Market Power and Renewables: The Effects of Ownership Transfers[*]

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Abstract

The introduction of renewable energy sources (RES) changes the shape of an electricity system's supply curve. In a perfectly competitive market, this causes a downward pressure on equilibrium prices (the merit-of-order effect). In the presence of market power however, introducing or transferring RES assets has ambiguous effects, depending on the degree of *dilution* of the RES capacity in the firms' portfolios. Using a detailed model of an electricity market, we quantify this effect empirically by finding equilibria under different counterfactual scenarios of RES ownership transfers and expansions. When keeping the total amount of RES constant, we find that transfers from the fringe to strategic players yield positive increases in prices. We call this phenomenon the *dilution* effect. In addition, we find that equilibrium prices increase by higher amounts when the strategic firms' new portfolios are more diluted. Finally, we show that following a net expansion of RES capacity, the merit-of-order effect dominates the *dilution* effect, thus leading to lower prices than without the expansion. However, the size of the counteracting force from the *dilution* effect largely depends on the market power of the new capacity's owner.

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1 Introduction

Over the past few years, electricity markets around the world have seen important changes in their energy portfolios as new sources have been introduced (e.g. wind and solar) and others have been retired or penalized through taxes (e.g. non-refurbished nuclear plants and coal plants). These changes continue nowadays as a number of incentives have been put in place to curb the greenhouse gas emissions associated with the production of electricity (e.g. production subsidies, feed-in-tariffs (FiT), and renewable portfolio standards (RPS)). Although some of the consequences of those policies have been studied (see for instance Borenstein [2012], Gowrisankaran et al. [2016], Reguant [2018], and the references cited therein), little is known about the effects of these mechanisms on the producers' market power. This paper examines the relationship between changes in electricity production portfolio composition and the resulting electricity spot prices.

When there is an expansion of the amount of renewable energy sources (RES), the system's supply curve shifts to the right and its intersection with the demand curve occurs at a lower price than before the expansion. This effect is known as the merit-of-order effect (henceforth MoE). However, partial ownership of RES from firms with market power may counteract the MoE. This phenomenon is what we call the *dilution* effect. By *dilution* effect we mean the resulting decrease in proportion of conventional sources in a firm's portfolio configuration after adding RES capacity. This is not a simple diversification effect because it includes a net expansion of the firm's capacity (more of the system's capacity is owned by a market power user). Since it is not obvious how to disentangle those two forces, we make the distinction between the dilution and diversification terms, in contrast with the existing literature. In the presence of market power and the dilution effect, strategic firms partially internalize the shift of the supply curve caused by the MoE by withholding capacity from their conventional generation sources, thus effectively shifting their individual bid curve to the left and causing an upward pressure on prices. This is one of the main takeaways in the theoretical work of Acemoglu et al. [2017] for the case of symmetric firms and symmetric portfolio compositions. Brown and Eckert [2018] expand on this by allowing for asymmetric amounts of RES in the

firms' portfolios.[1] Genc and Reynolds [2019] study the effects of ownership and the MoE when adding RES capacity into the system.[2]

Our paper continues this work by providing an empirical analysis of the effect from RES ownership transfers and expansions on wholesale electricity prices, quantifying the dilution effect in presence of market power, and comparing it to the merit-of-order effect. Note that we will not be able to disentangle diversification effects from market power within the dilution effect. Indeed, an ideal experiment to do this would be to take all firms' total capacities as fixed, and then continuously reshuffle their portfolio mix. Such an experiment has little or none similarities with current or previous market reorganizations. Portfolio dilution in these markets arises in part because of the different incentives to adopt RES such as RPS and FiTs. However, the long term existence of such incentives is threatened in several places around the world. One possibility is that payments cease to exist for FiTs and the idle capacity from non-strategic players gets transferred to the strategic players.[3] The effects of this return to normality on wholesale prices is an open empirical question. To the best of our knowledge, our work is the first to empirically test for the effects of portfolio dilution from RES additions and transfers on the wholesale electricity market. One of the advantages of our work is that by using data we can assess these effects in the presence of asymmetric firms and at different levels of correlation between RES output and load. From an economics perspective, our paper contributes to the literature by confirming some theoretical results on the interaction of dilution and market power in electricity markets. In addition, from a regulatory and policy analysis perspective, our results contribute by quantifying some hidden or ambiguous effects from the introduction of large scale renewable sources into the electricity production mix.

