling costs to compute the expected cycling costs under the observed and optimal counterfactual offer strategies.[36] While cycling costs increase under the optimal counterfactual, the additional expected costs are small and only reduce the change in the difference between expected profits from employing the optimal counterfactual and observed offer curve (i.e., $\Delta\pi_{TC,t}$) by \$25.80 an hour on average (with a median of \$1.01). We find that theses cycling costs do not change the statistically significant differences demonstrated above.

For Capital Power, the asset-level analysis illustrates that it is adjusting the expected output (often upward) on its peaker gas units in the optimal counterfactual offer curve in 57% of the observed changes in expected output. In all other cases, Capital Power is adjusting the expected output of its coal units (often upwards) which are operating a portion of their assets capacity at a price of zero to ensure it is called upon to supply at or above its minimum stable generation level in both the observed and optimal counterfactuals. In the former case, its counterfactuals can entail starting-up its natural gas units. In the latter case, these units do not incur start-up costs.

[36] More specifically, we use the 75th percentile of the estimated cycling (load following) costs of large coal and natural gas assets in Kumar et al. (2012), adjusted from US to Canadian Dollars using the 2011 Bank of Canada exchange rates. These estimates are then inflation-adjusted to transfer these estimates into 2013 CAD \$ values.

We first focus on estimating additional generation unit cycling costs that may be incurred by Capital Power adjusting its expected output upward or downward under the optimal counterfactual. Similar to TransCanada, we find that the change in its expected cycling costs reduce the change in the difference between expected profits from employing the optimal counterfactual and observed offer curve ($\Delta\pi_{CP,t}$) by \$30.04 an hour on average (with a median of \$5.01). We find that this has no impact on the qualitative or statistically significant results demonstrated above.

In the hours where the optimal counterfactual entails changing the expected output of Capital Power's peaker gas units (e.g., by raising its dispatch probability above zero), it may incur additional start-up costs. AESO (2019) estimates these start-up costs of peaker gas units to be \$2,146 per start-up. For each hour, we estimate the expected probability that the gas assets will be dispatched and multiply it by the associated start-up costs to establish an expected start-up cost measure under the observed and optimal counterfactual offer curves. We then estimate the additional expected start-up costs that were incurred under the optimal counterfactual and adjust our expected profit difference measure $\Delta\pi_{CP,t}$. We take the overly conservative assumption that these start-up costs are incurred in every hour. This abstracts from dynamic considerations where the peaker gas unit incurs the start-up costs in the first hour and operates for several hours.[37] Because the optimal counterfactuals systematically entail pricing-down a portion of its peaker gas units, this will bias the expected change in variable profits downward.

Table 6: Statistical Test for Best-Response Bidding Behaviour - Capital Power Dynamic Costs

Variable	Capital Power	
	(1)	(2)
Tag Day	5,499.78***	3,586.63**
	(1,475.70)	(1,776.89)
Supp Cushion Q1	6,984.33***	7,775.81***
	(983.94)	(1053.66)
Supp Cushion Q2	1,295.57**	1,742.76***
	(546.11)	(627.00)
Supp Cushion Q3	17.11	144.92
	(206.07)	(251.56)
Constant	-205.92	-1,272.24
	(188.01)	(891.70)
Observations	3,790	3,790
Calendar Controls	No	Yes
F-Stat	16.42***	4.16***
R^2	0.1517	0.1901

Notes. Regressions in columns (2) for each firm include time controls for each hour, month, day of week, and holiday. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

[37] AESO (2019) notes that peaker gas units in Alberta operate for approximately 4.5 hours on average.

Table 6 presents the results of Capital Power's statistical analysis with $\Delta\pi_{CP,t}$ adjusted to account for the increased expected start-up and cycling costs. Comparing the results to Table 3, we find that the key qualitative findings persist.[38] As expected, Table A5 in the Appendix illustrates that the inclusion of the dynamic costs reduces the expected hourly profits in all supply cushion regions. However, Table 6 illustrates that we continue to find statistically significant and positive differences on tagged days and the first two quartiles of the supply cushion.

