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Evaluating the Impact of Divestitures on Competition: Evidence from Alberta's Wholesale Electricity Market

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by

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Abstract

Asset divestitures play a central role in antitrust and competition policy. Despite their importance, empirical evidence on their impacts on market competition is limited. We analyze market power in Alberta's wholesale electricity market, where transitional arrangements that virtually divested generation assets from large incumbents were put in place during market restructuring in the early 2000's and expired at the end of 2020. Subsequently, average peak hour prices rose by 120% the year after their expiry. We demonstrate that nearly two-thirds of this increase can be explained by elevated market power from the large suppliers. Further, exploiting variation in the allocation of the divested assets across heterogeneous firms, we demonstrate that market power execution is elevated when the divested assets are controlled by large strategic firms. Our findings highlight the important role that asset divestitures and their allocations can have on market competition. Our analysis also raises concerns over the ability of restructured electricity markets to facilitate sufficient competition through entry and the potential need for regulatory intervention.

Keywords: Electricity, Market Power, Competition Policy, Divestitures
JEL Codes: D43, L13, L50, L94, Q40

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1 Introduction

Competition and antitrust authorities can have an important impact on shaping the structure of markets. Prominent examples include structural remedies that require firms to divest assets in proposed merger and acquisition cases in Europe and the United States.[1] Mandated divestitures also played a critical role during the initial phases of market restructuring in the electricity sector. In particular, the introduction of competition involved transitional arrangements to ensure the heavily concentrated markets did not lead to excessive market power or impede the development of competition. These policies often involved breaking up firms' vertical arrangements (i.e., generation from transmission and distribution) and forced generation asset divestitures to reduce wholesale market concentration (Borenstein and Bushnell, 2015).

Despite the widespread use of divestitures in competition policy, empirical evaluations of their impacts are limited. In this paper, we consider the case of the Alberta electricity sector, where the government chose a path of *virtual divestitures* to facilitate restructuring through the creation of 20-year Power Purchase Arrangements (PPAs).[2] The PPAs effectively acted as a lease on the generation units, allowing the holder to choose both the price and quantity offered into the wholesale market, while the original owner maintained physical operation. These virtual divestitures expired at the end of 2020 and the offer control of these assets reverted back to their original owners leading to a large increase in market concentration. In addition to this large change in market structure, the holders of the PPAs varied throughout our sample. In particular, starting in 2016 the PPAs were transferred from large strategic firms to a government entity called the Balancing Pool.[3] The Balancing Pool offered these units at short-run marginal cost, as if it were a perfectly competitive firm. This provides us with unique variation to identify how the allocation of divested assets to heterogeneous firms can impact market outcomes.

Alberta's electricity market has a regulatory framework that places limited restrictions on firm behaviour. This provides us with an ideal environment to analyze market power. We use detailed data from the Alberta Electric System Operator (AESO) for the period 2013 - 2021 that includes price and quantity wholesale market bids from all generators at the hourly level. We also have detailed data from various sources that allow us to estimate the short-run marginal cost of each generation unit. We use these data to construct a counterfactual "competitive benchmark" that represents the market outcome if all firms behaved as price-takers in the hourly uniform-priced wholesale procurement auction. This allows us to compare the competitive counterfactual to

[1] Mergers with divestiture requirements have occurred in numerous industries ranging from consumer health products (Tenn and Yun, 2011), grocery stores (Cotterill et al., 1999), oil & gas (Rogers and Hollinger, 2004), beer markets (Friberg and Romahn, 2015), electricity (McRae and Wolak, 2009; Ausubel and Cramton, 2010), among others.

[2] Similar virtual divestitures were introduced in a number of European countries including Britain, Belgium, the Netherlands, Denmark, Spain, Portugal, France, and Germany (Ausubel and Cramton, 2010; de Frutos and Fabra, 2012).

[3] See Section 2 for a detailed discussion on the PPAs, including a timeline and summary of the reasons for the PPA transfer to the Balancing Pool.

realized equilibrium outcomes to quantify changes to the extent of market power over time and to consider how these changes relate to changes in offer control over the PPAs.

We find that the expiry of the PPAs in 2021 corresponded with a substantial increase in the degree of market power execution. Of the \$70/MWh increase in average peak-hour prices from 2020 to 2021, representing a 120% increase in prices, we find that approximately 63% is due to firms raising their offer prices above marginal cost. The increase in market power that corresponds with the expiry of the PPAs remains when we focus on a narrow window around the expiry event, during which there were no other changes to the configuration of generation assets in the market. Similarly, we demonstrate that the high prices that occurred early in our sample were the result of strategic behaviour. This arises despite the fact that virtual divestitures existed to reduce market concentration. We show that this market power arises because the PPAs were offered into the market by large strategic firms.

We show that starting in 2016 until the expiry of the PPAs, market outcomes more closely reflected the competitive counterfactual. These more competitive outcomes reflect a combination of two forces. First, overall market conditions became less tight as a large natural gas unit entered the market. Second, driven in part by the entry of new generation and low prices, the divested assets were transferred to the Balancing Pool, a firm that offered these units at prices near their marginal cost. We use several empirical methods to demonstrate that market power execution is distinctly higher in the periods in which the PPAs were offered by large strategic generators, controlling for prevailing market demand and available generation capacity.

We complement these market-level results with a firm-level analysis. We demonstrate that the allocation of the PPA assets resulted in several large firms becoming "pivotal" (i.e., necessary to clear the market). Further, we use methods developed by Wolak (2000) to quantify the generators' ability and incentive to exercise unilateral market power based on the properties of the residual demand function each firm faces. Both of these analyses demonstrate that the large generators had a significant ability to exercise market power over certain periods. This ability was mitigated when the PPAs were offered by the Balancing Pool. We examine firm-level bidding behaviour and find that the generators that had offer control over the PPAs were the generators that typically exercised market power, coinciding with periods in which there were elevated wholesale prices.

Our findings illustrate that virtual divestitures can have a substantial impact on market outcomes. When these assets are offered by large firms, either by their original owners after expiry or when the PPAs were allocated to large oligopolists, market prices exceed the competitive counterfactual by a considerable margin. We demonstrate that this leads to a considerable transfer of rents from consumers to producers. Our findings highlight that structural remedies in the form of asset divestitures can serve an important role in reducing short-run market power in concentrated electricity markets, but the allocation of these assets is critically important.

Our analysis provides a number of contributions to the literature. First, structural remedies that include asset divestitures are the dominant tool employed by the United States Department of

Justice and the European Commission in merger cases (DOJ, 2020; Maier-Rigaud and Loertscher, 2020). Despite their dominant role, there are relatively few studies that quantify the impacts of asset divestitures. Competition agencies have carried out a number of descriptive studies that detail different divestiture cases and approaches, including in the United States (FTC, 1999, 2017), Canada (Competition Bureau Canada, 2011), and the United Kingdom (PwC Economics, 2005).

There is an emerging literature that carries out empirical *ex-post* analyses of merger cases with divestitures. These studies consider several industries including the Johnson & Johnson acquisition of Pfizer's customer health division (Tenn and Yun, 2011), licenses for highway retail gasoline stations held by the Dutch government (Soetevent et al., 2014), a merger in the Swedish beer market (Friberg and Romahn, 2015), and a merger of casinos in Missouri (Osinski and Sandford, 2020). These studies often find that the divestitures were successful at mitigating the price increasing impacts of the mergers. Soetevent et al. (2014) and Friberg and Romahn (2015) find that the divested products set lower prices and have competitive spill-over effects. Osinski and Sandford (2020) find that while prices were lower post-merger, the authors attribute this to realized efficiencies and find the divested casino performance decreased post-merger.

In addition to providing among the first empirical evaluation of the effects of asset divestitures on market competition in the electricity sector, our setting provides us with unique advantages.[4] The four empirical studies cited above primarily rely on a difference-in-difference (DID) empirical framework to evaluate the impacts of mergers and asset divestitures on market prices.[5] Davies and Ormosi (2012) highlight empirical challenges with this approach because the control group includes non-merging rivals which are likely to be exposed to spill-over competition effects post-merger. This makes it difficult to find a clear control group in a DID framework. A unique advantage of analyzing the electricity sector is our ability to estimate the marginal cost of production using a well-established engineering formula.[6] We are able to directly infer how the degree of market power varies over time, controlling for changes in underlying supply and demand conditions, by constructing a competitive counterfactual benchmark. Further, we observe the transfer of the divested assets to heterogeneous firms over time. This allows us to estimate the impact of variation in divested asset ownership on market outcomes.

Our analysis adds to the large body of work that analyzes and documents the presence of market power in wholesale electricity markets (e.g., Wolfram, 1999; Wolak, 2000, 2003; Borenstein et al., 2002; Mansur, 2007; Bushnell et al., 2008; Reguant, 2014; Brown and Olmstead, 2017).

[4] Wolfram (1999) and Green (1999) analyze market competition in the British electricity market in the early 2000's. The two largest generators were required to divest 10% - 15% of their capacity. However, unlike our setting which lacked additional regulatory restrictions, the firms also agreed to adhere to a price cap that suppressed their bids in the wholesale market. Weigt and Willems (2011) and Brown and Eckert (2017, 2018) employ simulation studies that analyze the impact of asset divestitures in wholesale electricity markets.

[5] Friberg and Romahn (2015) also develops a structural random logit coefficients demand model and Soetevent et al. (2014) employ an instrumental variables approach to evaluate the robustness of their DID estimators.

[6] Kim and Knittel (2006) use this unique feature of electricity markets to evaluate the accuracy of structural models in the empirical industrial organization literature. See also Wolak (2010) for a discussion of this and other features of electricity markets that facilitate empirical analysis of firm conduct and market power.

While the precise methods, applications, and objectives of these studies differ, they all present empirical evidence that electricity markets are susceptible to market power. We follow the work of Borenstein et al. (2002), Mansur (2007), and Brown and Olmstead (2017) and use a competitive benchmark approach to quantify strategic behaviour.[7]

Our work also relates to two recent contributions that use variation in transmission capacity constraints to identify the relationship between market structure and market power (McDermott, 2020; Woerman, 2021). Both studies use quasi-experimental empirical strategies and find a strong relationship between market concentration and market power. Unlike their setting, which relies on temporary hourly variation in transmission bottlenecks, our analysis focuses on large persistent changes to Alberta's market structure as the result of virtual asset divestitures.

Finally, our analysis contributes to the literature that analyzes the impacts of fixed-priced forward contracts on competition (e.g., Allaz and Vila, 1993; Bushnell et al., 2008). When a generator holds a forward contact, it has the incentive to bid the associated quantity covered by that contract at or below short-run marginal cost (Hortacsu and Puller, 2008). Consequently, the transfer of the PPAs from the strategic PPA buyers to the Balancing Pool, which bids these assets in at marginal cost, could be viewed as the PPA buyers entering into a forward contract that is proportional to the size of the PPA units. Then, when the PPAs expired, these forward contracts were removed.

Consistent with the forward contracting literature, we observe a reduction in market power as the PPAs were transferred to the Balancing Pool and then elevated market power when the PPAs expired. This behaviour is consistent with the empirical literature demonstrating the pro-competitive impact of forward contracts (Wolak, 2000; Bushnell et al., 2008). However, the PPAs differ from standard fixed-priced forward contracts in two key ways. First, the PPAs were effectively a lease on the units to other generators and placed no restrictions on the bids on the unit. As a result, the holder of the PPAs chose whether the asset would generate electricity, and if so, how much. The forward contracting analogy is a result of the Balancing Pool's bidding behaviour given its interpretation of its mandate by the government. Second, forward contracting decisions are endogenous. We anticipate that the generators adjusted their broader forward contract positions in response to changes in the PPA allocation.[8] Therefore, we are unable to make assertions about the overall level of forward contracting in the market as the allocations of the PPAs varied.

Our analysis proceeds as follows. Section 2 describes features of Alberta's electricity market

[7]There is an emerging literature that highlights the importance of considering dynamic costs associated with turning-on and ramping up output from generation facilities (Mansur, 2008; Reguant, 2014; Jha and Leslie, 2021). The static marginal cost approach in our analysis does not account for these costs. However, the focus of the current paper is not on a precise estimate of the degree of market power, but rather to examine how market power has varied over time with changes in the offer control over the PPAs. As well, to address the potential for dynamic costs, we conduct an additional analysis over a narrow window of time around the expiry of the PPAs at the end of 2020, during which there were no changes to the generation portfolio that would have affected dynamic costs.

[8]Brown and Eckert (2017) and Miller and Podwol (2020) develop a model to demonstrate that firms adjust their forward positions as the market structure changes.

and how it has evolved over time, including a detailed discussion and timeline of the PPAs. The data are detailed in Section 3. Section 4 summarizes our empirical methodology. Results are presented in Section 5. Section 6 concludes.

2 Background

2.1 Alberta's Restructured Electricity Market

In 1996, Alberta began restructuring its electricity market, which until then consisted largely of vertical integrated utilities with franchise (locational) monopolies.[9] The process started with the introduction of the *Electric Utilities Act* (EUA), which set in motion steps that would form the basis of the competitive markets Alberta has today for generation and retail provision of electricity.

The wholesale market created under restructuring is conducted as a single hourly real-time uniform-priced auction. For each hour, firms submit up to seven price-quantity offer blocks for each generating asset over which they have offer control. Each block indicates the price at which the firm would be willing to supply the quantity in the block. Offer prices must be between $0/MWh and $999.99/MWh. Firms are required to offer all available capacity for each asset. Throughout each hour, offer blocks are called upon in increasing order of price to meet market demand. The price of the last block needed becomes the System Marginal Price (SMP). Generating units are compensated for their output in the hour according to the time-weighted SMP for the hour, referred to as the Pool Price.

Alberta's wholesale electricity market is "energy-only", meaning that firms do not receive separate payments for building or maintaining generating capacity, and must rely on compensation for the electricity generated to cover variable and fixed costs.[10] For this reason, the Market Surveillance Administrator (MSA) that is responsible for monitoring electricity markets in Alberta has indicated that the unilateral exercise of market power through "economic withholding", or submitting offer blocks with high prices to ensure they are not called upon, is permitted (MSA, 2011, 2020). This is in contrast to numerous jurisdictions that impose policies that regulate how far firms' bids can deviate from marginal cost (Graf et al., 2021), making our setting ideal to analyze market power.

Prior to Alberta's restructuring, three utilities (TransAlta, ATCO, and EPCOR) owned approximately 90% of generation capacity in the province (with approximately 75% of the capacity owned by these utilities being coal-fired).[11] To address this level of concentration and corresponding concerns about excessive market power, amendments to the EUA passed in 1998 introduced the Power Purchase Arrangements (PPAs). The PPAs were long-term (up to 20 years) contracts between the owners of existing generation and the PPA buyers, under which the PPA buyers obtained the rights to

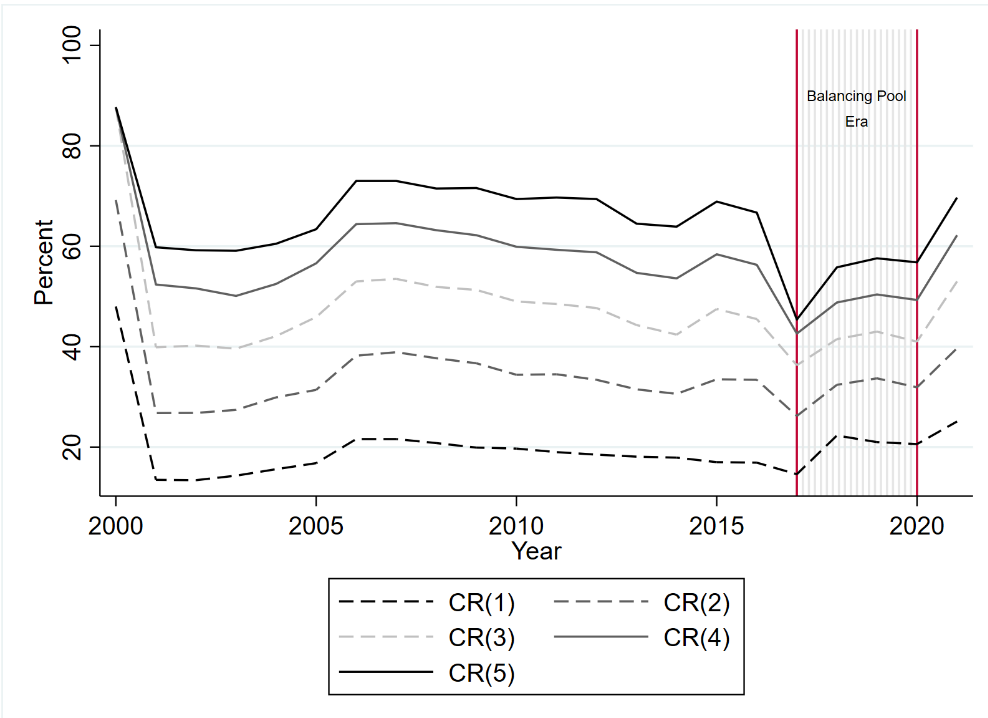
[9]Detailed discussions of electricity restructuring in Alberta can be found in Daniel et al. (2007) and Nicolay (2011).

[10]The majority of restructured markets in North America have capacity mechanisms that compensate generators for their capacity reflecting their capability to generate electricity (Bushnell et al., 2017).

[11]Information in this section on market structure before the introduction of the PPAs, and the generating units involved in the PPAs, comes from Daniel et al. (2007) and Kendall-Smith (2013).

offer the output of the generating unit into the power pool (referred to as "offer control"). These contracts represented a virtual divestiture of the generation unit, and were intended to facilitate increased competition in the wholesale market. The PPA owner maintains operational control and is compensated by the buyer to cover the short-run variable costs and to ensure the owners receive their pre-deregulation rate-of-return (Leach and Tombe, 2016).

Figure 1: One-to-Five Firm Concentration Ratios, 2000-2021



The PPAs were sold through auctions held in 2000. Of the 6,250 MWs of coal and gas-based capacity offered in these auctions, representing approximately 64% of total capacity in 2000, 4,254 MWs were purchased. The PPA contracts that were not purchased were offered into the wholesale market by the Balancing Pool, an entity created by legislation to act as the buyer for 790 MW of hydroelectric PPAs, all unsold thermal PPA capacity, and to manage the transfer of net revenues from the PPA auctions on to consumers (Balancing Pool, 2015). Under the *Electric Utilities Act*, the responsibilities of the Balancing Pool included the duty to "manage generation assets in a commercial manner". In particular, there were no regulatory requirements placed on the offer prices (e.g., at marginal cost) for assets under the control of the Balancing Pool.