Many electricity markets are vertically separated into generation, transmission and distribution segments. In these markets (e.g. MISO, NYISO, PJM, ERCOT, IESO, CAISO)[4], the

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[1] However, both firms start with no RES at the moment of the procurement auction.

[2] Their empirical results confirm that prices decrease by approximately 1% when investment for wind capacity quadruples.

[3] The current debate in Ontario, where our data come from, is the elimination of incentives for the adoption of RES. See https://business.financialpost.com/commodities/energy/boralex-invenergy-ontario-clean-power-projects-hit-by-ford-1 .

[4] Midcontinent Independent System Operator (ISO), New York ISO, Pennsylvania New Jersey Maryland Interconnection, Electric Reliability Council of Texas, Independent Electricity System Operator (Ontario),

production effort is undertaken by sets of independent producers of electricity that typically own different plants with different technologies. These producers meet in bidding markets usually overseen by an auctioneer entity, the independent system operator. This operator takes all the firm-specific supply curves and constructs a market supply curve by sorting the bids from lowest to highest cost to the system according to the asking prices, this is known in the industry as the merit order. The operator then combines each of these supply curves with its forecast for demand for each hour, the intersection is the spot electricity price. Further details on the functioning on this type of market, and specifically on the Ontario market, are explained later in the paper. Structural changes in these markets can be stylized as competition models where firms have perfect information on the others' marginal cost curves. This is a reasonable assumption since in most markets electricity producers have to comply with administrative forms that reveal to the public their nameplate capacities for different sources and the firms interact several times a year for long periods of time.

Although the exact impact of expanding RES is most likely market specific, we believe we can extract general qualitative impacts from the study of a particular market. We choose the case of Ontario and its Independent Electricity System Operator (IESO) to answer these questions. This market is vertically disintegrated with enough variation in its generating sources and in the number of competitors. We model the electricity market following the ideas developed by Borenstein and Bushnell [1999] and Bushnell et al. [2008], and more recently by Brown and Eckert [2016]. The first paper introduces an industry marginal cost curve expressed as a step function that can be fully characterized using engineering parameters and fuel prices. Then, they separate producers into two categories: strategic and non-strategic (price-takers) firms. The former have the capacity to influence the hourly equilibrium price because of their importance in the market or because of their atypical cost structure (e.g. low start-up costs). The latter are firms that own very small nameplate capacities or that have long-term contracts with the system operator or with downstream firms. Therefore, they have negotiated prices much before the spot price is formed. This second category of firms is important to the specific case of Ontario as a large proportion of the producers belong to

and California ISO, respectively.

it. The other two papers refine the estimation techniques by exploring the consequences of the presence of forward contracts and the use of different instrumental variables.

The presence of imports and exports in the Ontario system implies that firms face a different demand than just the domestic one. Following Bushnell et al. [2008], we account for this by estimating the net exports supply and adding it to the domestic demand to get the residual demand that firms face. We estimate this model using data from multiple and publicly available sources. We use weather data from the National Oceanic and Atmospheric Administration (NOAA), hourly production, demand and capacity data from the Independent Electricity System Operator (IESO), firm-level aggregate capacities from financial statements and fuel spot prices public databases. We focus on the period 2010 - 2012.