7.3.2 Price-Responsive Load

In our baseline analysis, we assumed that wholesale demand is perfectly price-inelastic. However, in Alberta there is a small set of industrial consumers in the pulp, paper, forestry, and petrochemical sectors that are exposed to hourly wholesale prices. These consumers have been observed to be responsive to hourly wholesale prices (Brown and Olmstead, 2017). We have hourly aggregate demand data for these industrial consumers which can represents up to 8% of hourly demand. Similar to Brown and Olmstead's (2017) analysis, for each hour t we estimate the quantity demanded for these industrial consumers as a linear-log function of wholesale price p_t:

$$Q_t^{Industrial} = \alpha_0 + \alpha_1 ln(p_t) + \alpha_2 ln(p_t^{NG}) + \theta h(\text{Temp}_{AB,t}) + \vec{\gamma}\mathbf{X}_t + \eta_t$$

where p_t is the price of electricity, p_t^{NG} is the price of natural gas to control for fuel-substitution via behind-the-meter co-generation, $h(\text{Temp}_{AB,t})$ is a non-linear function of temperature variables, and $\mathbf{X}_t$ is a vector of calendar controls including hour, weekday, and month dummies to control for systematic non-price related demand variation.[39] The error term η_t is robust to heteroskedasticity and serial correlation via Newey-West standard errors to account for within-day serial correlation.

Estimating the relationship between electricity demand and market price is complicated by the fact that price impacts demand and industrial demand can impact of wholesale prices. This creates potentially correlation between the price variable and the error term. To account for this endogeneity, we estimate the regression above using two-stage least squares by finding instrumental variables (IVs) for wholesale prices. We use supply shifters as IVs that impact demand only through their impact on the electricity price. The exclusive instruments are observed hourly wind production and generation capacity supply availability that reflects the sum of available generation capacity within Alberta and transmission import inter-tie capacity limits.

Table A6 provides detailed estimates of the first and second-stages of the IV regression. The coefficients imply average price-elasticities of -0.226. We adjust the residual demand functions detailed above to account for the presence of this price-responsive load and re-run our analysis.

Table 7 presents the results of our statistical analysis. The qualitative conclusions of our

[38] The one exception is that looking at column (1), there is no longer any statistically significant evidence that Capital Power's expected variable profit is different from zero in the third quartile of the supply cushion.

[39] The temperature variables are modeled as hourly cooling degrees (hourly mean degrees above 18.33° Celsius) and heating degrees (hourly mean degrees below 18.33° Celsius) in Calgary and Edmonton. This data is accessed through Environment Canada: Weather Information. We include the level and quadratics of these variables.

Table 7: Statistical Test for Best-Response Bidding Behaviour - Price-Responsive Load Robustness

Variable	Capital Power		TransCanada	
	(1)	(2)	(1)	(2)
Tag Day	5,504.43***	3,988.58**	2,256.06	3,296.01*
	(1,444.41)	(1,630.46)	(1,452.08)	(1,934.81)
Supp Cushion Q1	7,448.82***	8,079.45***	12,168.59***	13,291.32***
	(904.03)	(931.08)	(1,261.97)	(1,433.29)
Supp Cushion Q2	1,791.25***	2,093.82***	2895.31***	4,007.11***
	(506.05)	(580.49)	(778.55)	(1,008.66)
Supp Cushion Q3	371.12**	429.14**	587.91**	1,092.52***
	(167.31)	(213.54)	(266.39)	(387.75)
Constant	101.69	-71.30	609.05**	238.36
	(182.54)	(832.77)	(263.87)	(1,175.28)
Observations	3,790	3,790	2,320	2,320
Calendar Controls	No	Yes	No	Yes
F-Stat	19.85***	4.43***	25.43***	6.04***
R^2	0.1767	0.2103	0.2059	0.2360

Notes. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

analysis are robust. For Capital Power, we find statistically significant differences between the expected profits from employing the optimal counterfactual and observed offer behaviour on tagging days and hours in the first through third-quartiles of the supply cushion. For TransCanada, we find that there is marginally statistically significant evidence that the difference in expected profit was larger on tagged days when calendar controls are included. We continue to find large positive and statistically significant effects for TransCanada across the first three supply cushion quartiles. For both firms, the coefficients are largest for tagging days and hours in the tightest supply cushion.