The dramatic drop in wholesale market concentration resulting from the introduction of the PPAs can be seen in Figure 1, which plots the combined market shares, based on offer control, of the one-to-five largest firms, annually for the period 2000 to 2021.[12] Note that in Figure 1, the

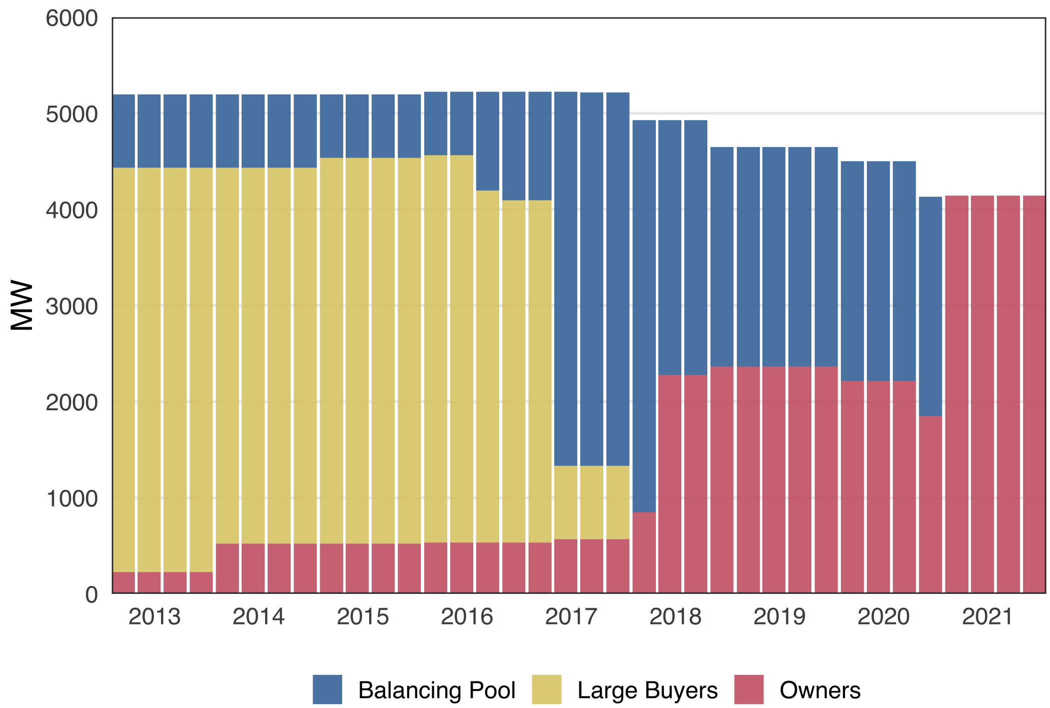
[12]Data for the years 2000 - 2012 come from Kendall-Smith (2013); data for 2013 - 2021 are taken from the MSA's annual offer control reports, available at https://www.albertamsa.ca/documents/reports/msoc/. Because Kendall-Smith (2013) reports market shares for only the largest firms, we are unable to calculate Herfindahl-Hirschman Index (HHI) statistics for the period covered in the figure.

Balancing Pool is not counted among the large strategic firms because of its unique competitive behaviour detailed below. Concentration ratios declined abruptly with the introduction of the PPAs; for example, in 2001, the year following the introduction of the PPAs, the combined offer control of the three largest firms fell from nearly 90% to 39%.[13]

2.2 Evolution of Wholesale Market Structure

The market structure has evolved substantially in the years since restructuring. In particular, offer control over the PPA assets has changed since the initial auctions. Certain PPAs that initially were under the offer control of the Balancing Pool were sold in 2005, while other PPA assets were retired. By 2013 (the beginning of our sample period), thermal generating assets subject to PPAs accounted for 5,198 MW of capacity representing 37% of market capacity (MSA, 2013). Of this, offer control of 227 MW was held by the owners of the generating assets, 4,209 MW was held by the PPA buyers, which were large strategic firms (Capital Power, TransCanada, and ENMAX), and 762 MW was under the offer control of the Balancing Pool. The breakdown of offer control of these assets into these three categories is illustrated for the years 2013 - 2021 in Figure 2.

Figure 2: Offer Control of PPA Generating Assets, 2013-2021 (Quarterly)



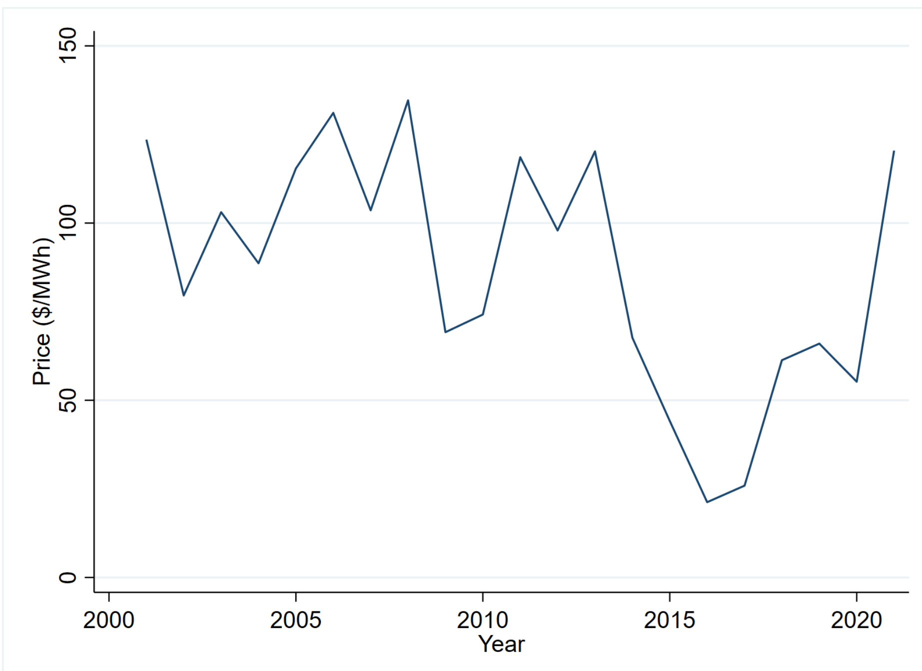
Pool prices fell dramatically in 2015 as new large-scale natural gas generation entered the market; see Figure 3 for a plot of pool prices (in 2021 dollars) from 2001 to 2021. At the same time, amendments to Alberta's *Specified Gas Emitters Regulation* in 2015 strengthened the carbon

[13]Note that in the time period following restructuring, the three largest firms were typically not the initial three utilities. For example, in 2013 the three largest firms were TransCanada, TransAlta, and ENMAX.

pricing faced by large industrial firms and increased the costs of operating coal-fired generators.[14] PPA buyers were able to exit a PPA without penalty "if a Change in Law renders the PPA unprofitable, or more unprofitable" (Alberta Energy and Utilities Board, 2000), and over Winter 2015 and Spring 2016 all PPA buyers announced that they were "terminating" their PPA contracts, which would transfer offer control of the PPAs to the Balancing Pool.

There was a debate over whether the PPA terminations were legal, with a legal challenge brought forward by the Government of Alberta in mid-2016; as a result, the transfer of offer control of the PPAs to the Balancing Pool was delayed. While the first PPA was transferred in July 2016, all but two of the remaining transfers to the Balancing Pool occurred in January 2017.[15] This led to a transitionary period in 2016 in which the PPAs were still offered by the PPA buyers, but the PPAs had been terminated. Interestingly, it was noted that over this period, the PPA buyers offered these units in at marginal cost (MSA, 2018).[16] Throughout our analysis, we will refer to 2016 as a transition period to acknowledge the unique aspects of this time period.

Figure 3: Pool Prices (in 2021 CAD$s), 2001-2021



The Balancing Pool's conduct over this time period was the subject of an investigation by the Market Surveillance Administrator, who alleged that it had violated the *Electric Utilities Act*.[17]

[14]See Olmstead and Yatchew (2022) for a detailed discussion of the evolution in Alberta's environmental regulations and subsequent decline in coal-fired generation.

[15]The final PPAs were transferred in December 2017. For details, see Leach and Tombe (2016) and AUC (2019).

[16]Whether this pricing reflects unilateral profit maximizing behaviour in a time of low prices and large capacity relative to demand, or whether it is indicative of some form of strategic behaviour on the part of the PPA buyers, is a question for future research.

[17]In addition, the MSA alleged that the Balancing Pool violated its *Balancing Pool Regulation* because it "declined to or did not promptly assess and verify the validity of the terminations of the Five PPAs and did not unconditionally

In particular, the MSA alleged that by not immediately terminating certain unprofitable PPAs and returning control to the owner, the Balancing Pool was not operating them in a commercial manner; we will discuss possible implications of this allegation for our empirical analysis in Section 4.1 below. As well, the MSA raised concerns about the Balancing Pool's "variable cost offer strategy" of offering its PPA capacity into the wholesale market at short-run marginal cost.[18] The resulting settlement agreement, approved in 2019, required the Balancing Pool to "consider the full range of commercial activities open to market participants,"(MSA 2018, p.10) such as forward sales and provision of ancillary services, but placed no restrictions on its offer behaviour.[19]

The transfer of PPA capacity from the original buyers to the Balancing Pool represented an important shift of market share from large firms to an entity with a practice of offering its capacity at marginal cost. By April 2017, the Balancing Pool had offer control over 24.5% of Alberta generating capacity, while the combined market share of the five largest firms (excluding the Balancing Pool) had fallen to 45.4%, compared to 68.9% in 2015. This transition to the "Balancing Pool Era," highlighted in Figure 1 and shown in Figure 2, can be thought of as a reallocation of the divested capacity from large strategic firms to a competitive fringe, or alternatively, as the PPA capacity being subject to a fixed-price forward contract (holding all else constant).

Figure 2 demonstrates that the total capacity of PPA assets started falling in 2018, as several coal assets were retired. By 2021, the proportion of Alberta capacity that was coal-fired had fallen to 21%, from 58% before restructuring. Upon expiry of the PPAs on December 31, 2020, the offer control of the remaining PPA assets returned to their original owners, resulting in offer control of over 2,284 MWs (15% of generating capacity) being returned to large strategic firms (TransAlta, Capital Power, and Heartland). As illustrated in Figure 1, this transfer of capacity from an entity behaving as a competitive fringe to the large PPA owners increased concentration substantially. Figure 3 shows that this transfer coincided with an increase in average pool prices in 2021 back to levels observed in 2013 and earlier. Taken together, these changes led to three different market regimes where the PPAs were offered into the market by (i) large strategic buyers (2013 - 2016), (ii) the Balancing Pool (2016 - 2020), and (iii) the original owners (2021).

3 Data

Our analysis considers the period January 1, 2013 - December 31, 2021.[20] We use several publicly available data sets. First, we use hourly data from the Alberta Electric System Operator

assume the buyer role on a timely basis with respect to those PPAs" (MSA 2018, page 7).

[18]As noted in Daniel et al. (2007), the Balancing Pool's marginal cost offer strategy was observed as early as 2001.

[19]By examining the transfer of PPA offer control to the Balancing Pool, our paper also contributes to the literature on "mixed markets" in which private firms compete against public firms. While there is a large literature analyzing mixed market competition, it is largely theoretical (e.g., De Fraja and Delbono, 1990; Escrihuela-Villar et al., 2020). Our work contributes to the limited empirical literature assessing the impact of mixed market competition on equilibrium outcomes (Emmons III, 1997; Epple et al., 2004; Adler and Liebert, 2014; Suarez, 2021).

[20]Prior to 2013, the data on individual firm bidding behaviour does not include information on offer control. This limits our ability to go back further in time.

(AESO) that includes the observed price and quantity bids for all generation units, the offer control of each unit, import supply from neighboring provinces, import transmission line capacity, and observed market demand.[21] Second and third, we employ daily natural gas price data made available by the Alberta Natural Gas Exchange (NGX) and weekly Powder River Basin coal price data provided by the U.S. Energy Information Administration.[22] Fourth, generation unit-level efficiency parameters were acquired from documents published by the MSA, Alberta Utilities Commission, and CASA (2004). These data will be used to compute the cost of fossil-fuel generation. Fifth, weather data for cities in neighboring jurisdictions Saskatchewan, British Columbia, and Montana were accessed from Environment Canada and the National Oceanic and Atmospheric Administration. Sixth and seventh, we use electricity demand data from the Bonneville Power Administration (BPA, 2022) and Mid-Columbia peak wholesale prices from the U.S. Energy Information Administration (EIA, 2022). The data from the last three sources will be used to proxy for electricity supply and demand conditions in neighboring jurisdictions to capture import and export decisions.

Table 1 presents summary statistics for several key variables that are utilized in our analysis. This table demonstrates that there is considerable variation in demand, fuel costs, and wind output. This contributes to the wide dispersion in the market-clearing price which ranges over the full range of allowable offer prices. Further, while there are hours in which net imports are negative, Alberta observes positive net imports in the majority of hours and has positive average net imports.

Table 1: Summary Statistics

Variable	Units	Mean	Std. Dev	Min	Max
Market-Clearing Price	$/MWh	62.21	130.44	0.00	999.99
Market Demand	MWh	9,545.61	1,037.12	6,011.00	11,847.00
Net Imports	MWh	254.16	332.28	-935.00	1,245.00
Wind	MWh	493.76	403.88	0.00	1,933.42
Coal Price	$/Short Ton	14.82	3.66	10.02	39.33
Gas Price	$/GJ	2.52	1.11	0.05	16.00

Notes. This table focuses on peak hours (6:00 AM - 10:00 PM). $ values represent Canadian Dollars. Our sample covers years 2013 - 2021 representing 52,556 peak hours.

4 Empirical Methodology

Our analysis focuses on peak hours ranging from 6:00 AM to 10:00 PM, the hours in which market power is most likely to occur.[23] We compare observed outcomes to a perfectly competitive

[21] AESO data can be accessed at: http://ets.aeso.ca/.

[22] Powder River Basin Coal price can be accessed at: https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region. NGX gas price data were provided to the authors by the Alberta Market Surveillance Administrator.

[23] We summarize the results for the remaining off peak hours briefly in Section 5.1.

benchmark that would arise if all generation was bid into the market at marginal cost. We use this competitive benchmark to evaluate the degree of market power and rent transfers as the result of strategic bidding over time.[24] The analysis is carried out as follows. First, we estimate the marginal cost of each generation unit and simulate unit availability using a Monte Carlo simulation approach to account for the fact that asset availability is potentially endogenous. Second, we estimate a price-responsive net import supply function to formulate the residual demand faced by generators within Alberta. Third, we estimate the competitive counterfactual price that arises where the market-level marginal cost function intersects the estimated residual demand. Fourth, we compare the observed and competitive counterfactual outcomes to compute measures of market power.

4.1 Market Power Measures

Figure 4 provides an illustrative example of our empirical methodology. The market-level offer curve is formed by stacking generators' offers in order of least-cost. Residual demand reflects price-inelastic demand minus price-responsive net imports. The observed market-clearing price (P^{Obs}) and quantity (Q^{Obs}) are determined by the intersection of the offer curve and residual demand. A competitive counterfactual is constructed to quantify the consequences of market power. MC^{Comp} represents the perfectly competitive counterfactual supply function that would emerge by ordering available generation units in terms of their marginal cost. The competitive price (P^{Comp}) and quantity (Q^{Comp}) are determined by the intersection of the competitive supply function and residual demand. The difference between the observed and competitive quantities arise from a substitution of net imports for production by units within Alberta.[25] Q^{MR} represents must-run supply (e.g., wind) that arises exogenously.

We use a number of measures to quantify the impacts of strategic behaviour on market outcomes. For each hour, we compare the observed and competitive counterfactual prices. We will define this difference as the markup above the perfectly competitive price. In addition, for any set of hours $\mathcal{T}$, we evaluate the overall market performance as follows:[26]

$$MP(\mathcal{T}) \; = \; \frac{\sum\limits_{t \in \mathcal{T}} \left(P_t^{Obs} - P_t^{Comp} \right) \overline{Q}_t}{\sum\limits_{t \in \mathcal{T}} P_t^{Obs} \, \overline{Q}_t} \tag{1}$$

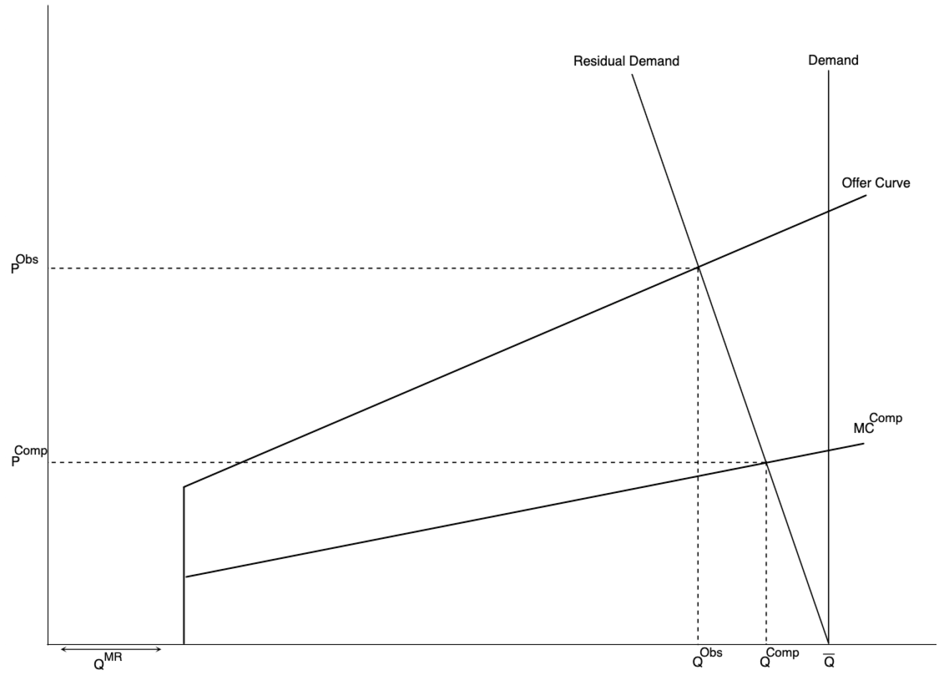
where $\overline{Q}_t$ is the observed perfectly price-inelastic market demand, and P_t^{Comp} and P_t^{Obs} are the competitive and observed market-clearing prices. This market performance measure reflects the

[24] A similar approach to evaluating the degree of market power in wholesale electricity markets is employed in Wolfram (1999), Borenstein et al. (2002), Puller (2007), Mansur (2007), and Brown and Olmstead (2017).

[25] In our empirical analysis, we account for the presence of net import transmission capacity constraints. At sufficiently high prices, net import capacity constraints bind causing residual demand to become vertical. However, our empirical method remains unchanged as we continue to solve for the intersection of observed and competitive counterfactual supply and residual demand.

[26] Borenstein et al. (2002) use a similar measure to define market performance.

Figure 4: Illustration of Empirical Methodology and Market Power



excess costs of wholesale procurement divided by the observed wholesale procurement costs. A larger value on $MP(\mathcal{T})$ indicates a higher degree of market power execution.

We compute measures that represent the excess producer surplus and productive inefficiencies to understand the distributional consequences of market power. Variable producer surplus represents total payments minus variable production costs. Producer surplus still arises in the competitive counterfactual because the market-level marginal cost function is convex and the auction is uniform-priced. Excess producer surplus represents the difference between the variable producer surplus in the observed and competitive benchmark. We estimate productive inefficiencies that represent the change in the total variable cost of production under the observed outcome compared to the competitive counterfactual. Productive inefficiencies arise from the substitution of lower cost production for higher cost supply due to the execution of market power. This measure reflects the deadweight loss in our setting because demand is perfectly price-inelastic.[27]

Throughout our analysis, we will report all values in real terms in 2021 Canadian dollars.[28] Note that our analysis does not account for the (large) fixed costs associated with generation facilities. Since our main objective is to compare surplus under the observed and competitive outcomes, fixed costs are removed in the differencing. We discuss the importance of fixed cost and its implications in Section 6.

[27] To undertake this calculation, we follow Borenstein et al. (2002) and assume that importers into the province are price-takers. Under this assumption, the estimated import supply function detailed in Section 4.3 represents the marginal cost of providing import supply. To the extent that importers are not price-takers, this will attribute rent transfers from consumers to importers as productive inefficiencies.

[28] We use Statistics Canada's Alberta All-Items Consumer Price Index (Table 18-10-0004-01).