Expanding on the stylized theoretical Cournot competition models in Acemoglu et al. [2017], Brown and Eckert [2018], and Genc and Reynolds [2019], we add the fringe's production decision and show in a theoretical result that it is possible to characterize the effects of ownership transfers on wholesale electricity prices. However, we show that this result holds under strong market assumptions such as symmetry among the firms.[5] This is our analysis starting point and it provides a natural motivation: only an empirical analysis can shed light on more realistic configurations that are otherwise intractable to solve analytically. In particular, we provide a framework to study RES capacity changes regardless of the degree of asymmetry among the competitors.

We estimate a detailed model of the Ontario electricity market to run simulations that consist of finding the new hourly equilibrium prices under different allocations of RES among market participants using the reaction functions estimated from the data. Our results show that, by keeping the total amount of RES constant in the system, transfers of that capacity from the fringe into the strategic firms give place to positive increases in prices of magnitudes that depend on the quantile of RES capacity transferred. These effects are net of the MoE because there are no additions to the system's RES capacity. The reason behind this phenomenon is that strategic firms partially internalize the increase in dilution by withholding conventional capacity. Even though we prove this insight theoretically, an empirical model is

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[5]This is also the case in the literature mentioned earlier.

needed to fully quantify these effects when firms are asymmetric. We also find that portfolio dilution is a strong determinant of wholesale price changes. As the strategic firms' portfolios become more diluted, equilibrium prices increase by greater amounts. In other words, the expansion of the strategic firms' portfolios from adding RES capacity yields to more expensive electricity, contrary to the effects from a simple MoE. It is important to note that since we use actual production data from wind and solar, we are addressing issues of stochasticity of output which is typical of non-dispatchable sources.[6] When we add RES to the entire system, the merit order and the dilution effects combined yield lower prices relative to the equilibrium outcome with no added RES. Yet, the size of this effect depends on the degree of market power of the firm that owns the new RES capacity and its own dilution level.

The rest of the paper is structured as follows. In section 2 we describe the institutional framework of the Ontario electricity generation market. In section 3, we present the data used to estimate electricity demand and supply functions. In section 4, we present the model and estimate the demand function. In section 5 and section 6 we present the goodness-of-fit of our model as well as the main results. We conclude in section 7.

2   Ontario Electricity Generation Sector

First, we present the state of regulation in this industry; then we describe the Ontario's energy mix, the various existing contracts between regulators and firms and finally, the main strategic players in this market.

2.1   Regulatory framework

The Ontario market remains highly regulated. Its operation relies on a bidding market overseen by the Independent Electricity System Operator (IESO), a province- and federal-owned company. The IESO's roles in the market are to (1) ensure the market operates correctly, (2) determine electricity prices in real time, (3) distribute electricity from suppliers to consumers, and (4) introduce policies decided at the provincial and/or federal level. The

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[6]There is also a tiny fraction of biomass used in the system, but we shall neglect it. Therefore, throughout the paper, we shall use the terms RES and non-dispatchable sources interchangeably.

latter role is shared with the Ontario Energy Board (OEB), which also monitors closely the wholesale electricity market but has a stronger role than the IESO in making and enforcing policies that encompass a larger view of the market.

The bidding market consists of a 3-step process. First, the IESO publishes a forecast of hourly demand from the next day to 30 days after. With these predictions, generating firms submit a quantity-price bid at least 24 hours before the actual dispatch. This bid can be a set of one or more quantities that they would be able to produce at a given price. Finally, the IESO distributes electricity in response to actual demand by dispatching the lowest bid first. The final price is the intersection between the aggregate bidding schedule and the actual demand at each hour. Since we are mainly interested in wholesale prices, considerations about prices paid by consumers are beyond the scope of this paper.

2.2 Electricity production

Ontario's production system is quite large as its capacity is almost equal to twice the province's average hourly demand. In fact, throughout our sample (from 2010 to 2012), the average hourly load is equal to 17,751 MWh, while the average available capacity is equal to 28,432 MW. From 2010 to 2012, this capacity is composed of five main sources: nuclear energy (around 56% of total production), hydroelectricity (23%), natural gas (15%), wind power (2-3%) and finally coal (which was later phased out, went from 8% of production in 2010 to 3% in 2012).