Table A7 in the Appendix presents details results of the statistical analysis that tests if there are differences between the expected variable profits from using the best simple rule-of-thumb strategy that employs a single unilateral deviation across all hours compared to observed behaviour. Similar to the results in Section 7.2, we find that Capital Power could have employed a simple deviation strategy and achieved the statistically significant increase in its expected profits in all hours except those in the fourth quartile of the supply cushion on non-tagging days. For TransCanada, we continue to find evidence that it could have only achieved statistically significant increases by employing a simple deviation strategy in hours in the first quartile of the supply cushion.

7.3.3 Forward Positions

We employed Hortaçsu and Puller's (2008) approach to estimate the firms' forward contract positions. Analogous to previous literature, we find that both firms have a high level of forward contract coverage as a percentage of hourly output. Capital Power and TransCanada's estimated forward contract coverage as a percentage of output is in excess of 90% and 80% for the majority of hours, respectively.[40] Brown and Eckert (2018) use a structural approach to calibrate firms' forward positions in Alberta in 2013 - 2014 and find a similar forward contract coverage.

However, one might be concerned that our forward contract estimates can change the conclusions of our analysis. We rerun our analysis assuming that Capital Power had a forward contract coverage of 80%, 85%, and 90% reflecting a 7.2% to 21.25% reduction from our estimated average forward contract coverage. For TransCanada, we consider the range 70%, 75%, and 80% reflecting a 9.1% to 20.5% reduction from our estimated average forward contract coverage. It is important to note that as a firms' forward coverage decreases, they have stronger incentives to reduce their output in equilibrium (e.g., by bidding less aggressively) (Bushnell et al., 2008).

Table 8: Statistical Test for Best-Response Bidding Behaviour - Forward Position Robustness

Variable	Capital Power			TransCanada		
	90%	85%	80%	80%	75%	70%
Tag Day	4,888.08***	4,469.08***	3,811.48***	2,153.68	2,250.37	3,217.30
	(1,417.34)	(1,351.52)	(1,252.39)	(1,650.22)	(1,685.74)	(1,949.93)
Supp Cushion Q1	6,770.27***	6,622.07***	6,690.54***	14,291.03***	16,262.09***	16,852.50***
	(865.33)	(861.63)	(871.66)	(1,427.53)	(1,543.81)	(1,589.19)
Supp Cushion Q2	1,423.20***	1,537.38***	1,593.49***	5,068.17***	5,845.46***	6,909.82***
	(475.21)	(467.36)	(430.72)	(886.22)	(999.22)	(1,189.65)
Supp Cushion Q3	353.15*	307.94*	293.93*	911.49**	1,004.62**	1,153.37**
	(194.66)	(182.70)	(169.34)	(409.17)	(503.87)	(598.40)
Constant	1.43	-55.29	-54.90	879.24**	1,175.94***	1,355.27**
	(177.08)	(169.54)	(157.17)	(382.97)	(450.84)	(540.79)
Observations	3,790	3,790	3,790	2,320	2,320	2,320
F-Stat	16.80***	16.82***	17.19***	27.82***	32.08***	32.98***
R^2	0.1622	0.1545	0.1549	0.2063	0.2143	0.2028

Notes. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 8 presents the results from our statistical test. For Capital Power, the key conclusions persist. We continue to find positive and statistically significant differences on tagged days and hours in the first to third quartiles of the supply cushion. The only difference from our baseline analysis is that the coefficient on the third supply cushion is only marginally significant.

For TransCanada, Table 8 demonstrates that we continue to find statistically significant evidence that it could have employed the optimal deviation strategy to elevate its expected profits. Unlike Capital Power, we find that the magnitude of the coefficients increase consistently as TransCanada's forward position decreases. This arises because TransCanada's optimal deviation in the baseline analysis is a mix of deviations upwards and downwards. As the forward contracts decline, its optimal deviation becomes systematically to unilaterally adjust its high-priced units upward. The gains from doing so are magnified when its forward contracts decrease.

Table A8 in the Appendix investigates if either firm could have employed a simple rule-of-thumb deviation strategy to increase its expected profits. Analogous to the results in Section 7.2, we find

[40]Several studies either have forward contract data or use observed behaviour to estimate forward positions and find estimates between 85% and 103% (e.g., Hortaçsu and Puller (2008), Wolak (2007), Reguant (2014)).

statistically significant evidence that Capital Power could have elevated its expected profits by employing a simple deviation strategy (i.e., by bidding more aggressively) on tagged days and in the tightest supply cushion hours.