One challenge with comparing market power execution across years is the changing market conditions. To provide a comparison of the degree of market power for any given level of market "tightness", we use the hourly *supply cushion* which is the total generation capacity available minus market demand.[29] The supply cushion measure will be used in several reduced-form regressions. In these regressions, we compute an *expected* supply cushion measure that equals expected generation capacity minus market demand to account for the potential endogeneity of unit availability.[30]

We compute the value of our market performance measure in (1) for every hour t. This yields a measure that is closely related to a Lerner Index that equals the difference between the observed and competitive price, divided by the observed price. For several key years, we run a kernel regression of the hourly Lerner Index on the expected supply cushion to understand how the degree of market power execution varies with this important measure.[31]

We supplement this kernel regression with a reduced-form regression of the hourly Lerner Index (LI_t) on year dummies $D_{y,t}$ and year dummies interacted with an indicator variable for each expected supply cushion quartile (Supply Cushion $\text{Q}j_t$ for $j = 1, 2, 3, 4$):

$$\begin{aligned} LI_t \;=\; \sum_{y=2013}^{2021} \Big\{ & \gamma_y \, D_{y,t} + \beta_y \, \text{Supply Cushion Q1}_t \cdot D_{y,t} + \alpha_y \, \text{Supply Cushion Q2}_t \cdot D_{y,t} \\ & + \omega_y \, \text{Supply Cushion Q3}_t \cdot D_{y,t} \Big\} + \epsilon_t \end{aligned} \tag{2}$$

where the fourth quartile of the expected supply cushion is the excluded indicator and ϵ_t is the error term. The objective of this regression is to describe the relationship between the expected supply cushion and market power over time, rather than make assertions of causality. This will provide insights into whether this relationship has changed when, for example, the PPA units were under the control of the Balancing Pool rather than the strategic buyers or PPA owners. We estimate this regression using Newey-West robust standard errors with 24 hour lags to control for serial correlation.

While the reduced-form regressions describe the relationship between the market power measures and the tightness of the overall market, other features can impact firms' abilities and incentives to exercise market power. We employ an approach in the literature that establishes a measure to quantify the ability and incentive of a generator to unilaterally exercise market power (Wolak, 2000, 2003; McRae and Wolak, 2014). The modeling framework relies on the principle that a generator's ability to exercise market power depends on the properties of the residual demand

[29] Brown and Olmstead (2017) find that the degree of market power can be well-explained by the supply cushion, with elevated market power in hours with a low supply cushion.

[30] More specifically, for thermal generation units, we compute a year-month-hour specific average available capacity measure to eliminate the possible endogeneity of asset ability on any given day, but to capture broader unit availability trends. We then compute the supply cushion using this lower-frequency thermal capacity measure and high-frequency hourly demand and must-run technology outputs (e.g., wind) that are assumed to be exogenous.

[31] Following Borenstein et al. (2002), we truncate negative values of the Lerner Index to zero when estimating the kernel regression to deal with the fact that this measure is not symmetric around zero.

function it faces, where residual demand in this framework equals market demand minus its rivals' supply offers. We use this measure to summarize how the strategic environment facing the large firms changed over time as the allocation of offer control over the PPAs varied. Details of the empirical approach are summarized in Appendix E.

Before proceeding, we discuss several features of our methodology that warrant additional clarification. There are cases where the markup $P_t^{Obs} - P_t^{Comp}$ is negative. A profit-maximizing firm would not be willing to sell output at prices below their *true* marginal cost. These negative markups are likely driven by two factors. First, it is possible that we have some degree of measurement error in our short-run marginal cost estimates. To minimize these concerns, we use a well-established empirical methodology employed in the literature (e.g., Wolfram (1999), Borenstein et al. (2002), Wolak (2003), Kim and Knittel (2006)), coupled with values on unit heat rates submitted to regulatory agencies.[32] Improvements in unit efficiency and the potential over reporting of cost to regulators may lead to our marginal cost estimates as being viewed as overestimates (Borenstein et al., 2002). Overestimation of marginal cost will bias our market power estimates downward.

Second, we do not account for the presence of dynamic costs associated with starting up and adjusting unit output, as well as minimum down times. Prior research has demonstrated that dynamic costs can have an impact on production decisions and static marginal cost-based analyses (e.g., Mansur, 2008; Reguant 2014; Jha and Leslie, 2021). As noted by Borenstein et al. (2002), the presence of dynamic costs can impact static market cost measures in both directions by creating an opportunity cost of both shutting down and starting up generation facilities. The primary goal of our analysis is to focus on how market power and firm behaviour varies over time. We focus on peak hours to reduce the potential presence of dynamic costs that are more likely to be a consideration in off-peak periods when units are making their start-up decisions. Further, we carry out an additional analysis that considers the short time period before and after the PPA expiry on January 1, 2021, where the dynamic costs and unit operational constraints are unchanged. In the analysis below, we will discuss how dynamic costs could impact our key conclusions.

Finally, rec all from Section 2 that following the transfer of the PPAs to the Balancing Pool in 2016 - 2017, allegations were made that the Balancing Pool failed to operate the "unprofitable PPAs" in a commercial manner by not immediately terminating them and returning control to the owners. As shown in a financial audit of the Balancing Pool over this time period, Deloitte (2021) find that this unprofitability reflects the recovery of capacity-based costs, not insufficient recovery of the variable costs. This raises the possibility that the presence of these assets during 2017 and afterwards was a function of which entity had offer control over them. While this could have implications for an analysis of the long-run implications of divestiture of assets to different firms, our primary focus is on the short-run effects; conditional on the PPA assets being used, we analyze how short-run market outcomes depend on the firms to which they are divested. More broadly, our analysis abstracts from long-term considerations such as entry and exit at the market-

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

level and instead focuses on the relationship between the short-run market structure and market power. Section 6 acknowledges the importance of future research that considers the longer-term implications of the PPA divestitures.

4.2 Marginal Cost and Unit Availability

There are a number of different generation technologies operating in Alberta. Each technology has its own unique features that require different approaches to estimating marginal cost. We categorize the units into three types: (i) fossil-fuel units whose marginal costs can be estimated using a standard engineering formula, (ii) renewable technologies that have no fuel costs, and (iii) cogeneration, biomass, and hydro units whose costs are inferred from their bidding behaviour.[33]

We estimate the marginal cost of natural gas and coal generation units using the summation of fuel input cost, costs of environmental compliance, and variable operating and maintenance (O&M) cost. Fuel input costs are determined by the fuel price (e.g., coal or natural gas) multiplied by the unit-specific efficiency measured by an asset's heat-rate.

Wind and solar generation has been increasing in Alberta over the last decade. The output from these technologies are exogenously determined by factors such as weather and is considered to be must-run. The marginal cost of production from these units is set equal to \$0/MWh, which is equal to the price floor in the wholesale market.

The remaining technologies have unique characteristics. A sizable proportion of electricity produced in the province comes from primarily natural gas cogeneration facilities. Cogeneration units generate electricity as a byproduct of an on-site industrial process (e.g., oil sands) and sell the excess electricity to the wholesale market. These units systematically bid in this output at a price of \$0/MWh, or a small amount of supply at a high price (e.g., in excess of \$990/MWh).[34] We set the marginal cost of cogeneration at their bid price, which is \$0/MWh for 95% of cogen supplied into the market.

There are several biomass units in the province that are owned and operated by small fringe firms that have an on-site industrial process (e.g., forestry, pulp mill). Similar to the natural gas cogeneration facilities, these units bid a price of \$0/MWh in the majority of hours and infrequently bid high prices in excess of \$990/MWh. We assume that the small fringe producers of these units behave as price-takers and bid these assets at their marginal cost.

Finally, there are several hydroelectric facilities. These units are unique in that their marginal cost reflects the opportunity cost of the energy they could reallocate to another time period. Hydro units often bid their supply either at \$0/MWh or high prices often in excess of \$900/MWh. These high bids could reflect additional regulatory and ecological constraints. We set the marginal cost of these units to equal their bids. We anticipate the possible biases from this approach to be small in

[33]For additional details on the marginal cost estimation and data sources, see Appendix A.

[34]Discussions with regulators indicates that facility operators use these units to meet on-site needs and electricity sales are viewed as a byproduct. High-priced offers have been noted to reflect a situation where the operator does not use the unit for on-site needs, but must comply with regulations to physically offer the unit in the market.

our setting because hydro is a small proportion of the market. For example, in 2020 hydro output represented 2.5% of total electricity generation (AUC, 2020). Further, the non-zero bids are rarely called upon to supply electricity (approximately 95% of hydro output arises from zero-priced bids) and hydro units set the market-clearing price in only 1.6% of hours during our sample period.

In addition to computing marginal cost, we account for the presence of unit outages that impact a generator's capability to produce. These outages can occur randomly due to "forced outages" reflecting anticipated or unanticipated equipment maintenance. Using actual outages could bias unit availability in the competitive counterfactual because availability can be endogenously determined by strategic firms (Wolak and Patrick, 2001; Benatia and Villemeur, 2021).

We follow the approach employed by Borenstein et al. (2002) and Mansur (2007) and simulate unit availability of fossil-fuel units using a Monte Carlo simulation approach. Define η_{it} to be a random variable, FOF_i to be the forced outage factor reflecting the historical probability that unit i is on an outage, and K_i to be unit i's capacity. The output supplied in the competitive counterfactual for unit i in hour t equals:

$$q_{it}(P_t^*) \;=\; \begin{cases} K_i \quad \text{if} \quad P_t^* \geq c_{it} \text{ and } \eta_{it} \;>\; FOF_i \\ 0 \qquad\qquad\qquad\qquad\qquad\quad \text{otherwise,} \end{cases}$$

where P_t^* is the market-clearing competitive wholesale price and c_{it} is unit i's marginal cost. It is important to note that we treat longer-term outages lasting 7 days or more as being exogeneously determined.

For each hour and generation unit, we draw η_{it} from a uniform distribution on the support $[0, 1]$ to determine available output. This determines the set of available units.[35] The available output is stacked in order of least-cost to form an aggregate supply curve that is then intersected with residual demand which determines the competitive counterfactual price. If the residual demand exceeds available supply, we set the perfectly competitive price equal to the price-cap of \$999.99/MWh. We repeat this process 500 times yielding a distribution of prices for each hour. We calculated the average of these iterations to determine the competitive equilibrium price and quantity.

4.3 Net Import Supply Function

The decision to import electricity into Alberta is based on expected wholesale market outcomes in Alberta and conditions in neighboring jurisdictions. We follow the approach employed in Mansur (2007), Bushnell et al. (2008), and Brown and Olmstead (2017) and empirically estimate a price-responsive net import supply function. Alberta is a net importer of electricity in 78% of hours during our sample period, with the majority of imports coming from British Columbia.

[35] An alternative approach would be to "derate" available capacity of each unit by a forced outage factor (i.e., $q_{it} = K_i \cdot FOF_i$ if $P_t^* \geq c_{it}$ and zero otherwise). This would yield a measure of expected supply of output for any given level of demand. However, because the market-level cost function is convex, the actual expected cost of any given level of output will exceed the cost of expected supply (Borenstien et al., 2002).

For each year, we estimate the following net import supply function at the hourly-level t using the following linear-log specification:[36]

$$Q_t^{IM} \;=\; \beta_0 + \beta_1\, ln(P_t^{AB}) + \beta_2\, ln(P_t^{MidC}) + \gamma\, f(\text{Temp}_t) + \delta\, \mathbf{X}_t + \varepsilon_t \tag{3}$$

where Q_t^{IM} reflects the net imports from neighboring jurisdictions British Columbia, Montana, and Saskatchewan. P_t^{AB} and P_t^{MidC} represent the hourly Alberta wholesale price and the daily quantity-weighted average Mid-Columbia (Mid-C) peak price.[37] We include the Mid-C price to control for the fact that generators in British Columbia have the choice to export both to Alberta and the Pacific Northwest. $f(\text{Temp}_t)$ is an array of temperature variables from neighboring jurisdictions and $\mathbf{X}_t$ is a set of calendar controls for hour, each day of the week, month, and holiday. The calendar controls are included to capture systematic demand variation and input supply shocks. The temperature variables aim to control for variation in market conditions in bordering jurisdictions.[38] We estimate the net import supply regression at the yearly level to allow for changes in the relationship between net imports and the covariates over time. ε_t is the error term that is Newey-West heteroskedastic and autocorrelation robust with 24 hour lags.

The wholesale price in Alberta and the Mid-C price are endogenous to the level of net imports into Alberta. Consistent with the prior literature cited above, we use an instrumental variables (IV) approach to address this endogeneity. As instruments, we use the natural log of hourly Alberta wholesale demand and average daily demand at the Bonneville Power Administration (BPA) Balancing Authority, the largest Balancing Authority in the Northwestern United States. Demand in Alberta and the BPA are valid instruments because both only impact import and export decisions through the way they impact realized market prices in Alberta and Mid-C. Unlike many industries, electricity demand is highly price-inelastic in the short-run. This removes the direct linkage between net imports and wholesale demand via the impact that net imports have on market prices.

For each hour, we use (3) to establish a net import supply function. More specifically, we formulate residual demand facing suppliers in Alberta as the observed perfectly price-inelastic demand minus the estimated net imports for any given price-level. In our estimation of net imports, we take into account the physical constraints of the transmission network. In particular, we truncate our estimated net import supply above and below by the available transmission import and export capacity limits. This results in a downward sloping residual demand function at low to moderate prices that becomes perfectly price-inelastic at sufficiently high prices once the import supply constraints are binding. We use this hourly residual demand function to estimate the

[36] The linear-log specification controls for the rightward-skewed nature of wholesale prices.

[37] Mid-C is the major wholesale electricity trading hub in the Pacific Northwest (PNW) of the United States. The Mid-C daily quantity-weighted peak product prices will serve as a proxy for the economic value of exporting power from British Columbia to the PNW, possibly instead of supplying power to Alberta.

[38] The hourly temperature variables are modeled as quadratic heating and cooling degrees (relative to 65° F (18.33°C)). The cities considered are Vancouver, Saskatoon, and Billings, the largest cities in each jurisdiction.

market outcomes using the observed behaviour and the competitive supply curve (recall Figure 4).

The IV regression results are reported in Table A1 in the Appendix. As expected, in the first-stage regressions, Alberta and BPA demand have a positive impact on their respective wholesale prices. Further, we report several statistics that demonstrates that these covariates are strong instruments.[39] The estimated Alberta year-specific price coefficients are all positive and statistically significant, with the exception of the year 2017 which lacks statistical significance. 2017 had considerably lower Alberta wholesale prices and import supply. The implied price-elasticity of residual demand ranges from -0.01 to -0.08 when evaluated at the average year-specific residual demand levels. This low price-elasticity arises because of the relatively small size of imports in Alberta. Our estimated price-elasticity of residual demand falls in line with estimates for the PJM and New England regions of the United States found in Bushnell et al. (2008).

5 Results

We begin by providing the market-level results in Section 5.1 to demonstrate how the degree of market power varies over our sample. In Section 5.2, we present firm-level results to investigate how the allocation of the PPAs affected firms' abilities to impact market outcomes, as well as evaluate how several key firms adjusted their bidding behaviour after receiving the PPA units.

5.1 Market-Level Results

Table 2 reports average observed and competitive counterfactual prices, the average price markup, and our market performance measure in (1) for peak hours by year. The results demonstrate that our sample period begins with a high level of market power with an average markup of \$74.38/MWh in 2013, the highest level observed over our sample period. In 2014 and 2015, market power execution persists, but is lower than the high level observed in 2013. As will be discussed in detail below, this is driven in part by the entry of a large base-load natural gas unit (860 MWs) offered by a vertically integrated firm (ENMAX). The PPA units were offered into the market by large strategic buyers until 2016 when the PPAs were terminated, as discussed in Section 2. The interim period in which the PPAs were transitioned (i.e., in 2016), and the years 2017 - 2020 when the PPAs were offered by the Balancing Pool, had low to moderate levels of market power. The increase in market power between 2017 and 2018 coincides with the retirement of several coal units offered by the Balancing Pool, which as will be shown below corresponded with relatively tighter market conditions and higher market concentration.

Table 2 demonstrates that in 2021, when the PPAs expired and the assets reverted back to their original owners, we see a large increase in the degree of market power execution. In particular, the markup, reflecting the difference between the observed and competitive prices, increases by an

[39] Following Sanderson and Windeijer (2016), we report a number of statistics to evaluate the strength of our IVs, including the first-stage F-statistic, Sanderson and Windeijer's F-statistic, and the Kleibergen-Papp rk Lagrange-Multiplier test statistic for weak IVs. All measures are statistically significant at the 5% level providing consistent evidence that our IVs are not weak.

Table 2: Average Observed Price, Competitive Price, and Market Power Measures - Peak Hours (in 2021 CAD$s)

Year	Observed Price ($/MWh)	Competitive Price ($/MWh)	Markup ($/MWh)	Market Performance ($MP(\mathcal{T})$)
2013	125.49	51.10	74.38	0.59
2014	71.21	33.03	38.19	0.54
2015	45.63	24.81	20.82	0.47
2016	23.58	22.64	0.94	0.05
2017	36.26	30.05	6.21	0.19
2018	66.50	45.73	20.77	0.32
2019	72.31	48.17	24.15	0.34
2020	58.38	42.65	15.73	0.29
2021	128.67	68.87	59.80	0.47

Notes. Peak hours are defined by 6:00 AM - 10:00 PM. Competitive prices reflect the average of the Monte Carlo simulated competitive prices. $MP(\mathcal{T})$ is defined in (1). Markup is the difference between the observed and competitive prices. All $'s are inflation-adjusted to 2021 Canadian $s.

additional $44.07/MWh in 2021. This represents approximately two-thirds of the $70.29/MWh increase in average peak hour prices between 2020 and 2021. We find that increases in costs reflected in the higher competitive price in 2021 are driven by an increase in demand, natural gas prices, and carbon prices, account for the remaining one-third of the observed price increase. We decompose the various factors of cost and price increases between 2020 and 2021 in Appendix B.[40]

We find that the mean markups are systematically statistically significantly different from each other across years (see Appendix Table D2). In particular, the mean markups in 2013, 2014, and 2021 are statistically significantly higher than the markups over the period 2016 - 2020 when the PPAs were being transitioned to or offered by the Balancing Pool.[41]

Table 3 reports total payments and variable production costs under the observed and competitive counterfactual, and presents excess producer surplus (PS) and the change in variable cost under the observed outcome compared to the competitive benchmark for peak hours by year. Consistent with the results in Table 2, the excess PS and change in variable production costs are highest in 2013, 2014, and 2021 when market power execution reaches its peak. In each of these years, the PPAs were offered by large generation firms. Alternatively, the excess PS and change in costs are distinctly lower in 2016 - 2020 when the PPAs were being transitioned to or were offered by

[40] Appendix Table D3 reports the prices and market power measures for off-peak hours. The same markup pattern emerges (i.e., market power is higher when the Balancing Pool did not have offer control over the PPAs), but the degree of market power execution is considerably lower reflecting the more competitive environment.

[41] The one exception is in 2015 where the mean markups are not statistically significantly different from those in 2018 and 2019. This coincides with a period of low demand and entry of a large combined cycle gas plant. We will show that firms had reduced incentive and ability to exercise market power over this period in Appendix E.