Within this total capacity, it is possible to separate production assets in two groups that differ in how they interact with the markets. The first group, named "regulated" assets, produces electricity under a contract that sets a fixed price for generation. There are different types of contracts that imply a guaranteed price. The main one is the specific contract between the OEB and two companies: Ontario Power Generation (OPG) and Bruce Power (Bruce). This contract is the most important as it impacts nearly 15,000 MW of production capacity on average (more than half of Ontario's total capacity). All of Ontario's nuclear capacity falls into this contract, as well as between 40 and 75% of OPG's hydroelectric capacity. The other two types of contracts are Feed-in-Tariffs (FiT and micro-FiT) for production

from renewable sources and financial contracts with the Ontario Electricity Financial Corporation (OEFC). The latter type is quite common in electricity markets and can be described as futures contracts on production. Our methodology assumes that all these contracts have the same properties as vertical contracts as described in Bushnell et al. [2008]. In total, these contracts fix the price for approximately 90% of Ontario's total production. Although the fraction of load that is actually traded through the spot market may seem small, this has important consequences for the rest of the market and it is a common feature in other electricity markets.[7]

The IESO licenses more than a hundred electricity producers in Ontario. These companies can be separated in the same way as in Bushnell et al. [2008], by identifying the main firms (or dominant players) and small firms which act as price-takers in the market. Following Genc [2014] we identify three main players in the Ontario market: OPG, Bruce, and Brookfield. These three players hold 80% of the province's total capacity and satisfy, on average, 92% of the hourly demand. All other firms are considered as price-takers. One particularity to notice within the group of dominant firms is that all of them hold regulated assets in their portfolio. Bruce even has its whole production guaranteed under contracts with the OEB.

Finally, the supply side is also characterized by the Ontario's connections with other Canadian provinces and U.S. states. In fact, Ontario's electricity grid is connected to five other regions: Quebec to the east, Manitoba to the west, New York to the southeast and Michigan and Minnesota to the southwest. This pool of suppliers allows the province to manage its market with great flexibility: the IESO constantly negotiates for imports (exports) from (to) these states. Modeling of these exchanges is nicely documented in the literature evoked above. Our paper follows the estimation methodology from Bushnell et al. [2008] for the net exports supply.

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[7]See for instance Potomac Economics [2008].

3 Data

The data come from three main sources: market equilibrium data provided by the IESO, meteorological data from the NOAA and production data from the IESO, individual firms' financial statements and cost reports.

3.1 Market equilibrium data

Our dataset is in the form of hourly variables spanning from May 1st, 2010 to December 31st, 2012. The variables extracted from the IESO datasets are the total load, total quantity demanded in Ontario, net exports from each connected region, market prices and available capacity for each generating unit.[8] A summary of the data is provided in Table 1.

Table 1: Descriptive summary statistics of market equilibrium data in Ontario, from May 1st, 2010 to December 31st, 2012

| Year | Avg. hourly demand* | Avg. market price† | Avg. hourly net exports, by region* | | | | | |
			MB	MI	MN	NY	QC	Total
2010	17,960	37.83	−70	241	10	282	809	1,272
2011	17,616	30.13	−63	441	15	520	233	1,146
2012	17,749	22.82	−26	766	16	658	−203	1,211

*: in MWh; †: in CAD/MWh

3.2 Meteorological data

Meteorological data are needed to estimate the net exports supply function for Ontario. From the methodology described in Bushnell et al. [2008], net exports are linked to two types of variables: prices in Ontario and weather conditions (both local and outside the province). NOAA provides hourly temperatures for many major cities in North America.[9] In order to compute the average temperature of each region, we take the population-weighted average

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[8]Data was obtained openly through the IESO website. The Generator Output and Capability datasets give generator-level capacities, the Inertie Flows datasets provide information on trade flows and finally, the Ontario and Market Demand datasets provide demand data. For more information: http://www.ieso.ca/Power-Data/Data-Directory

[9]Data was obtained openly through the National Centers for Environmental Information (NCEI) website. The Climatic Data OnLine (CDO) provides a complete dataset of hourly observations for temperature in most North American cities. For more information: https://www.ncdc.noaa.gov/cdohtml/info.html

over at least 5 major cities in the specified region. Then, we compute the variables Cooling Degree Days (CDD) and Heating Degree Days (HDD)[10].