For TransCanada, for small changes in the forward position, we continue to find that its optimal deviation strategy remains quite dispersed over the potential counterfactuals in our analysis and we find no statistically significant evidence that it could have employed a simple deviation strategy and increased its expected profits. However, as we reduce its forward position further, TransCanada's optimal counterfactual strategy begins to entail it consistently deviating upwards. For a sufficiently low forward contract position, Table A8 illustrates that we begin to find statistically significant evidence that it could have elevated its expected profits by employing a simple pricing out deviation strategy in certain regions of the supply cushion. However, these results also demonstrate that this may be a risky strategy as TransCanada could incur statistically significant reductions in its expected profits by employing the simple deviation strategy (e.g., on tagging days).

7.3.4 ATCO Offer Behaviour

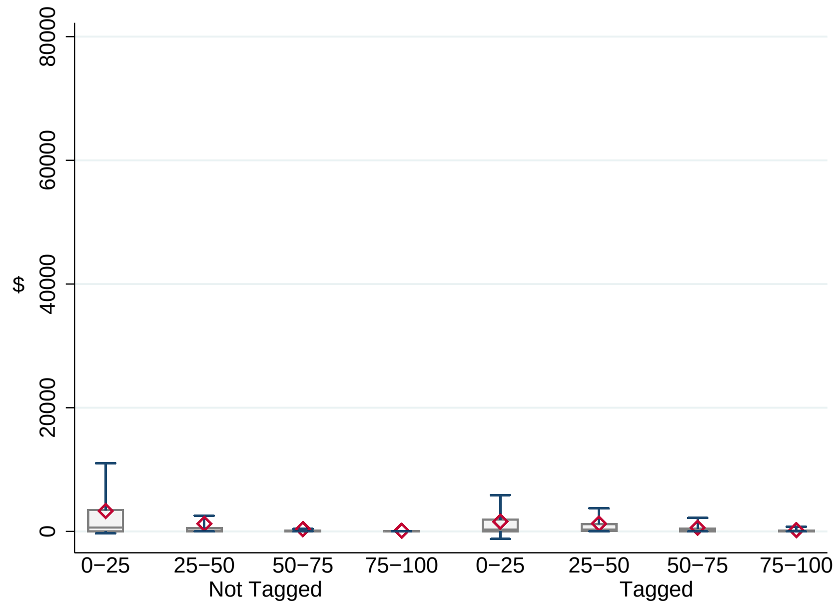
For reasons documented earlier, our analysis focused primarily on Capital Power and Transcanada. However, as illustrated in Figure 4, ATCO also adjusted its behaviour on tagged days. Further, ATCO was one of the firms discussed in the examples presented in MSA (2013a). Therefore, in this section, we present results from an analysis considering an array of eighteen counterfactuals for ATCO that consider parallel shifts of \$100/MWh upwards and downwards on the observed offer behaviour for its high-priced units above \$100/MWh. These units consist of simple-cycle (peaker) natural gas assets. It is important to note that ATCO's remaining units are primarily cogeneration facilities that are systematically priced-in at low prices, often \$0/MWh.

Figure 12 presents a box and whisker plot of the hourly expected changes in variable profits from undertaking the optimal deviation, where the box reflects the inner quartile range, the whiskers capture the 90th and 10th percentiles of the distribution, and the diamond captures the average. For comparison the vertical axis scale matches those in Figures 9 and 10. Figure 12 demonstrates that unlike the other two large firms, we find limited evidence that ATCO could have adjusted its offer behaviour unilaterally and elevated its expected profits. Our statistical analysis of ATCO finds limited evidence that the change in expected profits is statistically different from zero across all supply cushion levels or by tagging day status. This evidence suggests that ATCO's offer behaviour was consistent with unilateral expected profit maximization.