Table 3: Payments, Variable Costs, and Producer Surplus - Peak Hours (in Millions 2021 CAD$s)

Year	Observed		Competitive			
	Payments	Costs	Payments	Costs	Δ Cost	Excess PS
2013	5,979	720	2,451	563	157	3,370
2014	3,647	729	1,676	621	108	1,866
2015	2,593	704	1,375	643	61	1,157
2016	1,356	638	1,292	623	14	49
2017	2,178	786	1,770	778	8	397
2018	4,053	1,047	2,750	992	55	1,248
2019	4,417	1,043	2,910	976	68	1,435
2020	3,579	910	2,532	845	65	982
2021	8,095	1,336	4,280	1,168	168	3,645

Notes. Peak hours are defined as 6:00 AM - 10:00 PM. Payments reflect the observed (or competitive) price multiplied by market demand. Variable production costs reflect the costs of generation from units in Alberta and net imports. Δ Cost represents the difference between the observed and competitive variable production costs. Producer Surplus (PS) is the difference between Payments and Production Costs. Excess PS reflects the difference between the Observed and Competitive PS. All $'s are inflation-adjusted to 2021 Canadian $s.

the Balancing Pool, particularly in relation to 2013, 2014, and 2021. These results demonstrate that the elevated market power execution is associated with a significant transfer of surplus from consumers to producers and elevated deadweight losses in the form of productive inefficiencies.[42]

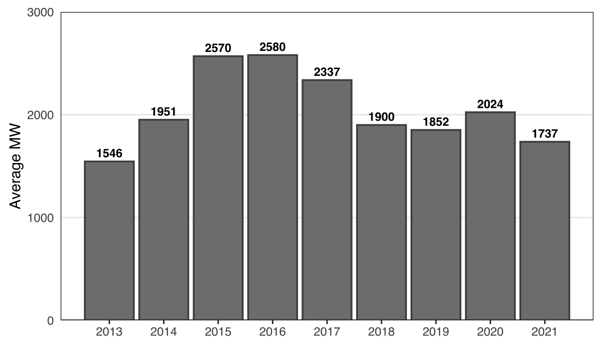
These results show that at the market-level, there was a considerable departure from the competitive benchmark in several years of our sample. This departure coincides with the offer control of the PPA assets being primarily allocated to the large oligopolists. We will now turn our attention to investigating the market-level conditions that are conducive to the execution of market power. To do so, we look to the realized supply cushion that represents the total available generation capacity in any given hour less market demand.

Figure 5 plots the annual average supply cushion and the ratio of the average supply cushion and average demand in peak hours by year. Several features are notable in this figure. First, the supply cushion in 2015 - 2017 is well above the rest of the period. In these years, the average peak

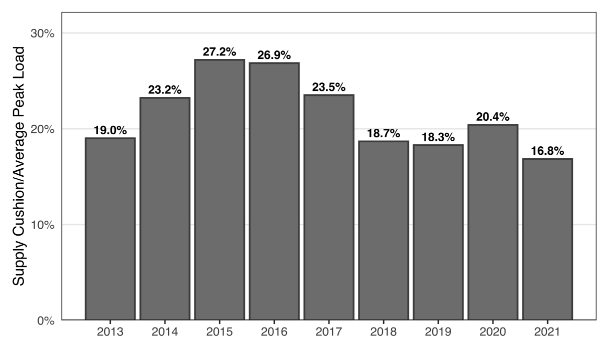
[42] The change in variable production costs are particularly pronounced in 2013 compared to the competitive variable costs. This arises for two reasons. First, as discussed in Brown and Eckert (2022), in 2013 we observe several firms economic withholding output from a sizable portion of their low cost coal units. This output is displaced by high cost gas units in peak hours. Second, there is a large amount of supply (28% of market output on average) from natural gas cogeneration. As discussed in Section 4.2, the output from these facilities is a byproduct of an on-site production process. We treat this output, which is systematically bid at $0/MWh, as having zero marginal cost. While this represents the opportunity cost of this supply and the output remains under both the observed and competitive outcomes, it reduces the absolute level of variable costs in the market. Consequently, in 2013 when thermal unit costs are relatively low, cost increases resulting from inefficient substitution of coal to gas can result in large percentage changes in variable cost.

supply cushion ranges from 24% to 27% of average peak demand. The higher supply cushion in these years is driven in large part by the entry of a large base-load natural gas unit that began to enter the market in 2014 and was fully online in 2015. This coincides with the lower degree of market power observed in these years relative to 2013. Second, the average supply cushion is lowest in 2013 and 2021, the years in which we observe the highest degree of market power. Consequently, the periods in which the large firms had offer control over the PPA units overlapped with the periods in which firms' abilities to exercise market power were closely aligned.

Figure 5: Supply Cushion Characteristics by Year (Peak Hours)



(a) Average Supply Cushion



(b) Ratio of Average Supply Cushion to Demand

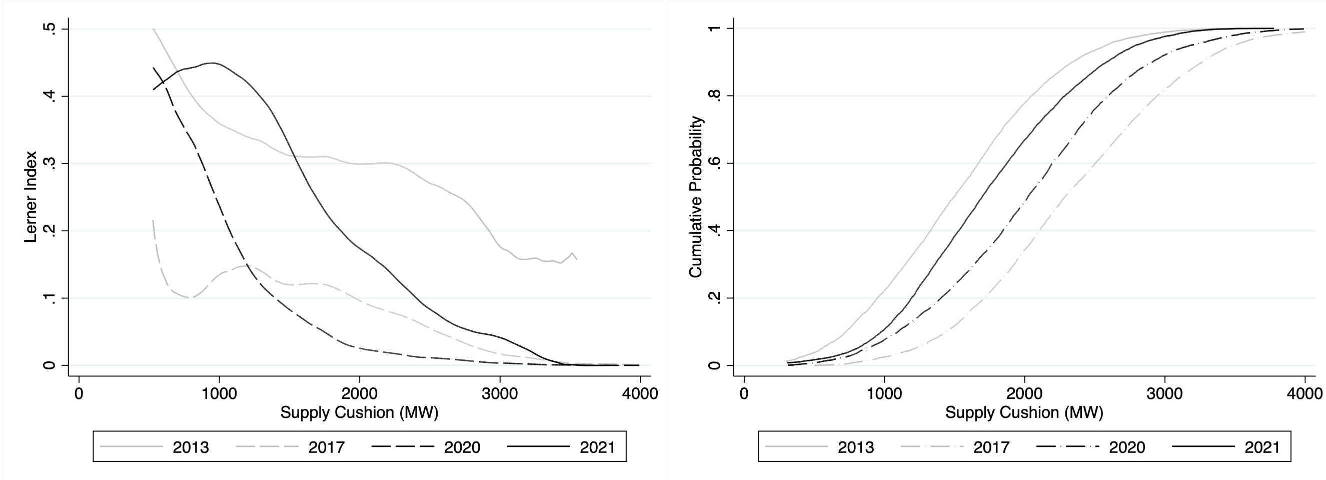
While our results above suggest that market power changed in 2016-2017 when the PPAs were transitioned to the Balancing Pool and then in 2021 when the PPAs transferred back to the original owners, the fact that other market conditions were changing makes it difficult to disentangle the various factors. For example, as shown in Figure 5, the degree of "tightness" in the market varies over time. We use the methods detailed in Section 4.1 that break down the degree of market power execution by the expected supply cushion measure to control for changes in market conditions.

Figure 6a presents the results of the kernel regression of the Lerner Index on the expected supply cushion for the years 2013, 2017, 2020, and 2021. We consider 2013 and 2021 because market power was elevated in these years and the PPAs were primarily controlled by the oligopolists, either the large PPA buyers or original owners (recall Figure 2). In 2017, the period of the transition of the PPAs to the Balancing Pool was completed and the PPAs were primarily offered by the Balancing Pool. Finally, 2020 provides a valuable comparison to 2021 as the PPAs expired and were reverted back from the Balancing Pool to their original (large) owners on January 1, 2021.

Figure 6a demonstrates that for the years 2013 and 2021, the Lerner Index systematically lies above the levels observed in 2017 and 2020.[43] In particular, even at relatively high supply cushion

[43]In 2021, the reduced Lerner Index in the tightest supply cushion hours is driven in large part by the fact that the last unit(s) dispatched are high-cost cogeneration facilities. Recall from Section 4.2, we take the bids of cogeneration units to be reflective of their marginal cost because the primary use of these facilities is to meet the demand from an on-site production process (e.g., oil sands). In the tightest supply cushion hours, a subset of the final bids that are accepted are the high-priced bids of these facilities reducing the Lerner Index measure to zero. These units are infrequently dispatched in the other reported years.

Figure 6: Expected Supply Cushion and Lerner Index in 2013, 2017, 2020, and 2021



(a) Lerner Index by Supply Cushion

(b) Supply Cushion Cumulative Distributions

values (e.g., 2,000 MWs), market power is higher in 2013 and 2021.[44] These results suggest that for a given level of market "tightness", there is a difference in market outcomes when the Balancing Pool had offer control over a sizable portion of the market's supply.

It is important to couple the results in Figure 6a with the distribution of the expected supply cushion by year to understand the incidence of these supply cushion levels. Figure 6b demonstrates that the expected supply cushion was tightest in 2013 and 2021, followed by 2020 and then 2017. The likelihood that the supply cushion lies between 800 MWs and 3,000 MWs, when the Lerner Index is higher in 2013 and 2021, is 86%, 81%, 89%, and 93% in 2013, 2017, 2020, and 2021.[45] These statistics highlight the fact that the degree of market power was distinctly higher in 2013 and 2021 in moderate-to-high supply cushion hours that cover the majority of hours in our sample.

We employ the reduced-form regression detailed in (2) to complement the results in Figure 6. Figure 7 presents the coefficients and the 95th percentile confidence intervals of the covariates in (2) by year and supply cushion quartile. Theses results provide a number of interesting insights.

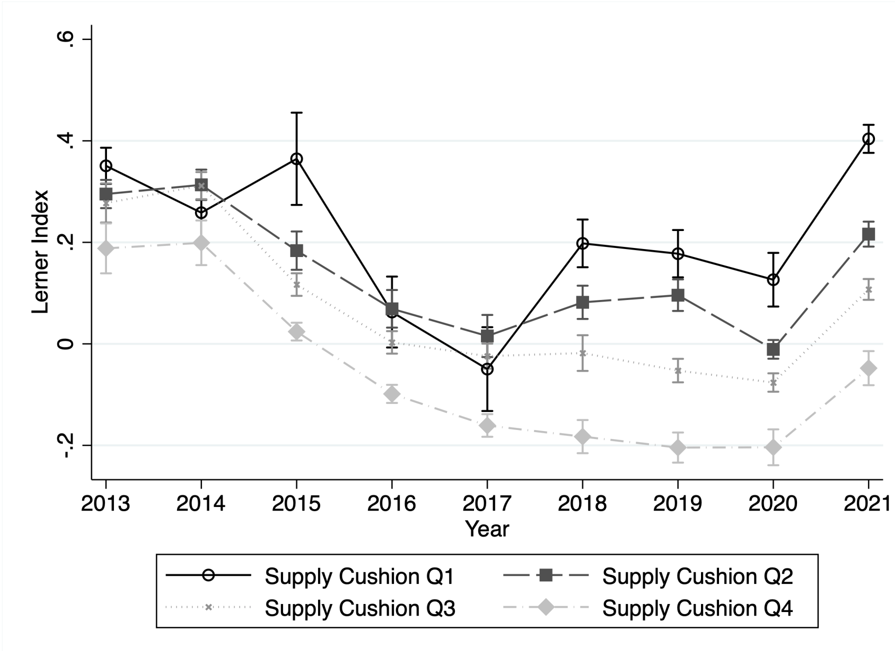
First, as expected, the degree of market power is typically higher in lower supply cushion quartiles.[46] This reflects hours where firms' abilities to exercise market power is highest. Second, in the years 2013 - 2015 and 2021, we observe a systematically higher estimated Lerner Index in the bottom 50th percentile of the expected supply cushion compared to the years 2016 - 2020. For the bottom two quartiles of the expected supply cushion, we evaluate if the estimated coefficients

[44] Brown and Eckert (2022) present evidence suggesting that firms were utilizing unique offer patterns and bid disclosure information to coordinate on high prices in Alberta's wholesale market in certain hours in 2013. The elevated market power in Figure 6a at all levels of supply cushion in 2013, even compared to 2021, is consistent with the evidence of coordinated action.

[45] The relatively lower probability in 2017 is driven by the fact that the supply cushion exceeds 3,000 MWs in a relatively large number of hours (approximately 18%) in this year.

[46] The exceptions to this finding are in 2014, 2016, and 2017 in the bottom 50th percentile of the supply cushion. However, within each year, the estimates are not statistically significantly different from their neighboring quartile.

Figure 7: Lerner Index Regression Coefficients by Year and Supply Cushion Quartile



are statistically significantly different in the years 2013 - 2015 and 2021 compared to the years 2016 - 2020 (see Appendix Table D4). These tests demonstrate that the estimated degree of market power is statistically significantly higher during the non-Balancing Pool era, with the only exception being in the expected supply cushion Q1 in 2014 which is not statistically significant from the expected supply cushion Q1 in 2018. These results are consistent with a reduction in the degree of market power execution when the PPAs were transitioned to or offered by the Balancing Pool within a given expected supply cushion quartile. Third, we observe negative markups in the highest supply cushion hours.[47] These negative markups could arise for several reasons as discussed in Section 4.1, including measurement error in our cost estimates or the presence of dynamic costs. Importantly, our primary focus is on changes in the degree of market power over time.

We now turn our attention to analyzing the change in the estimated market power execution around the transition periods where the PPA assets where transitioned to and from the Balancing Pool. First, we consider the period 2015 - 2017, when most PPA units were transferred from the initial PPA buyers to the Balancing Pool. As noted in Section 2.2, although the PPA buyers announced over the period from December 2015 to May 2016 their intention to exit their PPA contracts, a legal challenge resulted in delays to the Balancing Pool accepting offer control of most of the affected units; all but two of the affected generation assets were transferred to the Balancing Pool over the period from June 2016 to January 2017.[48] During the transition period between the

[47]Negative markups have been found in low demand and high supply cushion hours in other studies (e.g., Borenstein et al. (2002) and Brown and Olmstead (2017)).

[48]The remaining two assets, accounting for approximately 19% of the PPA capacity being terminated, were accepted by the Balancing Pool in December 2017.

announcements of the PPA terminations and their acceptance by the Balancing Pool, these assets were offered into the wholesale market at or near marginal cost. Because of this, we compare market power in 2015 to market power in 2016 and 2017, when the PPA assets were either under the control of or being transitioned to the Balancing Pool.

Figure 8: Lerner Index by Expected Supply Cushion, Semi-Annually, January 2015 - June 2017

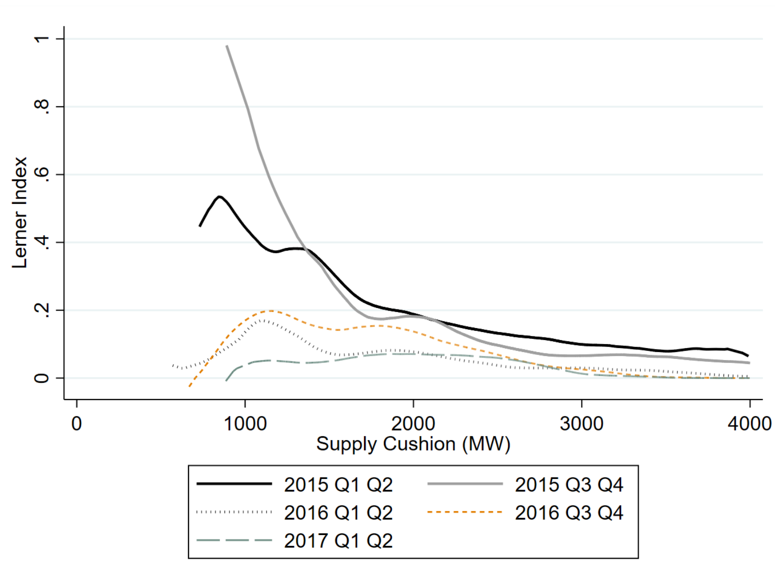


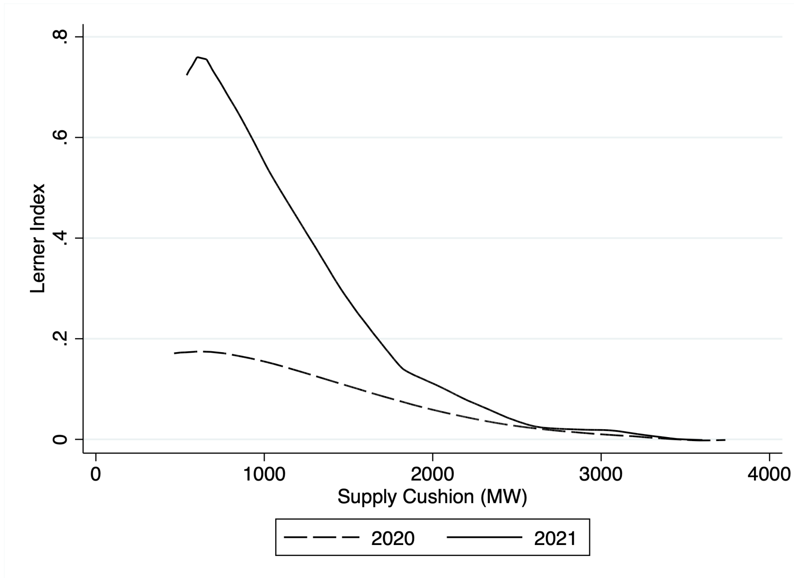
Figure 8 plots the estimated Lerner index against the expected supply cushion for each six-month period from January 2015 - June 2017. As can be seen in the Figure, controlling for the expected supply cushion, the degree of market power in 2015 exceeded the market power observed in 2016 and 2017 at all supply cushion levels. Hence, Figure 8 demonstrates that market power fell once the PPA buyers announced their intention to exit their contracts.

Second, consider the period around the expiry of the PPAs on January 1, 2021 where the portfolio of assets were unchanged, but a large portion of the market's capacity (15%) had its offer control transferred from the marginal cost-offering Balancing Pool to the strategic PPA owners essentially overnight. In particular, we focus on a narrow window ranging from November 4, 2020 to February 11, 2021. During this period, the configuration of assets competing in the market did not change.[49] Importantly, this implies that there is no inherent change in the operational capabilities of the generation assets in the market. This helps mitigate concerns that differences in the estimated market power are driven by changes in dynamic costs faced by generators (recall Section 4.1). Further, by focusing on a narrow window, this analysis helps control for changes in the expected supply cushion that can occur when comparing outcomes years apart.

Figure 9 presents the results of the kernel regression of the Lerner Index on the expected supply cushion by year for the time period November 4, 2020 - February 11, 2021. In the 2021 hours,

[49] A large coal-to-gas conversion was completed and online starting November 4, 2020. There were no large-scale outages or changes to the market portfolio running up to February 12, 2021 when another coal unit went on a long-term outage to be converted to natural gas.

Figure 9: Lerner Index by Expected Supply Cushion: November 4, 2020 - February 11, 2021



there is a considerably higher degree of market power execution for any given level of the expected supply cushion.[50] Reductions in the expected supply cushion correspond to greater market power. These results are consistent with a distinct change in market power execution when the PPAs expired and were transitioned to the large PPA owners. This re-enforces our findings that asset divestitures can have an important impact on market outcomes.[51]

5.2 Firm-Level Results

In this section, we consider whether and how changes in offer control over the PPAs affected the ability of the large generators to exercise market power. In addition, we investigate how firms adjusted their offer behaviour over our sample period and whether changes in behaviour coincide with the changes in the allocation of the PPAs.

5.2.1 Pivotal Supplier and Inverse Semi-Elasticity Measures

We estimate metrics to quantify firms' abilities to exercise market power. We begin by calculating the residual supplier index (RSI) for each of the 5 largest strategic firms (TransAlta, Capital Power, ATCO/Heartland, ENMAX, and TransCanada), plus the Balancing Pool.[52] The

[50] We investigate if there were significant changes in underlying market conditions during the 2020 - 2021 window period. We find that there was a period of elevated demand and natural gas prices corresponding with a period of sustained cold weather. We find that the results in Figure 9 remain even after we remove this period in 2021.

[51] Using data from 2020 - 2021, we carried out a number of regression analyses that regressed the Lerner Index on key market variables including hourly wind output, demand, import capacity limits, and fixed-effects for each month, day-of-week, and hour of day. We continue to find statistically significant elevated market power in 2021 relative to 2020, controlling for these factors. Detailed results are available upon request.

[52] Capital Power was spun off from EPCOR Utilities in 2008 as the generation entity. Heartland Generation purchased the majority of the assets of ATCO Utilities in 2019. ATCO continues to have offer control of a small (32 MW) hydro facility. For simplicity, we denote the firm as ATCO/Heartland, which represents ATCO prior to the selling of the assets and Heartland thereafter.

RSI, a common metric employed to monitor wholesale market concentration, measures the degree to which a firm is deemed *pivotal* in that a portion of its supply is needed to clear the market. The RSI of firm j for hour t is given by the following formula, where a value below 1 indicates a firm is deemed pivotal:

$$RSI_{j,t} = \frac{\textit{Total Supply}_t - \textit{Available Supply Controlled by Firm } j_t}{\textit{Total Demand}_t}. \tag{4}$$

Figure 10 plots the percentage of hours each firm is deemed pivotal (the share of hours their hourly $RSI_{j,t} < 1$), by year. Prior to the transfer of the PPAs in 2016 - 2017, the majority of the PPAs were held by TransCanada, ENMAX, and Capital Power, with 42%, 29%, and 14% of PPA capacity, respectively. In 2013 and 2014, TransCanada, who was the largest firm (with offer control of over 18% of Alberta generating capacity), was a pivotal supplier in nearly 75% of hours. Since over 80% of TransCanada's capacity (in terms of offer control) derived from its PPAs in these years, its substantial ability to exercise market power in this period can be directly attributed to the PPAs. In addition, in 2013, during which the highest average markup in our sample is observed, TransCanada's pivotal status coincided with a considerable share of hours deemed pivotal for the other large PPA holders ENMAX and Capital Power.

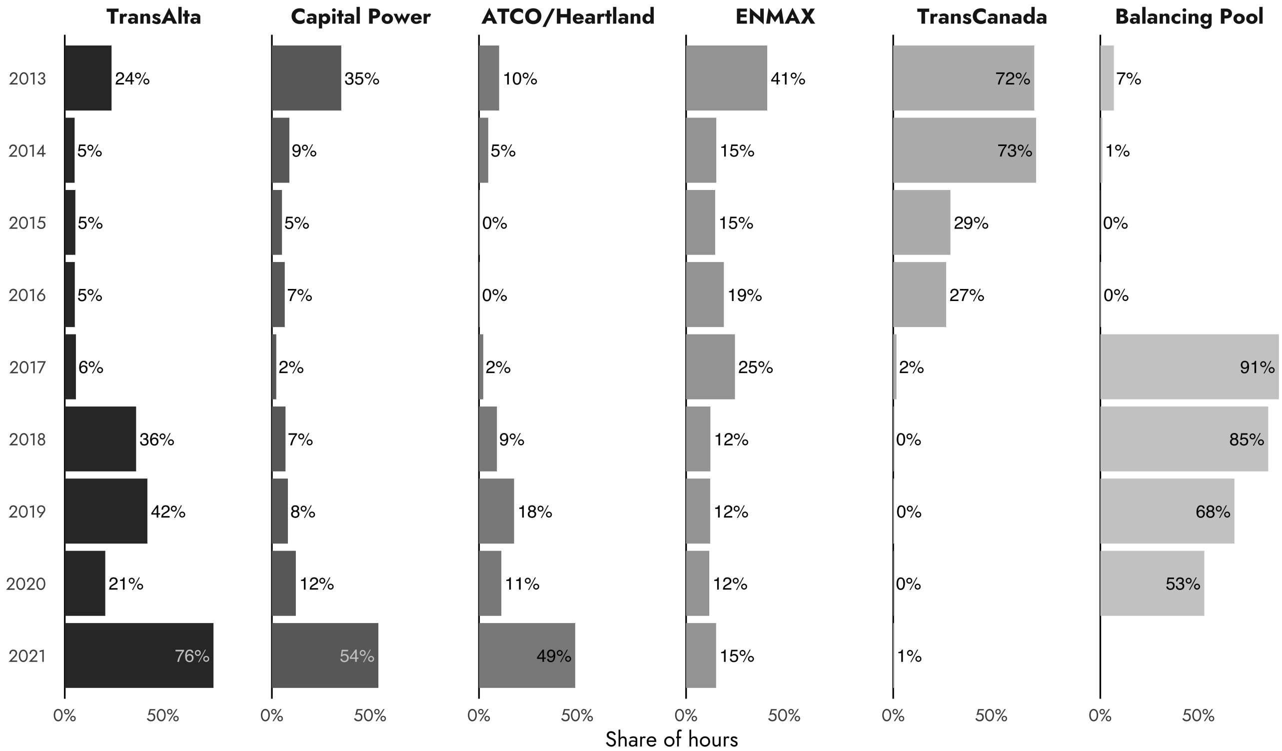
With the completed transfer of the PPA units from TransCanada (and others) to the Balancing Pool in 2017, we see a substantial increase in the Balancing Pool's pivotal supplier status, which in 2017 was pivotal in over 90% of hours. The large strategic firms were rarely pivotal in 2017, with the exception of ENMAX. It is important to emphasize that ENMAX has a unique position because it is a vertically integrated producer with a sizable retail commitment.[53] It has been shown that such vertical arrangements can lead firms to behave more competitively (Bushnell et al., 2008). The ability of large strategic firms, and particularly TransAlta, to exercise market power started increasing in 2018 as certain PPAs expired and offer control was returned to the owners of the assets. The pivotal supplier status of the Balancing Pool declined over this period.

The expiry of the remaining PPAs at the end of 2020 and the return of offer control to the owners TransAlta, Capital Power, and Heartland had a dramatic effect on their ability to exercise market power, with TransAlta becoming pivotal in 76% percent of hours, followed by Capital Power with 54% and Heartland with 49%. This increase coincided with the large increase in market power observed in 2021.

While the RSI captures the extent to which a firm's capacity is needed to serve the market, which is associated with its ability to exercise market power, more generally the ability of a firm to exercise market power depends on the offer behaviour of rivals. To address this, we also employ a method developed by Wolak (2000, 2003) that relies on a model of unilateral profit-maximization

[53] With the exception of ATCO, the remaining generators are not vertically integrated. ATCO established a retail-arm in 2016, but sold the majority of its generation assets in 2019 to Heartland which has no retail commitments.

Figure 10: Annual Frequency of Firms Deemed Pivotal Based on the RSI Metric

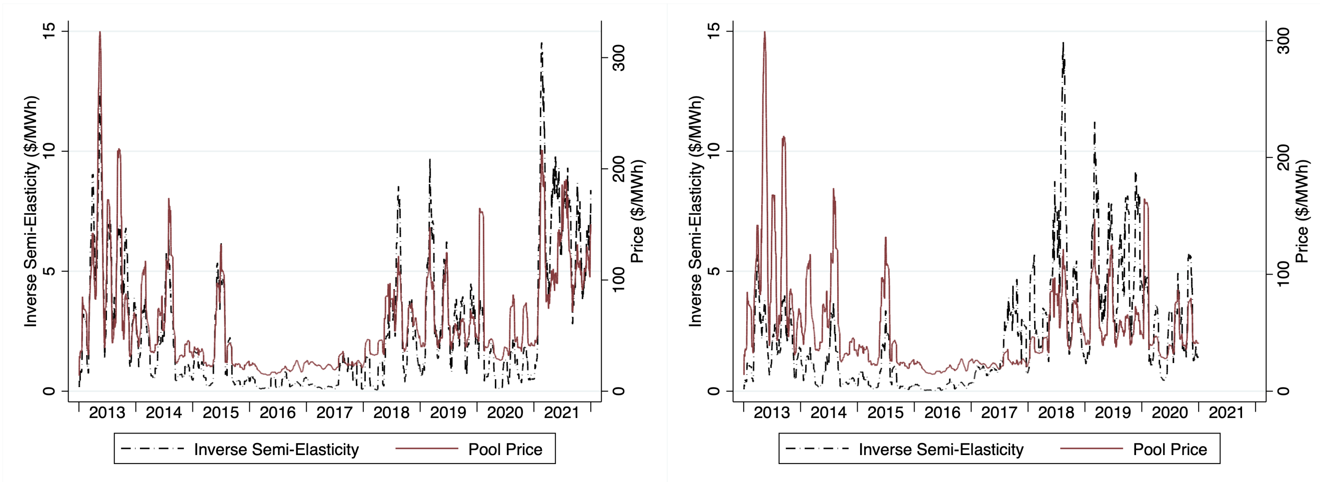


Notes: Each bar represents the share of peak hours (6:00 AM - 10:00 PM) in a given year that a firm is deemed pivotal, i.e. their RSI as calculated in (4) is less than 1.

and demonstrates that a generator's ability to exercise market power depends on the properties of the residual demand function it faces; residual demand in this context equals market demand minus its rivals' supply offers. This method directly considers how the shape of rivals' supply curves facilitates a strategic environment that is conducive of market power execution. This literature establishes a metric referred to as the inverse semi-elasticity of the residual demand curve in the region of the equilibrium. The inverse semi-elasticity measure captures the \$/MWh change in the market-clearing price that would result from a 1% reduction in the supplier's output. A higher value is associated with an elevated ability to exercise market power. For brevity, we will present the average inverse semi-elasticity of the large Oligopolists and the Balancing Pool. Appendix E provides a detailed summary of the approach and firm-level results.

Figure 11a demonstrates that the inverse semi-elasticity measure for the Oligopolists is pronounced in the early years of our sample and in 2021 after the expiry of the PPAs. Alternatively, when the PPAs were transitioning to or offered by the Balancing Pool, the ability to exercise market power was reduced. This is most apparent in 2016 and 2017 before certain PPA units were retired in 2018 which led to a tightening of the market. The reduced inverse semi-elasticity over this period is likely driven in part by the fact that the PPA assets were bid in at low prices leading

Figure 11: Inverse Semi-Elasticity Measure and Pool Prices - Oligopolists and Balancing Pool



(a) Oligopolists

(b) Balancing Pool

Notes. The reported Oligopolists results reflect the average inverse semi-elasticity of the large strategic firms in each hour. The plots represent 30-day moving averages of the hourly inverse semi-elasticity measure.

to a flattened residual demand curve. Figure 11a also illustrates that there is a strong positive correlation between the inverse semi-elasticity measure of the Oligopolists and the market-clearing pool price (i.e., $\rho = 0.89$). These results show that the periods where market conditions were relatively tight (e.g., as show via the supply cushion above) and the PPA units were offered by large firms, the Oligopolists had considerable ability to exercise unilateral market power.[54]

Figure 11b demonstrates that the Balancing Pool had an elevated ability to exercise market power over the period 2017 - 2020 when it acquired the PPA assets. Despite the Balancing Pool's ability to exercise market power over this period, we will demonstrate below that it bid in a manner that would be consistent with a price-taker. Further, the correlation between the inverse semi-elasticity measure of the Balancing Pool and the market-clearing pool price is considerably lower than that of the Oligopolists with a correlation coefficient of $\rho = 0.47$.

5.2.2 Bidding Behaviour

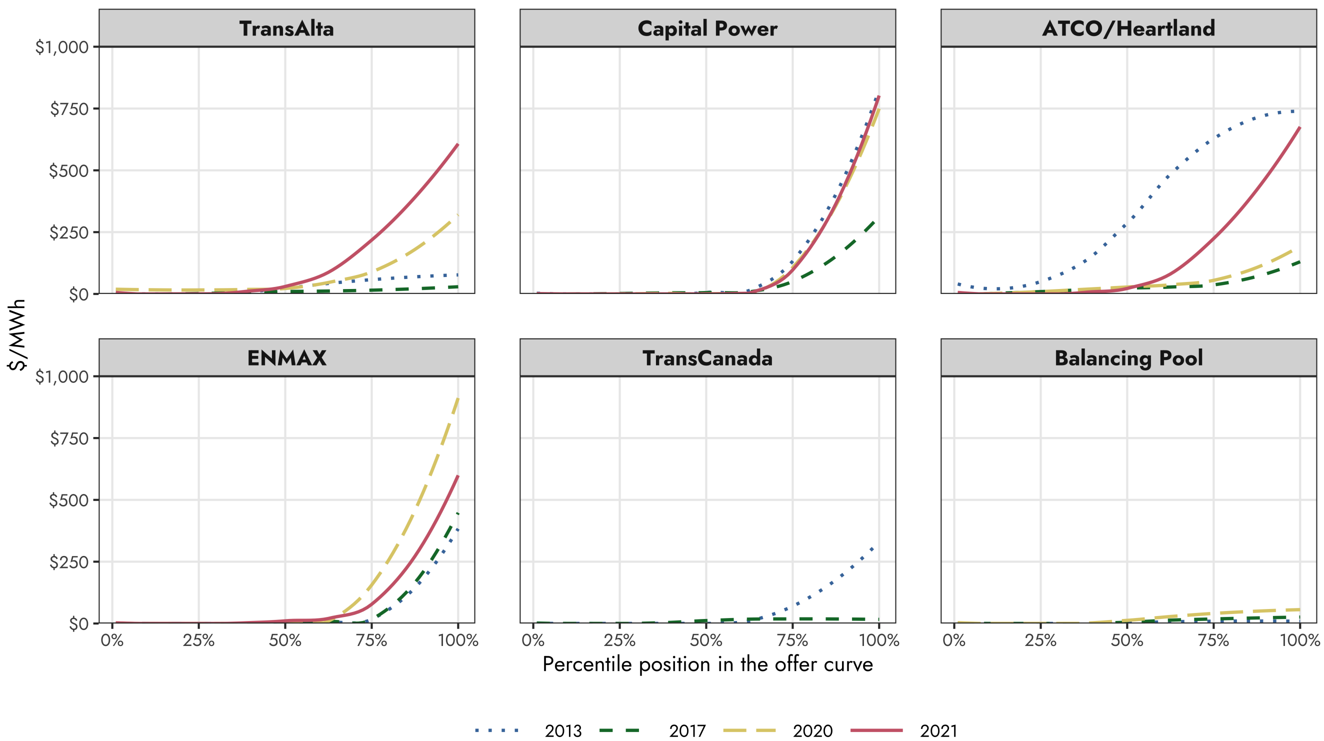
The previous subsection demonstrated that there is a key relationship between the allocation of the PPAs and firms' abilities to exercise market power. In this subsection, we will use firm-level bidding data to evaluate if the changes in the PPAs and firms' abilities to exercise market power are associated with observed adjustments in bidding behaviour.

Figure 12 plots the average offer curves for each of the large firms, plus the Balancing Pool, for four years: 2013, 2017, 2020, and 2021. As noted above, 2013 and 2021 represent years in which,

[54] It is well-known that the ability to exercise market power can differ from the incentive due to the presence of forward contracts (Bushnell et al., 2008; McRae and Wolak, 2014). We use the method outlined in McRae and Wolak (2014) to adjust the inverse semi-elasticity measure to account for forward commitments. While this reduces the size of the inverse semi-elasticity measure, the same patterns persist. See Appendix E for details.

because of the allocation of PPA capacity, large strategic firms had a high ability to exercise market power, while in 2017 and 2020 the entity most frequently pivotal was the Balancing Pool. The offer curves are constructed by calculating the offer price for each percentile of each firm's hourly offer curve, and averaged to an annual value by percentile. The offer curves indicate the average percentage of the firm's capacity being offered at or below different prices. We restrict this analysis to thermal power plants, excluding cogeneration. These are deemed the most likely plants from which to economically withhold generation.

Figure 12: Cumulative Offer Curves, 2013, 2017, 2020, and 2021



Notes. We calculate the offer price for each block in each firm's cumulative offer curve in each hour, assigning the quantity to a percentile based on each hour's total offer quantity, and then average each percentile's offer value separately by year to get an annual-by-percentile value. The lines shown here use a LOESS smoothing algorithm through the individual percentile values. We include only coal, combined cycle natural gas, simple cycle natural gas, and dual fuel thermal offers, for peak hours only (6:00 AM - 10:00 PM), in this figure.

A large proportion (often at least 50%) of each firm's capacity was offered at prices at or near $0. These offers represent minimum stable generation or otherwise inflexible blocks for large thermal plants. Low-priced offers (e.g., below marginal cost) could also reflect firms' forward contract positions. For this output, firms have no incentive to economically withhold these quantities in an attempt to raise prices.[55]

[55]It has been shown in the empirical and theoretical literature that forward contracts can reduce firms' incentives to exercise market power (Wolak, 2000; Bushnell et al., 2008). Further, for quantities that lie below a firm's forward position, the firm has an incentive to bid this supply at or below its short-run marginal cost (Hortacsu and Puller, 2008).

Figure 12 demonstrates that the large firms typically submitted a portion of their offer curve at high prices in excess of $100/MWh.[56] In 2013, several large firms, including Capital Power and TransCanada, offered a sizable portion of their supply at high prices. Recall from Figure 10 that in 2013 the large firms most frequently pivotal were the three PPA buyers Capital Power, ENMAX, and TransCanada.[57] Now, considering the transition of the PPA offer control to the Balancing Pool in 2016 - 2017. We observe a general reduction in offer prices in 2017. This is consistent with the reduced ability of these firms to exercise market power as shown in Section 5.2.1; the only firm that was pivotal with any frequency in 2017 was the Balancing Pool.

Turning next to the expiry of the PPAs at the end of 2020, Figure 10 demonstrated that this event substantially increased the ability of the three PPA owners (TransAlta, Capital Power, and Heartland) to exercise market power in 2021. Figure 12 demonstrates that TransAlta and Heartland both increased the proportion of their supply curve offered at high prices going from 2020 to 2021. Capital Power exhibited similar offers curves in 2020 and 2021; however, Capital Power's 2021 bidding strategy appears to have been split between two regimes: a high bidding strategy in the first four months, transitioning to flatter offer curves and less economic withholding from May onward (see Figure C2 in Appendix C). This could be driven by an increase in its forward hedged quantity, shifting its bidding strategy. Overall, Figure 12 suggests increased offer prices by at least two of the three PPA owners after the expiry of the PPAs.

Figure 12 confirms the "variable cost offer strategy" of the Balancing Pool, with all capacity generally offered at low prices at or below marginal cost in all four years. This provides additional justification for interpreting 2017 as a year in which the PPA capacity was transferred from large strategic firms to a competitive fringe of price takers.

As an alternative approach to examining the firms' offer strategies, we calculate the percentage of available capacity for each firm in each year that is "economically withheld"; that is, the percentage of the firm's available capacity that is offered at a price above the system marginal price for the hour and therefore not dispatched, even though it has a marginal cost below this price.[58] As indicated earlier, since firms are required to offer all available capacity into the wholesale market, economic withholding is the avenue through which firms can exercise market power.