8 Conclusions

A difficulty in cases involving an allegation of coordinated behaviour is that suspicious conduct observed by firms suspected of coordination may have other explanations. As a result, it is important that in such cases an analysis be carried out to investigate whether observed conduct is consistent with unilateral profit maximization, or is better explained by a theory of coordinated

Figure 12: Hourly ATCO Profit Changes, by Tagging and Supply Cushion Quartiles



behaviour. In this paper, we carry out such an exercise in the context of Alberta's wholesale electricity market, in which the industry's monitoring agency had accused certain firms of setting prices designed to convey information to rivals and to signal intentions regarding future behaviour.

Our empirical approach takes into account the volatility of hourly demand and wind supply, and considers whether, given the offers of rivals, a firm could improve expected profits unilaterally through an array of possible deviations from its observed offers. We focus primarily on two firms (Capital Power and TransCanada) that were the subject of concerns raised by the Alberta Market Surveillance Administrator. We demonstrate that when Capital Power employs its unique offer pattern, it systematically prices out several of its large generation units establishing a high-priced shelf. Subsequently, TransCanada often adjusted its offers upwards.

Our empirical analysis finds that both of these firms could have unilaterally increased their expected profits through undertaking unilateral deviations. In particular, for Capital Power, our analysis finds that the potential gains in its expected profits are pronounced on days where it employed its unique offer pattern resulting in increases of up to 18.5% in its hourly expected profits. We demonstrate that Capital Power could have achieved a sizable portion of these expected profit gains by undertaking a simple rule-of-thumb unilateral deviation strategy that involved it adjusted its high-priced offers downward. We demonstrate that these results are robust to dynamic start-up costs that may explain the pricing out of its natural gas units.

For TransCanada the results are less clear; while deviating optimally could unilaterally increase its expected profits, such deviations are complicated and involve both increasing and decreasing offers depending on circumstances. Further, there is limited evidence that the profitability of deviating is greater on days in which pricing patterns are employed. In addition, we also investigate the offer behaviour of a third large firm (ATCO) that adjusted its offer behaviour in our sample, but did not employ a clear unique offer pattern. We illustrate that this large firm is behaving in a manner that is consistent with unilateral expected profit maximization.

Our results are therefore consistent with a firm taking a leadership role to increase market prices in certain hours. Further, our results provide support for the concerns raised by the MSA that unique pricing patterns may have played a role in coordinating on high-priced outcomes.

In the face of increased renewable generation resources, there is a recent movement to increase market information and transparency to better manage renewable resource intermittency and facilitate more accurate price forecasts for market participants (e.g., see EU (2013)). However, our findings provide support for concerns that such information can be detrimental to market competition in concentrated wholesale electricity markets where firms interact repeatedly.[41] In addition, attempts to de-identified data published in near real-time may not be sufficient to alleviate concerns over the use of market information to facilitate coordinated behaviour.

Our analysis suggests several directions for future research. Our analysis of dynamic costs computed ramping and startup costs associated with the deviations that were optimal if these costs were ignored. A more robust approach would incorporate these dynamic costs directly into the counterfactuals and the determination of the optimal deviation. Further, our analysis compared expected profits from the observed offer curves to those from an array of specific deviations. In our setting, computing a theoretical benchmark for each firm's optimal bid functions is complicated by the highly nonlinear nature of the residual demand curves which can result in bid functions that are not monotonically increasing.[42] Developing an empirical methodology to characterize a firms' unilateral profit-maximizing best-reply offer curve in the face of multiple local maxima and binding monotonicity constraints is an important subject for future work.

[41]For a detailed discussion of concerns over information disclosure in electricity markets, see von der Fehr (2013).

[42]For a related literature, see Hortaçsu and Puller (2008).

Appendix

A Marginal Cost

We utilize data from the Alberta Market Surveillance Administrator, the Alberta Utilities Commission, and the Alberta Electric System Operator to collect asset-specific heat rates for the natural gas units. Coal unit heat rates were obtained from CASA (2004). We utilize data on the variable O&M costs from the Energy Information Administration (EIA, 2016). We obtained hourly natural gas prices from Alberta's Natural Gas Exchange. Weekly coal prices for Wyoming's Power River Basin (PRB) were utilized to proxy for the fuel input costs for coal units in Alberta. PRB coal is sub-bituminuous coal that is similar in terms of heat-rate content to the coal utilized in Alberta (Alberta Energy, 2014). We utilized Bank of Canada exchange rates to adjust the PRB coal prices and variable O&M costs from USD to CAD.

During our sample period, Alberta's thermal units were subject to the Specified Gas Emitters Regulation that charged units for their emissions intensity (in terms of carbon emissions) above a historical unit-specific benchmark. We utilize the methodology detailed in Brown et al. (2018b) to compute the marginal cost of environmental compliance imposed on coal and natural gas units.

B Supplementary Results

Table A1: Capital Power Change in Expected Hourly Profits (Max. Counterfactual - Observed)

Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	22,183	8,634	33,084	1,172	29,623	125
Q2 (25 - 50)	15,952	2,213	28,073	511	8,521	114
Q3 (50 - 75)	4,986	2,911	7,593	372	5,070	75
Q4 (75 - 100)	2,603	1,841	2,322	737	4,054	109
Non-Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	9,206	1,814	17,827	292	7,924	794
Q2 (25 - 50)	2,174	361	8,068	95	1,109	861
Q3 (50 - 75)	730	186	2,111	29	480	904
Q4 (75 - 100)	538	160	1,279	29	564	884

Table A2: TransCanada Change in Expected Hourly Profits (Max. Counterfactual - Observed)

Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	23,305	9,881	29,774	1,662	46,651	63
Q2 (25 - 50)	5,034	2,188	9,425	64	6,782	89
Q3 (50 - 75)	3,987	2,801	5,889	64	6,188	52
Q4 (75 - 100)	2,083	856	3,211	97	2,599	80
Non-Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	16,650	8,807	21,395	2,666	23,916	566
Q2 (25 - 50)	5,849	1,277	13,734	297	5,116	582
Q3 (50 - 75)	1,641	344	5,043	92	985	497
Q4 (75 - 100)	759	249	1,437	46	993	439

Table A3: Net Demand Estimation Results

	Capital Power	TransCanada
Net Demand$_{t-4}$	0.2313***	0.2306***
	(0.0076)	(0.0077)
Net Demand$_{t-24}$	0.0408***	0.0271***
	(0.0064)	(0.0064)
Net Day-Ahead Forecast$_t$	0.6842***	0.7119***
	(0.0086)	(0.0088)
Constant	-295.3843***	-468.2392***
	(55.5624)	(55.3318)
Observations	4,004	4,004
F-Stat	2,917.27	2,856.83
Calendar Controls	Yes	Yes
R-Squared	0.9255	0.9241

Notes. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table A4: Marginal Effects of the Simple Deviation Strategies by Tag Day and Supply Cushion

	Capital Power (Down $200)		TransCanada (Down $100)	
	Non-Tagged	Tagged	Non-Tagged	Tagged
Supp Cushion Q1	5,600.93***	9,554.33***	1,885.54**	2,536.35*
	(40.47)	(40.61)	(4.75)	(3.09)
Supp Cushion Q2	1,101.82***	5,055.21***	-251.56	399.25
	(10.74)	(13.70)	(0.63)	(0.17)
Supp Cushion Q3	71.90	4,025.30***	107.19	758.01
	(0.45)	(11.69)	(0.30)	(0.64)
Supp Cushion Q4	-313.38**	3,640.02***	102.13	752.94
	(4.17)	(10.21)	(0.37)	(0.75)

Notes. Marginal effects of the baseline model where Capital Power and TransCanada results reflect a unilateral deviation downward of $200 and $100 on its high-priced units in each hour, respectively. F statistics of the Wald Test are presented in parentheses. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table A5: Capital Power Change in Expected Hourly Profits (Max. Counterfactual - Observed) - Dynamic Cost Robustness

Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	20,765	7,998	31,767	673	28,065	125
Q2 (25 - 50)	14,233	1,051	27,020	-149	8,521	114
Q3 (50 - 75)	4,227	2,274	7,312	115	4,382	75
Q4 (75 - 100)	2,115	1,438	2,206	456	3,486	109
Non-Tagged Day						
Supply Cushion Quartile	Mean	Median	Std Dev	25th	75th	N
Q1 (0 - 25)	8,232	1,015	17,652	-24	6,763	794
Q2 (25 - 50)	987	-85	7,503	-635	326	861
Q3 (50 - 75)	-172	-98	2,173	-634	37	904
Q4 (75 - 100)	181	6	1,306	-91	178	884