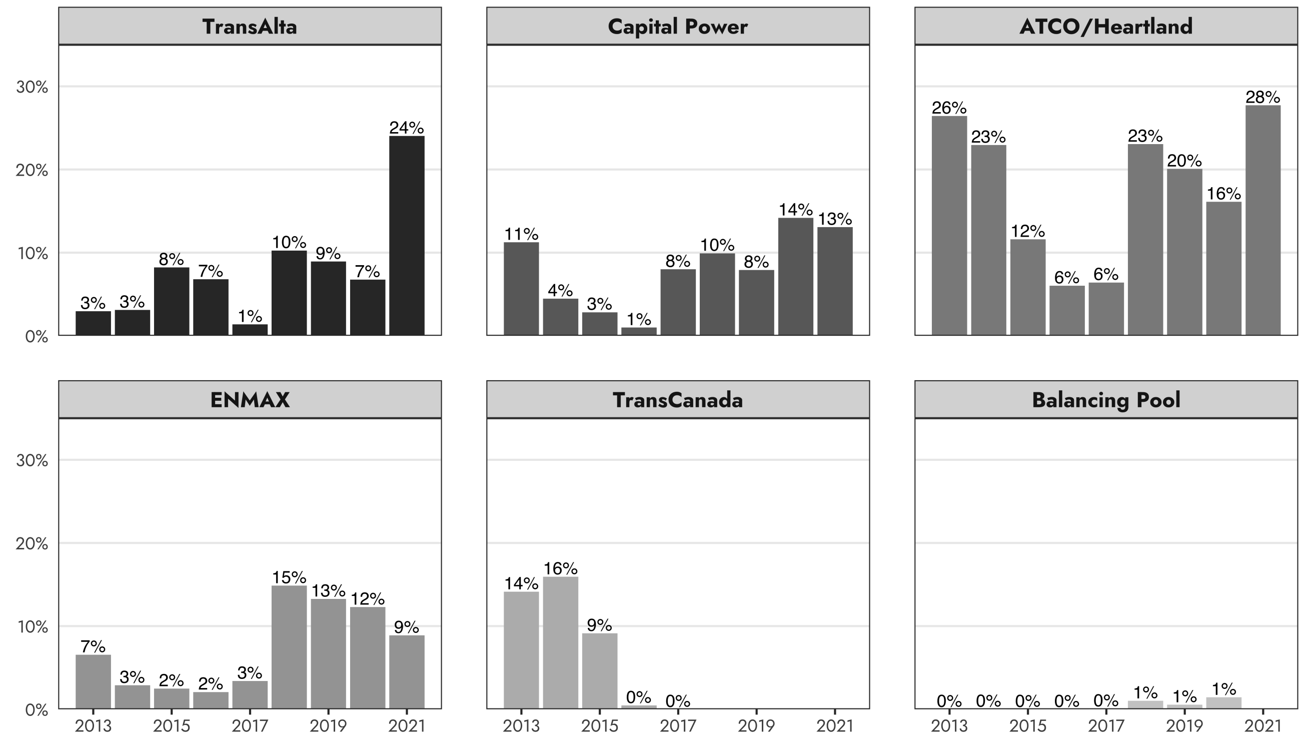
Figure 13 presents the share of offers economically withheld by firm and year. In 2013, TransCanada and Capital Power, both PPA buyers and firms that had considerable ability to

[56] Bids in excess of $100/MWh exceed the average short-run marginal cost of the large firms' thermal units which typically set the market-clearing price and range from $20.29/MWh to $40.59/MWh. In fact, Heartland has the highest marginal cost among the large firms and the 99th percentile of its marginal cost equals $72.51/MWh, demonstrating that even outlier marginal costs fall below $100/MWh.

[57] As noted above, ENMAX's incentives to exercise market power could be weaker because of its vertical arrangements. Figure 12 shows that ENMAX has a sizable proportion of its offer curve priced-out. Investigating these offers reveals that these bids reflect its peaker simply-cycle gas units. These high-priced offers could reflect ENMAX's preference to avoid incurring the associated dynamic costs of turning-on these units.

[58] In Figure 13 we require the offer price of an economically withheld block to exceed its marginal cost by at least $10/MWh to allow for measurement error in marginal cost. Our results are qualitatively similar with and without this buffer.

Figure 13: Share of Discretionary Offers Economically Withheld



Notes. An offer is deemed economically withheld when the marginal cost of that particular generator block is less than the market-clearing price, allowing for a \$10/MWh buffer on our estimate of marginal cost to allow for measurement error, but the offer price for the block is above the market clearing price. We include only coal, combined cycle natural gas, simple cycle natural gas, and dual fuel offers in peak hours (6:00 AM - 10:00 PM) in this figure.

exercise market power in this year, are observed to economically withhold over 10% of their MWhs. ATCO, not one of the PPA buyers, also withheld a sizable portion of its supply in the early years of our sample. The degree of economic withholding was low for most firms in 2017, increasing again in 2018 as coal units retire and certain PPAs are terminated.[59]

Considering next the expiry of the PPAs at the end of 2020, Figure 13 demonstrates a large increase in economic withholding in 2021 relative to 2020 for both TransAlta and Heartland. This corresponds with their increased frequency of being pivotal due in part to these firms receiving the expired PPA units. We observe no increase in the degree of economic withholding by Capital Power, consistent with Figure 12.[60]

Finally, the Balancing Pool rarely offered prices at levels that are deemed economic withholding. Appendix F provides a detailed discussion and analysis of the Balancing Pool's bidding behaviour

[59] Contrary to its behaviour earlier in the sample, ENMAX is observed to increase its percentage of MWhs that are economically withheld in 2018 - 2020. This behaviour reflects ENMAX often bidding up several of its simple-cycle gas units and is consistent with prices being too low for it to justify starting up these assets in certain hours.

[60] Again, see Appendix C for a discussion of Capital Power's offer behaviour throughout 2021. Capital Power's 2021 behaviour seemingly consisted of two regimes: withholding an average of 21% during the first four months of the year, falling to 9% on average over the remainder of the year (see Figure C1)

and the offers on the PPA units more broadly over our sample period. This analysis demonstrates that the PPA assets were used as part of the large strategic generators' economic withholding strategies in certain hours. Alternatively, these assets were systematically offered at or below marginal cost when they were offered by the Balancing Pool.

To summarize our firm-level analysis, we find that the transfer of the PPAs from large firms to the Balancing Pool, and then from the Balancing Pool to the original owners, had a substantial impact on the ability of the affected firms to exercise market power. Although the incentives of individual firms to exercise market power can depend upon their vertical integration status or forward market position, our discussion of the firm-level offer behaviour indicates higher offer prices and increased withholding in the years prior to the transfer of PPA offer control to the Balancing Pool in 2017, and an increase in offer prices and withholding by PPA owners in 2021 after the PPA expiry. These findings are consistent with observed changes in the degree of market power over our sample.

6 Conclusion

In this paper, we analyze the role of virtual asset divestitures on competition using the case of Alberta's wholesale electricity market. To address initial concerns of high concentration during market restructuring, Alberta initiated 20-year Purchase Power Arrangements (PPAs) that effectively leased out generation capacity from the original owners to other generation firms. We analyze market outcomes after these virtual divestitures expired at the end of 2020, transferring offer control back to the original large strategic owners increasing market concentration. Further, we exploit the fact that the PPA assets were transferred across heterogeneous firms to understand how the allocation of divested assets impacts market outcomes.

We quantify market power execution by developing a perfectly competitive benchmark. We demonstrate that Alberta experienced several years of moderate-to-high levels of market power execution in peak hours. We show that market power is elevated when the virtually divested assets were allocated to other large strategic oligopolists. Alternatively, when the assets were transferred to an entity that behaved as a competitive fringe producer, market power execution decreased considerably.

We find that the exercise of market power can explain two-thirds of the 120% increase in average peak hour prices between 2020 and 2021. The sizable increase in market power coincides with the expiry of the PPAs and resulted in a large transfer of payments from consumers to producers. We demonstrate that while market conditions varied throughout our sample period, the degree of market power execution was distinctly higher when the divested assets were offered into the market by large strategic generators, holding the degree of market "tightness" constant.

Our analysis demonstrates the important role that asset divestitures and their allocation to heterogeneous firms can have on market outcomes in wholesale electricity markets. Further, our analysis serves as a cautionary tale of what happens when market power mitigation policies are removed in a concentrated wholesale market. In particular, as a small market with limited interconnections to other grids, Alberta's market is likely to remain prone to periods of elevated market power for the foreseeable future. This suggests a possible role for other tools in antitrust and competition policy that serve as "conduct" remedies to reduce the prevalence of market power, such as bid mitigation policies (Graf et al., 2021) or a mandate for long-term contracting to reduce firms' incentive to exercise market power (Wolak, 2021).

It is important to acknowledge that our analysis focuses on short-run market outcomes and abstracts away from issues related to fixed costs, generator entry and exit, and the broader financial implications on the impacted firms. In particular, in restructured electricity markets there is a long-standing debate over the ability of generators to recover their fixed costs (Bushnell et al., 2017). It is possible that the elevated market power observed in Alberta's "energy-only" market in certain years is required to permit fixed cost recovery, particularly after several years of low prices when the PPA units were offered in at marginal cost. Further, it is possible that the allocation of the PPAs to the Balancing Pool could have impacted generator entry/exit decisions, as well as having other financial implications such as the cost of or access to credit. Despite abstracting away from these longer-term questions, our analysis provides insights into the short-run impacts of asset divestitures on market competition.

Our analysis develops a competitive counterfactual benchmark to describe changes in short-run market power execution over time. We employ various descriptive statistics and reduce-form regressions to demonstrate that the nature of market power changed over our sample period and explain how this coincides with the allocation of the virtually divested assets. Future research could use our setting to develop a structural model to consider additional counterfactual simulations to understand how alternative allocations of these assets could impact market outcomes, and possibly consider the implications of these allocations on longer-term entry and exit decisions.

Appendices

A Marginal Cost Details

Data for natural gas heat rates were obtained from the Alberta Market Surveillance Administrator, Alberta Utilities Commission, and AESO. CASA (2004) provides the heat rates for coal units in Alberta. We use data from the U.S. Energy Information Administration (EIA) to establish technology-specific O&M costs (EIA, 2013, 2016, 2020). Daily natural gas prices were obtained from the Alberta Natural Gas Exchange. We use weekly Powder River Basin (PRB) coal prices provided by the EIA to estimate the marginal cost of coal units.[61] The coal prices, natural gas prices, and variable O&M estimates were converted from US dollars to Canadian Dollars using Bank of Canada exchange rates.

Generators in Alberta are subject to environmental regulations. The carbon pricing policy has changed several times over our sample period resulting in more stringent environmental regulations. At the beginning of our sample, under the Specified Gas Emitters Regulation (SGER), generators that produced at least 100,000 tCO2e annually faced a carbon price of $15/tCO2e on emissions and were allocated credits to cover emission costs of 88% of a facility's historic emissions intensity. Effectively, a large generator pays a carbon price of $15/tCO2e on 12% of their emissions intensity. The policy become more stringent in 2016 (2017) as the benchmark decreased to 85% (80%) and the carbon price increased to $20/tCO2e ($30/tCO2e).

In January 2018, a new carbon pricing policy eventually named the Technology Innovation and Emissions Reduction Regulation (TIER) was implemented. Under TIER, facilities pay a carbon price of $30/tCO2e on the difference between their emissions intensity and the emissions intensity of an industry-wide benchmark set at 0.37 tCO2e/MWh. In January 2021, the carbon price increased to $40/tCO2e. For additional details on the policy and approach to computing the marginal cost of environmental compliance, see Brown et al. (2018).

During our sample period, there were a number of coal-to-gas unit conversions. We use conversion dates provided to us by the Alberta MSA to define when these conversions occurred and were completed. Prior to this date, we treat the units as coal. After this date, we estimate the marginal cost of these units using natural gas prices. As detailed in Section 4.2, we treat the timing of outages on these units to complete the coal-to-gas conversions as exogenous.

[61] Brown and Olmstead (2017) employ a Monte Carlo simulation approach that approximates the marginal cost of coal units using unit-specific bids in low demand hours. The authors find that their Monte Carlo simulated marginal costs are closely aligned with the estimates obtained using coal unit heat rates and PRB coal prices.

Table A1: Estimation of the Net Import Supply Function by Year

	2013			2014			2015		
Model	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}
$ln(P^{AB})$			357.1***			288.6***			323.6***
			(93.05)			(35.46)			(52.11)
$ln(P^{MidC})$			-212.9			-110.2			-2.358
			(214.5)			(93.45)			(96.57)
$ln(Q^{AB})$	3.625***	0.0413		6.426***	0.512**		3.896***	0.692**	
	(0.918)	(0.171)		(0.456)	(0.236)		(0.528)	(0.351)	
$ln(Q^{MidC})$	1.599***	1.278***		0.119	1.652***		-0.272	1.131***	
	(0.533)	(0.174)		(0.336)	(0.260)		(0.252)	(0.206)	
F-Stat	12.13***	28.15***		100.52***	24.71***		27.22***	18.53***	
S-W F-Stat	16.53***	31.40***		199.08***	41.58***		42.13***	30.58***	
K-P LM	16.68***			67.95***			30.32***		
	2016			**2017**			**2018**		
Model	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}
$ln(P^{AB})$			253.0**			82.56			382.3***
			(102.0)			(139.4)			(70.13)
$ln(P^{MidC})$			-638.2***			-400.8***			-423.7***
			(133.2)			(94.96)			(65.57)
$ln(Q^{AB})$	2.275***	0.355		2.806***	2.665***		4.177***	0.576	
	(0.220)	(0.218)		(0.452)	(0.555)		(0.491)	(0.521)	
$ln(Q^{MidC})$	-0.109	1.215***		0.223	1.865***		0.132	3.718***	
	(0.164)	(0.224)		(0.243)	(0.347)		(0.270)	(0.389)	
F-Stat	53.88***	14.70***		19.25***	22.28***		36.29***	47.55***	
S-W F-Stat	102.47***	32.23***		15.83***	14.43***		71.82***	94.95***	
K-P LM	35.68***			14.82***			54.42***		
	2019			**2020**			**2021**		
Model	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}	First $ln(p^{AB})$	First $ln(p^{MidC})$	Second Q^{IM}
$ln(P^{AB})$			439.5***			468.1**			746.6*
			(111.5)			(216.8)			(407.3)
$ln(P^{MidC})$			-312.4***			332.9*			386.5*
			(66.01)			(181.3)			(231.8)
$ln(Q^{AB})$	2.544***	1.962***		2.560***	-0.799		1.346**	0.452	
	(0.428)	(0.628)		(0.537)	(0.877)		(0.652)	(0.650)	
$ln(Q^{MidC})$	-0.856**	2.079***		-0.433	1.842***		-0.932**	1.738***	
	(0.354)	(0.339)		(0.315)	(0.416)		(0.380)	(0.501)	
F-Stat	20.40***	33.35***		12.12***	10.10***		4.21**	7.70***	
S-W F-Stat	40.72***	66.45***		14.44***	12.80***		4.22**	5.85**	
K-P LM	33.24***			8.91***			3.95**		

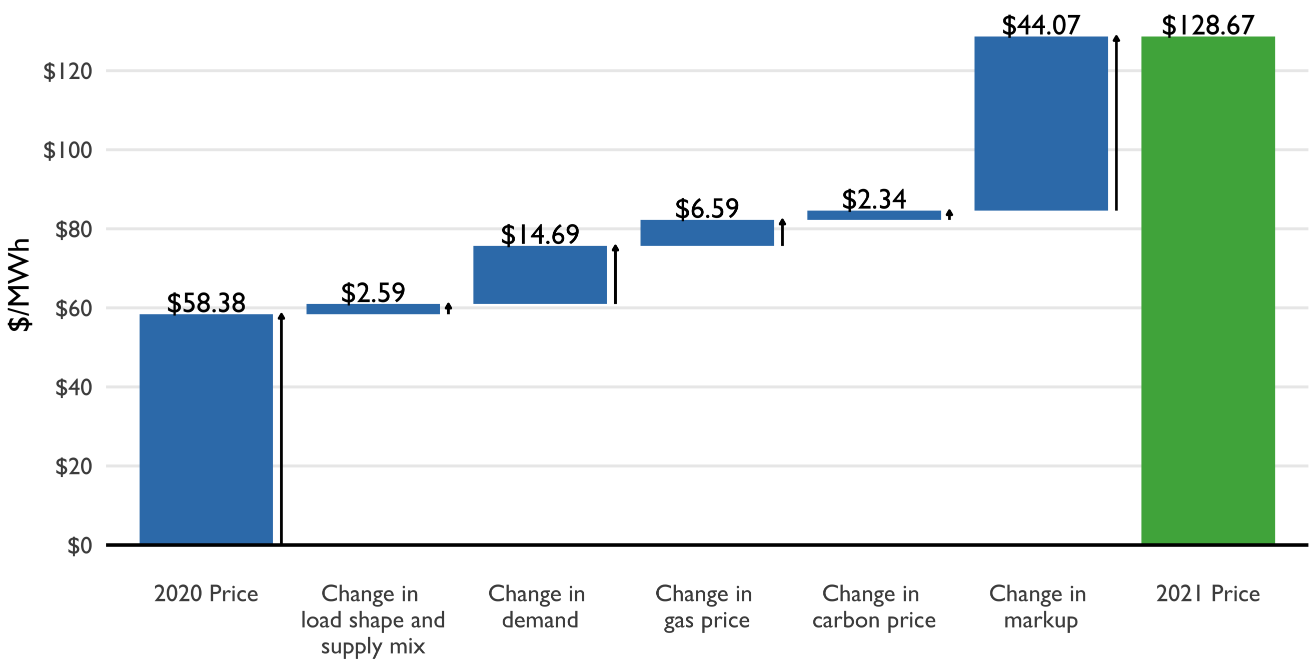
Notes. First reflects the first-stage IV regression estimates for the endogenous variables $ln(p^{AB})$ and $ln(p^{MidC})$. Second reflects the second-stage net import supply function in (3). Standard errors in parenthesis are heteroskedastic-robust with 24 lags to control to autocorrelation. All regressions include the calendar and temperature controls detailed in Section 4.3. F-Stat and S-W F-Stat reflects the first-stage regression F-statistic and the Sanderson-Windmeiher F-statistic, respectively. K-P LM is the Kleibergen-Papp rk Lagrange-Multiplier test statistic for weak IVs. Statistical Significance $^{*}p < 0.10$, $^{**}p < 0.05$, and $^{***}p < 0.01$.

B PPA Expiry Price Decomposition

In this section, we undertake an analysis to decompose the factors behind the large average peak price increase (representing a 120% increase) from 2020 to 2021. The movement from 2020 to 2021 saw a number of changes in addition to the expiry of the PPAs, including a 3% increase in average demand, an approximately 60% increase in natural gas prices, and a $10/tonne increase in the carbon price imposed on generators operating in Alberta. This helps us better understand what role various factors played in the price increase during this important period of our sample.

To perform this exercise, we start by constructing the competitive benchmark for 2020, as per the methodology detailed in Section 4.1. We then do so again for 2021, but holding constant the levels of average demand, the average natural gas price, and carbon price at the 2020 levels.[62] This allows for the shape of demand and prices to differ between the scenarios, but removes the level effect of these key factors. We remove each of these factors one at a time to understand their relative effects.