Table A6: Hourly Industrial Demand Instrumental Variables Estimation

	First-Stage $ln(p_t)$	Second-Stage $Q_t^{Industrial}$
$ln(p_t)$	–	-47.6123***
		(2.4420)
$ln(p_t^{NG})$	1.0532***	13.2054
	(0.3434)	(24.6287)
Capacity Avail.	-0.00102***	
	(0.00014)	
Wind Output	-0.0006***	
	(0.00013)	
$Import_{SK}$	0.0042***	
	(0.0011)	
$Import_{BC}$	-0.0005	
	(0.0003)	
Constant	13.2631***	405.4913***
	(1.2842)	(28.4859)
Observations	4,004	4,004
Kleibergen-Paap F-Stat	90.40***	–
Calendar Controls	Yes	Yes
Temperature Controls	Yes	Yes

Notes. Capacity Available is defined as the available capacity of generation units within Alberta. Import_j reflects import capacity from neighboring province $j \in$ {Saskatchewan, British Columbia}. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table A7: Statistical Test for Simple Unilateral Deviation - Price-Responsive Load Robustness

Variable	Capital Power		TransCanada	
	(1)	(2)	(1)	(2)
Tag Day	3,129.91***	3,178.64**	663.66	710.52
	(1,143.39)	(1,311.33)	(838.64)	(1,107.23)
Supp Cushion Q1	5,071.47***	5,616.83***	2,347.61***	3,133.36***
	(758.14)	(791.82)	(842.38)	(943.55)
Supp Cushion Q2	1,488.84***	1,763.67***	-147.93	243.80
	(442.19)	(515.00)	(240.09)	(439.43)
Supp Cushion Q3	330.89***	362.12**	-65.27	131.28
	(111.47)	(167.68)	(105.90)	(200.83)
Constant	-196.63	-406.70	194.75	428.97
	(139.13)	(628.09)	(143.25)	(887.47)
Observations	3,790	3,790	2,320	2,320
Calendar Controls	No	Yes	No	Yes
F-Stat	13.73***	3.00***	2.48**	1.84***
R^2	0.1071	0.1350	0.0343	0.0803

Notes. Capital Power and TransCanada results reflect a unilateral deviation downward of \$300 and \$100 on its high-priced units in each hour, respectively. Regressions in columns (2) for each firm include time controls for each hour, month, day of week, and holiday. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table A8: Statistical Test for Simple Unilateral Deviation - Forward Position Robustness

Variable	Capital Power			TransCanada		
	90% D200	85% D200	80% D200	80% D100	75% U600	70% U600
Tag Day	3,256.42***	3,095.51***	2,926.38***	223.82	-5,728.72*	-6,064.18*
	(1,155.27)	(1,089.28)	(1,058.36)	(1,060.56)	(2,965.50)	(3,042.19)
Supp Cushion Q1	4,399.39***	3,519.26***	2,883.79***	1,364.41	-1,678.49	-341.58
	(775.92)	(752.04)	(769.57)	(856.19)	(2,053.24)	(2,178.23)
Supp Cushion Q2	1,016.04***	642.58**	361.58	-951.66**	802.38	1,639.68
	(376.15)	(347.19)	(354.78)	(336.06)	(1,359.20)	(1,319.98)
Supp Cushion Q3	272.28**	170.96*	69.36	-201.65	-330.59	-27.80
	(108.32)	(100.69)	(97.23)	(180.72)	(608.57)	(637.67)
Constant	-288.84**	-308.77**	-327.80**	-568.16***	2,236.69***	2,515.15***
	(139.42)	(132.07)	(128.82)	(197.29)	(659.41)	(687.91)
Observations	3,790	3,790	3,790	2,320	2,320	2,320
F-Stat	9.64***	6.69***	5.05***	3.24**	2.95**	2.86**
R-Squared	0.0999	0.0761	0.0602	0.0207	0.0190	0.0191

Notes. The simple deviations entail Down \$200 for Capital Power (D200) and either Down \$100 (D100) or Up \$600 (U600) for TransCanada. Standard errors are presented in parentheses. The residuals are robust to heteroskedasticity and within-day serial correlation. Statistical significance is represented by * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

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