Figure B1: Decomposing the Factors Behind the 2020 to 2021 Price Change



Notes. Considers peak hours (6:00 AM - 10:00 PM). 2020 values inflation-adjusted to 2021 dollars.

Figure B1 provides the results of this decomposition. We find a modest increase in the 2021 competitive benchmark ($2.59/MWh) when all three factors are held at their 2020 levels, indicating

[62]More specifically, we multiply the 2021 daily gas price by the ratio of the average gas prices in 2020 and 2021, we multiply the 2021 hourly demand by the ratio of the average demand in 2020 to 2021, and adjust the 2021 carbon price downward from $40/MWh to $30/MWh, the level observed in 2020. The demand and gas adjustments maintain the 2021 shape, but equalize the average levels across 2020 and 2021.

the change in supply mix and/or change in shape of demand had a small cost-increasing effect. This could be explained by several coal-to-gas conversions changing the marginal cost of several plants, or more peakedness to the load shape.

Next, we start relaxing the restrictions on the primary cost drivers: demand, natural gas prices, and carbon prices. Allowing demand to reach its actual 2021 level, roughly 3% higher than 2020, has a large effect on the benchmark, increasing it by \$14.69/MWh. Allowing natural gas to rise to its 2021 level, over 60% higher than 2020, increases the benchmark by a further \$6.59/MWh. The incidence of natural gas costs reflects a mix of natural gas and coal plants being on the margin, thus is less than what might be expected if gas were on the margin in every hours. Lastly, increasing the carbon price by \$10 per tonne in 2021 adds \$2.34/MWh to the benchmark price, again reflecting what would be expected from a mix of natural gas and coal plants being on the margin.[63]

This analysis suggests that the combination of a change in the load shape and supply mix, demand, natural gas price, and carbon price account for 37% of the observed change. The remaining 63% of the change in the observed prices in 2020 and 2021 is due to a change in bidding behaviour. These results are consistent with average bid markups observed in peak hours reported in Table 2. In 2020, the implied markup was \$15.73/MWh. In 2021, this rose to \$59.81/MWh —an increase of \$44.08/MWh from one year to the next.

C 2021 Bidding Behaviour

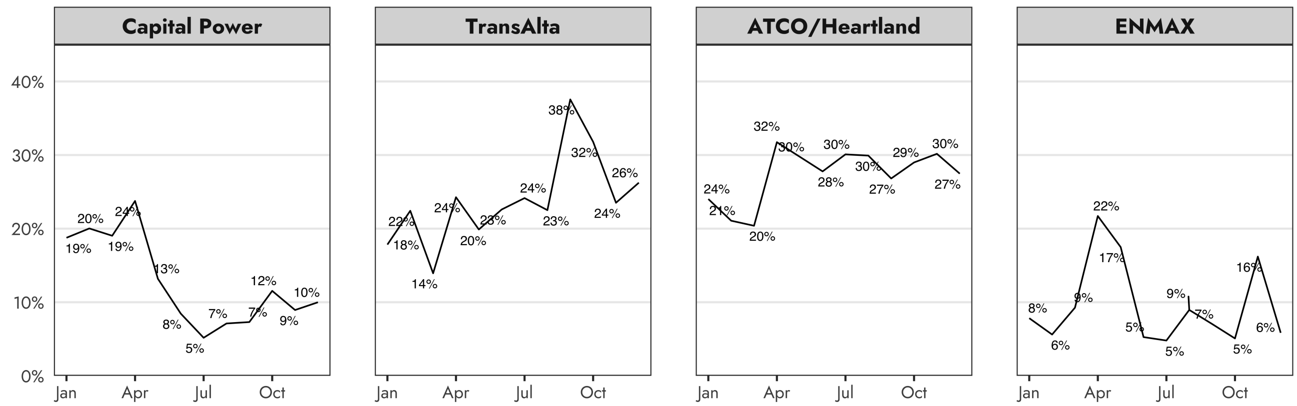
In this section, we present additional details on the firms' offer behaviour in 2021. Our main analysis summarizes observed offer behaviour at the annual level. However, within 2021 we observe changes in firm bidding behaviour, most notably within Capital Power. In Figure C1, we present the share of thermal capacity economically withheld by month across the four largest firms, the first three of whom received offer control from the expired PPA units. The share withheld by Capital Power ranges between 19% and 24% in the first 4 months, before falling into the 5% to 13% range for the remainder of the year. Whereas, the two other firms receiving expired PPA offer control, Heartland and TransAlta, see their share of capacity economically withheld staying roughly flat to rising throughout 2021.

The distinct change in Capital Power's share of thermal capacity that is economically withheld suggests that it adjusted its offer behaviour after the first four months of 2021. Figure C2 presents Capital Power's cumulative offer curves for two periods in 2021. For the first four months of the year, Capital Power followed a bidding strategy of raising their offer prices above marginal cost for the last 30% of their capacity. Whereas, from May onwards, this transitioned to only the final 10% to 15% of their offer curve being priced up.

One possible explanation for the distinct change in Capital Power's offer behaviour is that

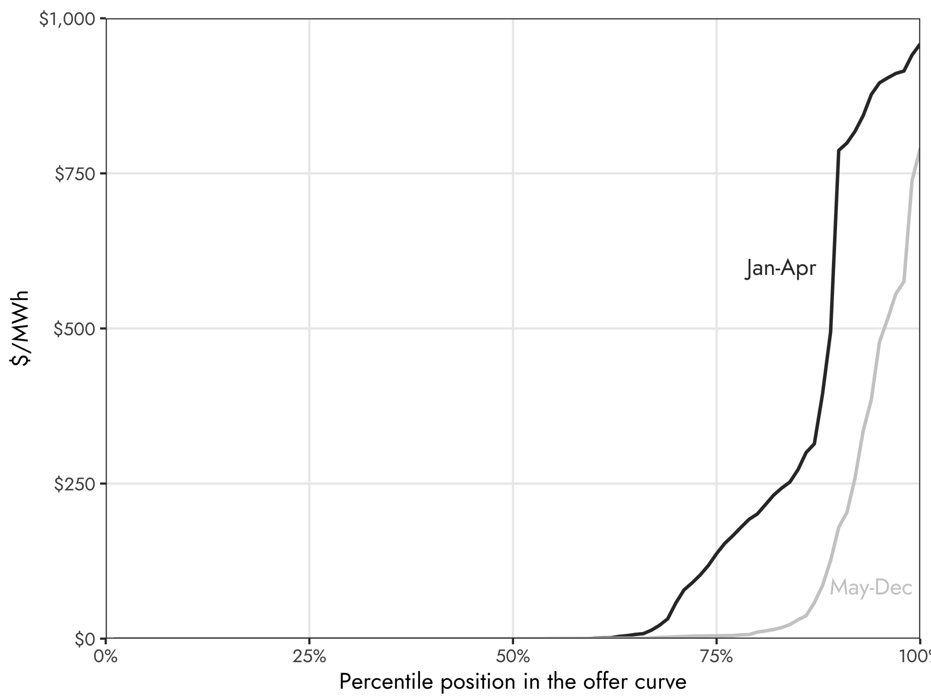
[63]The effect of the carbon price is also mitigated by the fact that Alberta's large emitter program only imposes the carbon price on a unit's emission intensity that exceeds an industry benchmark level reflecting the emissions intensity of a combined cycle gas turbine. This dampens the increase in the marginal cost impact of a carbon price increase. For additional details, see Brown et al. (2018) and Olmstead and Yatchew (2022).

Figure C1: Economic withholding share of capacity, 2021



Notes: An offer is deemed economically withheld when the marginal cost of that particular generator block is less than the market-clearing price, allowing for a $10/MWh buffer on our estimate of marginal cost to allow for measurement error, but the offer price for the block is above the market clearing price. We include only coal, combined cycle natural gas, simple cycle natural gas, and dual fuel offers in peak hours (6:00 AM - 10:00 PM) in this figure.

Figure C2: Cumulative offer curves for Capital Power in 2021



Notes: We include only coal, combined cycle natural gas, simple cycle natural gas, and dual fuel offers in peak hours (6:00 AM - 10:00 PM) in this figure.

it adjusted its forward contract position after the first four months of the year. The literature has found that increased forward positions reduce firms' incentives to exercise market power (e.g., Wolak (2000) and Bushnell et al. (2008)). We corroborate this suggestive evidence of a change in forward contracting with records from Capital Power's annual reports from 2020 and 2021. At the end of 2020, Capital Power reported only 29% of their coming year, 2021, production to be hedged.[64] This compares to, at the end of 2021, their reported coming year (2022) hedge level at a much higher 72%.[65] Ideally, we would have visibility of within year hedging levels, but in the absence of this information, this information indicates a large increase in corporate hedging activity in 2021. And while the reported values are only shown for 2022, it may have coincided with balance-of-year 2021 hedging.

D Supplementary Tables and Figures

Table D2: Statistical Comparison of Mean Markups by Year

	2013	2014	2015	2016	2017	2018	2019	2020
2014	11.88							
	(0.00)							
2015	18.54	7.35						
	(0.00)	(0.00)						
2016	29.78	20.45	12.88					
	(0.00)	(0.00)	(0.00)					
2017	25.25	15.03	7.71	-4.57				
	(0.00)	(0.00)	(0.00)	(0.00)				
2018	19.56	7.99	0.03	-15.90	-8.76			
	(0.00)	(0.00)	(0.98)	(0.00)	(0.00)			
2019	17.69	6.10	-1.59	-15.99	-9.85	-1.80		
	(0.00)	(0.00)	(0.11)	(0.00)	(0.00)	(0.07)		
2020	21.36	10.28	2.60	-11.78	-5.71	2.90	4.46	
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	
2021	4.93	-8.82	-17.32	-35.14	-26.75	-18.96	-16.29	-21.35
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)

Notes. The reported numbers reflect the t-statistic from a comparison of means test with unequal variances. P-values associated with the null hypothesis that the means are equal are reported in parentheses.

[64] 2020 hedging levels are reported here: https://www.capitalpower.com/wp-content/uploads/2021/02/2020-Q4-Presentation.pdf.

[65] 2021 hedging levels are reported here: https://www.capitalpower.com/wp-content/uploads/2022/02/2021-Q4-Presentation.pdf.

Table D3: Average Observed Price, Competitive Price, and Market Power Measures - Off-Peak Hours (in 2021 CAD$s)

Year	Observed Price ($/MWh)	Competitive Price ($/MWh)	Markup ($/MWh)	Market Performance ($MP(\mathcal{T})$)
2013	32.63	21.90	10.74	0.30
2014	32.37	24.33	8.04	0.23
2015	22.07	20.46	1.61	0.08
2016	17.67	19.53	-1.85	-0.09
2017	20.16	24.04	-3.89	-0.18
2018	37.91	37.66	0.26	0.02
2019	40.89	39.83	1.06	0.05
2020	31.10	35.15	-4.05	-0.11
2021	58.01	46.30	11.71	0.21

Notes. Off-peak hours are defined by 12:00 AM - 6:00 AM and 10:00 PM - 12:00 AM. Competitive prices reflect the average of the Monte Carlo simulated competitive prices. $MP(\mathcal{T})$ is defined in (1). Markup is the difference between the observed and competitive prices. All $'s are inflation-adjusted to 2021 Canadian $s.

Table D4: Statistical Comparison of Estimated Lerner Index by Year and Supply Cushion Quartiles Q1 and Q2

	2013		2014		2015		2021	
	Q1	Q2	Q1	Q2	Q1	Q2	Q1	Q2
2016	51.84	91.51	18.53	101.00	26.65	18.02	79.20	42.06
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
2017	76.25	120.50	36.95	130.23	43.76	34.52	104.33	66.56
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
2018	25.82	94.78	2.67	104.61	10.20	15.95	54.83	41.38
	(0.00)	(0.00)	(0.10)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)
2019	33.46	87.56	4.79	97.36	12.87	12.34	66.95	35.33
	(0.00)	(0.00)	(0.03)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
2020	47.62	322.99	11.44	326.50	19.73	82.24	83.15	209.64
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)

Notes. The reported numbers represent the chi-squared statistic that evaluates if the coefficients on the supply cushion-year interactions in (2) are statistically significantly different. For example, the number reported in the 2013 - 2016 Q1 cell reflects the test that the supply cushion Q1 coefficient is equivalent in 2013 and 2016. P-values for the null hypothesis that the coefficients are equal are reported in parentheses. This table focuses on the bottom two quartiles Q1 and Q2 of the supply cushion-year interactions.

E Evaluating the Ability and Incentive to Exercise Market Power

We employ the modeling framework in Wolak (2000, 2003) and McRae and Wolak (2014) to summarize how firms' incentive and ability to exercise market power varies over our sample. In this setting, a generator's ability to exercise market power depends on the properties of the residual demand function it faces, where residual demand represents market demand minus its rivals' supply offers. This literature develops an inverse semi-elasticity measure of the residual demand function to quantify the ability of a generator to unilaterally exercise market power.

The modeling framework assumes that firms unilaterally maximize their expected profit. Under certain conditions, the model reduces to finding the set of *ex post* profit-maximizing price and quantity pairs for any realized level of residual demand. The implication of this finding implies that the following condition holds at the market price p_t for each hour t and supplier i:

$$p_t - MC_{it} \;=\; -\frac{RD_i(p_t)}{RD_i'(p_t)} \tag{5}$$

where MC_{it} is the marginal cost of the highest cost MWh produced by firm i and $RD_i(p_t)$ and $RD_i'(p_t)$ denote firm i's residual demand function and its derivative at p_t. The inverse semi-elasticity of the residual demand curve is defined as:

$$\eta_{it} \;=\; -\frac{1}{100} \times \frac{RD_i(p_t)}{RD_i'(p_t)}. \tag{6}$$

Because generators' supply functions are discrete step-functions in practice, a generator's residual demand function is a step-function. As a result, (5) will not typically hold with equality. Despite this empirical difficulty, under the simplified modeling framework above, the inverse semi-elasticity measure implies that periods of elevated prices and price markups are associated with higher values of the inverse semi-elasticity measure (McRae and Wolak, 2014).[66] Estimating (6) requires us to compute the slope of the residual demand step-function at the market-clearing price. Following Hortacsu and Puller (2008), we employ a local-linear kernel smoothing approach with a 50 MWh bandwidth on the observed residual demand function to estimate $RD_i(p_t)$ and $RD_i'(p_t)$.

A generator's incentive to exercise market power can differ from its ability because of the presence of fixed-price forward contract obligations signed in advance of wholesale market competition. McRae and Wolak (2014) provide an augmented inverse semi-elasticity measure that accounts for the presence of forward contracts. In particular, in this formulation a generator's incentive to exercise market power depends on the properties of its residual demand function net of the firm's

[66] Brown and Eckert (2021) use data from Alberta's wholesale market in 2013 and find that the *ex post* unilateral profit maximizing offer curve can violate the requirement that offer curves are monotonically increasing. This arises because of the residual demand functions in Alberta can be highly non-linear. As a result, the *ex post* optimal price-quantity pair can deviate from that defined by (5) under certain conditions. Consequently, the results in this section should be viewed with the understanding that they capture the broader properties of a generator's residual demand function and the corresponding strategic environment.

forward position. The net inverse semi-elasticity measure is characterized as:

$$\eta_{it}^{C} \;=\; -\frac{1}{100} \times \frac{RD_i(p_t) - F_{it}}{RD_i'(p_t)}. \tag{7}$$

where F_{it} represents generator i's forward quantity in hour t. Notice that given $RD_{it}'(p_t) < 0$, $\eta_{it}^{C} < 0$ can arise if $RD_i(p_t) < F_{it}$ (i.e., when generator i is a net buyer in the wholesale market).

We do not have data on each generator's forward positions. We follow the approach in Hortacsu and Puller (2008) and estimate generators forward contracts using observed bidding behaviour (see their Proposition 1). More specifically, a generator's forward contract position reflects the quantity where the firm's supply function intersects its marginal cost function.

Figures E3 – E8 plot the inverse and net inverse semi-elasticity measures by firm over our sample period. The market-clearing pool price is provided to illustrate the relationship between the measures of the ability and incentive to exercise market power and the corresponding pool price. For expositional ease, the plots represent 30-day moving averages of the hourly variables.

In general, there is a strong positive correlation between the pool price and the inverse semi-elasticity measures.[67] During periods with a high inverse semi-elasticity measure (e.g., 2013, 2014, 2021), we observe a high pool price. In 2016 and 2017, there is a significant reduction in both the pool price and the semi-elasticity measures. This corresponds with the transition of the PPAs to the Balancing Pool and our lowest values of market power execution (recall Table 2). There is an increase in firms' ability and incentive to exercise market power in 2018 – 2020 corresponding with the retirement of several large coal assets offered by the Balancing Pool. In 2021, when we observe a large increase in the pool price, we see a substantial increase in the ability and incentive to exercise market power for the majority of the firms.

It is informative to briefly discuss the inverse semi-elasticity measures of several key firms and how it relates to the observed degree of economic withholding summarized in Figure 13. Figure E3 demonstrates that TransAlta experiences a sizable increase in its ability and incentive to exercise market power in 2021 as it receives the expired PPA assets. This coincides with a significant increase in economic withholding in Figure 13. Similarly, in Figure E5, ATCO/Heartland experiences a considerable increase in its incentive and ability to exercise market power in 2021 when it receives several expired PPA assets. Figure 13 shows that its share of economically withheld capacity increases by 12 additional percentage points between 2020 and 2021.

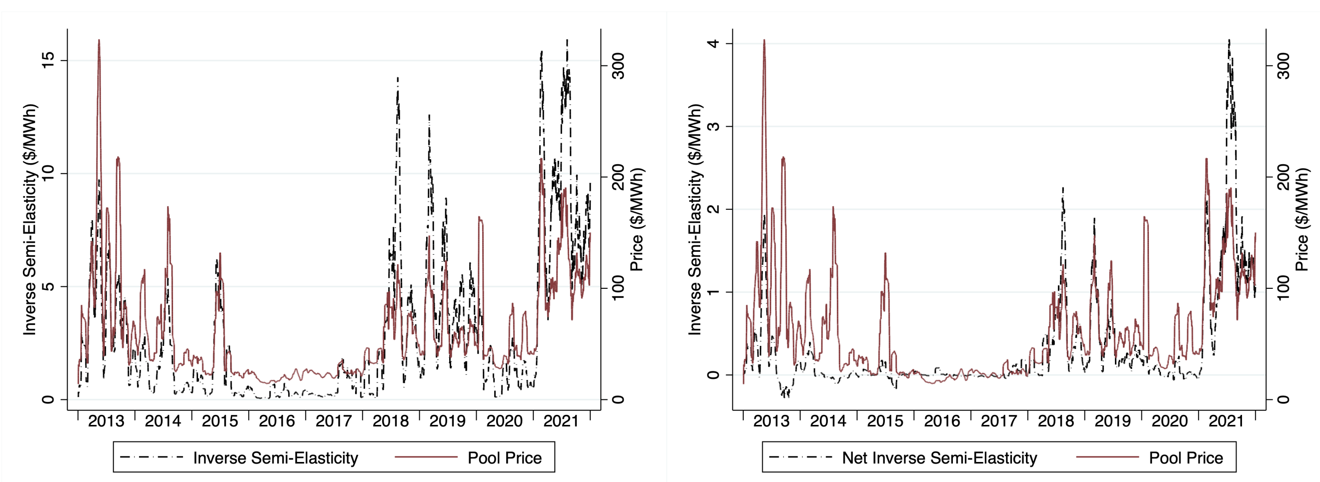
Figure E7 demonstrates that TransCanada, which had offer control over a sizable portion of the PPAs early in the sample, had considerable ability and incentive to exercise market power in 2013 and 2014. Figure 13 demonstrates that TransCanada exercised market power in these years. After 2015, TransCanada's offer control decreased as the PPA assets were transferred to the Balancing Pool resulting in it becoming a small firm. Figure E8 demonstrates that the Balancing Pool had

[67] For TransAlta, Capital Power, ENMAX, and ATCO/Heartland, the large strategic firms throughout the entire sample 2013 – 2021, the average correlation coefficient of the pool price and the inverse semi-elasticity measure is 0.83.

considerable ability to exercise market power over the period 2018 – 2020.[68] However, as shown in Figure 13, it chose not to exercise market power and instead bid its assets near its marginal cost of production.

To summarize, these results are consistent with certain large firms, some of which had offer control of PPA assets, having both the ability and incentive to exercise market power early in our sample period. We observe these firms economically withholding. When the PPA assets were transitioned to the Balancing Pool, firms had limited ability and incentive to exercise market power. This is likely driven in part by the fact that the Balancing Pool bid its assets at or near its marginal cost resulting in the large firms facing a residual demand function that was not conducive of unilateral market power execution. Starting in 2018, the market became more "tight" as several coal units retired. We observe an increase in firm's abilities and incentive to exercise market power and the equilibrium pool price. However, firms' abilities to exercise market power in these years was likely mitigated by the continued competitive offer behaviour by the Balancing Pool. Finally, in 2021 the PPA assets are returned to their original owners. For TransAlta and ATCO/Heartland, we observe a large increase in economic withholding, corresponding with a large increase in these firms' inverse semi-elasticity measures. This increase likely arises from the fact that there is no longer a large firm bidding its capacity at or near marginal cost. Rather, this capacity was offered by strategic firms that chose to economically withhold in equilibrium, elevating each large firm's residual demand inverse semi-elasticity.

Figure E3: TransAlta - Inverse Semi-Elasticity Measures and Pool Prices



[68]MSA (2018) note that the Balancing Pool did not actively participate in forward markets. However, because our measure of forward contracts are constructed using offer behaviour and the Balancing Pool consistently bid at or near its marginal cost of production, we estimate a high forward contract coverage. This creates challenges with interpreting the net inverse semi-elasticity results for the Balancing Pool.

Figure E4: Capital Power - Inverse Semi-Elasticity Measures and Pool Prices

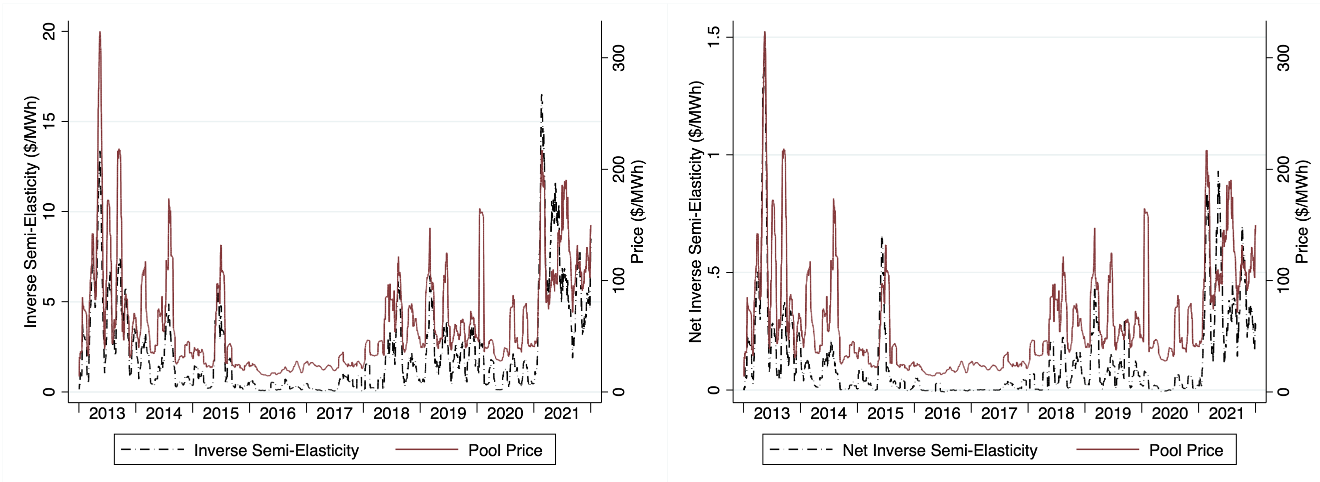


Figure E5: ATCO/Heartland - Inverse Semi-Elasticity Measures and Pool Prices

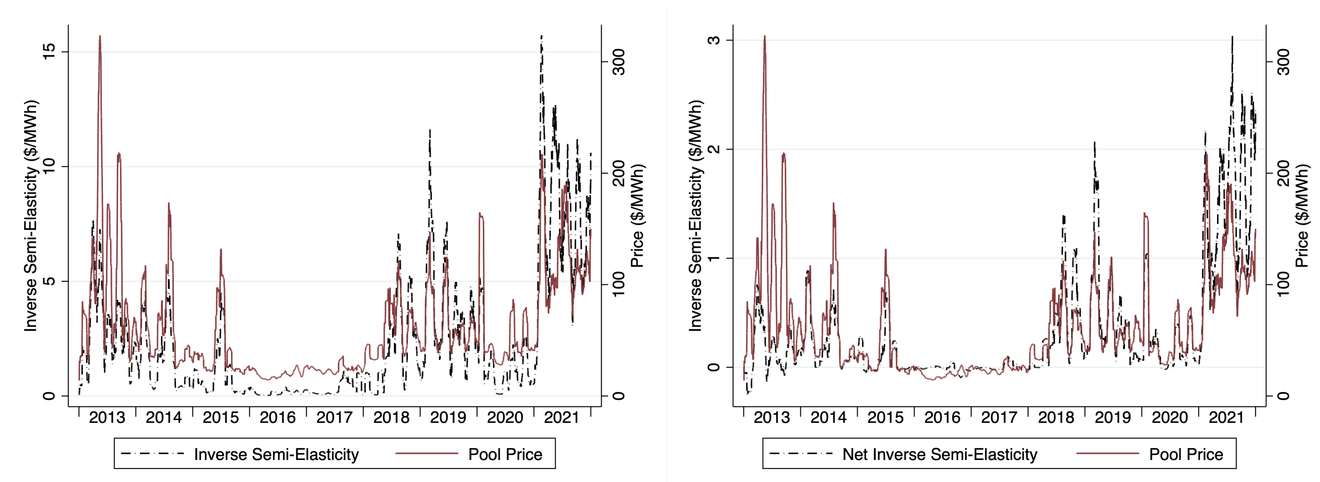


Figure E6: ENMAX - Inverse Semi-Elasticity Measures and Pool Prices

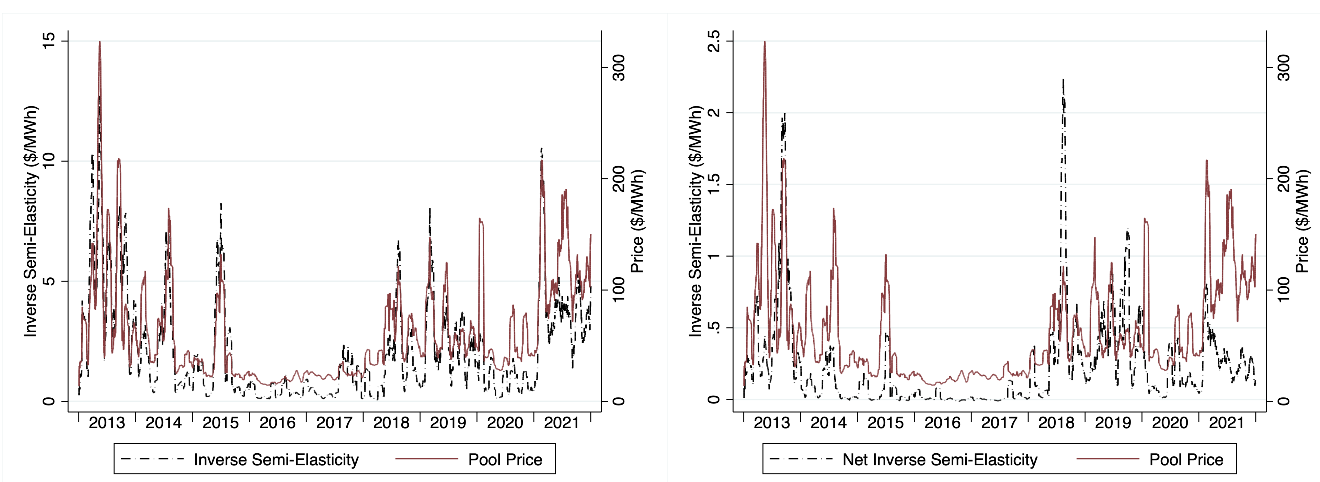


Figure E7: TransCanada - Inverse Semi-Elasticity Measures and Pool Prices

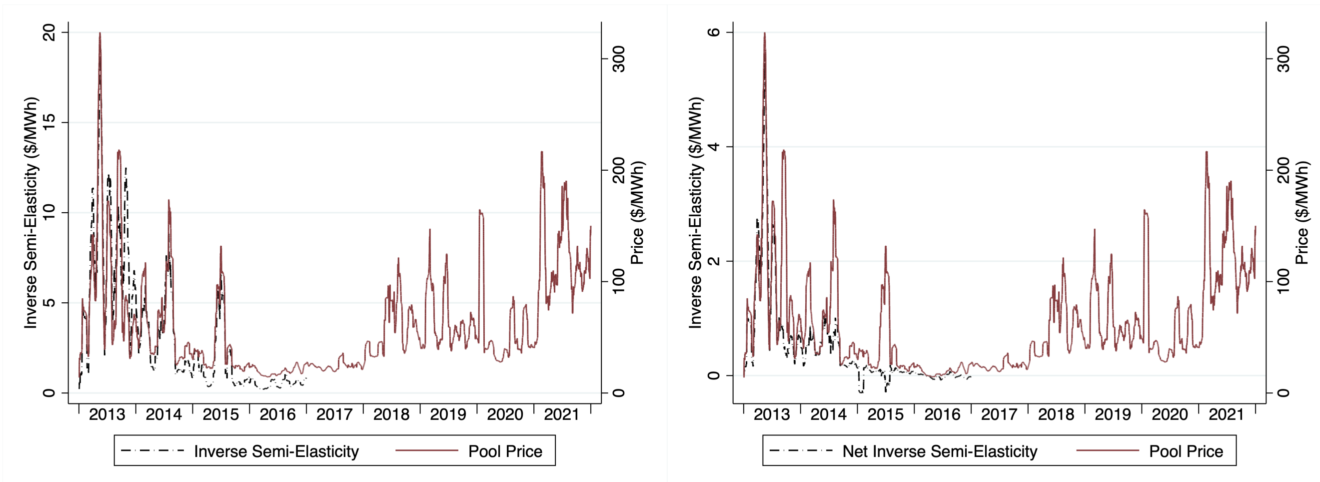
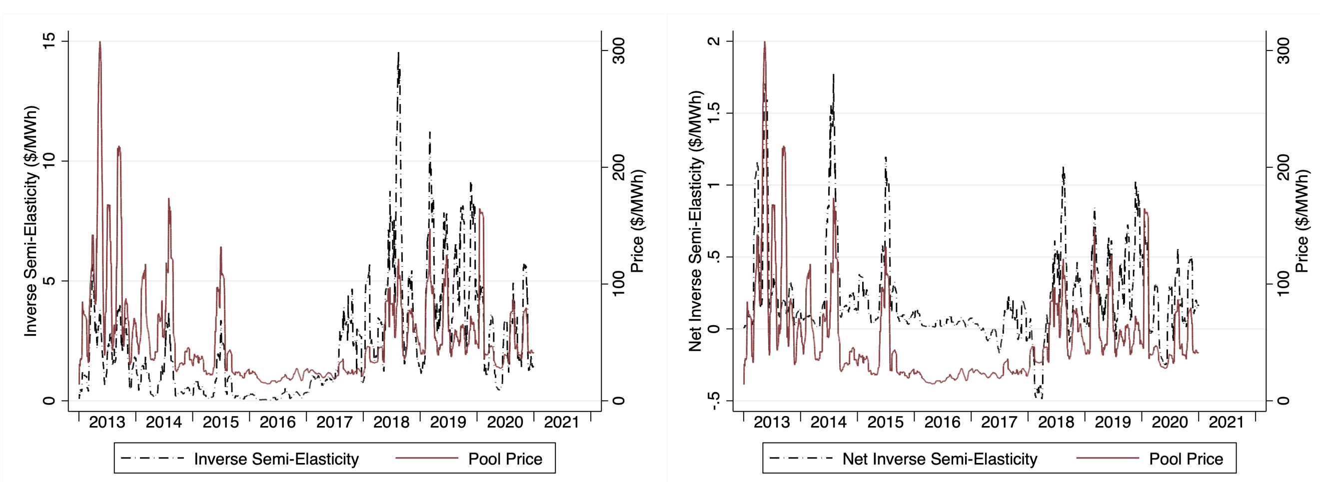


Figure E8: Balancing Pool - Inverse Semi-Elasticity Measures and Pool Prices



F Summary of PPA Unit Offers

In this section, we describe the offer behaviour on the PPA units over time. For each PPA unit, we separate the offers into whether they were offered by the Balancing Pool or by a large strategic generator (either the PPA buyers pre-2017 or PPA owners in 2021). We further segment these two categories into whether the firm that had offer control over the PPA unit was pivotal or not using the Residual Supplier Index defined in (4). Figure F9 presents the share of offers on each PPA asset that are economically withheld by whether or not they were offered by the Balancing Pool or a strategic generator, and by whether or not the firm with offer control is pivotal in the relevant hour.

Figure F9 demonstrates that the offers on the PPA units are rarely economically withheld when the Balancing Pool has offer control. There is no clear relationship between the degree of economic withholding and the Balancing Pool's pivotal supplier status.[69] The Balancing Pool offers the PPA units at prices above marginal cost (plus a \$10/MWh buffer) in less than 2% of all of its offers into the wholesale market.[70] This is consistent with the assertion by the Alberta Market Surveillance Administrator that the Balancing Pool offers the PPA assets at or below marginal cost (MSA, 2018).

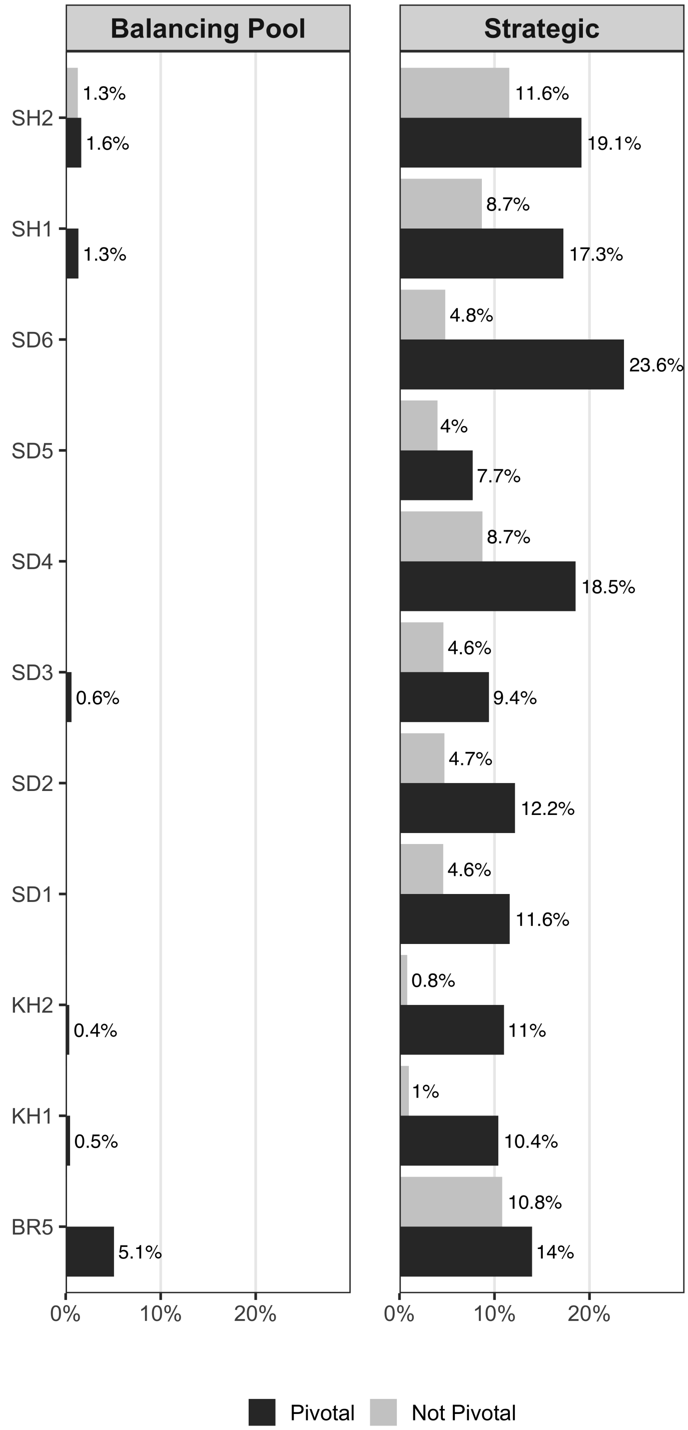
Alternatively, Figure F9 demonstrates that when the PPA assets are offered by a strategic generation firm, we observe higher levels of economic withholding. Further, the degree of economic withholding is elevated when the strategic supplier is pivotal. These results are consistent with the Balancing Pool offering the PPA assets at or below marginal cost. When the PPA assets are offered by a strategic firm, they are used to exercise market power and this effect is larger when the strategic firms has elevated ability to exercise market power.

We carried out supplemental analyses that demonstrates that the offers on the PPA units changed abruptly when the PPA assets were being transitioned from the PPA buyers to the Balancing Pool in 2016 - 2017. Consistent with the results in Figure F9, the assets transitioned from being priced-out of the market (i.e., economically withheld) in certain hours to being offered at or below marginal cost in essentially every hour. Detailed results are available upon request.

[69] We find a small degree of economic withholding on the unit Battle River 5 (BR5) when the Balancing Pool has offer control and is pivotal. Inspection of the data reveals that this reflects offers in 2018 where the Balancing Pool offered this unit in at approximately \$11/MWh higher than our marginal cost estimate. The Balancing Pool was deemed to be pivotal in all peak hours during this period. Consequently, the elevated economic withholding in Figure F9 likely reflects measurement error in our marginal cost estimate on this unit in 2018 rather than an indication of this unit being used to exercise market power via economic withholding which typically occurs at much higher prices in Alberta (i.e., in excess of \$100/MWh).

[70] If we reduce this measurement error buffer to \$5/MWh, the percentage of offers increases to approximately 5%.

Figure F9: Share of Discretionary Offers Economically Withheld on PPA Assets by Pivotal Status and Offer Control



Notes. An offer is deemed economically withheld when the marginal cost of that particular generator block is less than the market-clearing price, allowing for a $10/MWh buffer on our estimate of marginal cost to allow for measurement error, but the offer price for the block is above the market clearing price. A unit is deemed to be pivotal in an hour if it is offered by a firm with an RSI value defined in (4) of less than 1. We include only offers in peak hours (6:00 AM - 10:00 PM) in this figure.

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