3.3 Electricity generation data

Following the literature mentioned above, in order to find market equilibria, we need to compute cost functions for the market as well as for main players in the industry. Again, the IESO provides a complete, hourly description of electric generation capacity for each different source. However, this capacity is not linked to the asset's specific owner (and even if it was, contracting between firms and regulators would also be needed to assess exact ownership). Therefore, data on asset capacity for the main firms are extracted from financial statements available online (Brookfield Renewable Partners [2012], Bruce Power [2012], Ontario Power Generation [2012]). The capacity for the set of non-dominant players is simply the difference between market capacity and that of the dominant players. We also retrieve from the financial statements the proportion of regulated assets in each firm's portfolio, these data are displayed in Table 5 in the Appendix.

The second piece of information to characterize the cost functions is the marginal cost of production. As we do not observe plant-level data, we assume that each source has a constant marginal cost regardless of the technology and compute an estimate of the marginal cost for each source of production. This general formula for the marginal cost is used across the literature and is defined by, for any source j:

$$\text{MC}_j = \text{Variable O\&M cost}_j + \text{Fuel cost}_j \times \text{Heating rate}_j.$$

Additional data sources and details on the computation of these marginal costs are provided in the Appendix.

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[10]HDD are defined as 0 if the day's mean temperature is greater than 65°F and it is equal to (65°F - day's mean temperature) if the mean is less than 65°F. CDD (cooling degree days) are defined similarly but for temperatures above the day's mean, otherwise it is equal to 0.

4 Competition Models and their Estimation

In this Section we present the theoretical models used to solve for the market equilibria: a perfect competition model and a Cournot duopoly with a non-strategic fringe. Then we explain the relationship between ownership transfers of renewables from non-strategic firms to strategic firms using a stylized model. Finally, we describe the estimation technique for the market demand.

4.1 Competition models

The literature on the particular modeling of electricity markets shows that, under uncertainty, actual market outcomes will lie between Cournot outcomes and perfect competition outcomes (Klemperer and Meyer [1989]). In particular, we should have that $p^{\mathrm{PC}} < p < p^{\mathrm{C}}$ where p stands for the actual market equilibrium price observed in the data and the other two prices represent the perfect equilibrium and the Cournot outcome, respectively. Empirical work such as in Bushnell et al. [2008] has shown that this insight holds in actual markets. In this paper, we show that this finding can be verified in the Ontario electricity generation market as well and use our model to estimate bounds on counterfactual policies. In order to perform such an analysis, we need a model for each strategic setting.

4.1.1 Perfect competition

The perfect competition case is the simplest one: all firms act as price-takers and choose the quantity level from their non-RES capacity to be such that the market price is equal to the marginal cost of electricity generation. In this model, without loss of generality, we merge all firms into one such that there is only one supply curve for the market. Note that this supply function is actually a step function with each step being the total capacity of one generation source, ordered from the lowest to the highest marginal cost. The main difference with the classical optimization problem is that the quantity of renewables is not a decision variable: RES are non-dispatchable.

To solve the model, we write the problem as a mixed complementarity problem (MiCP or MCP) following Ruiz et al. [2014]. Before setting up the model, we introduce the variables.

$\mathcal{J}$ is the set of conventional sources of electricity (non-RES). Renewables will be denoted by the subscript R. Each source has a capacity constraint denoted by $\bar{K}_j$ for conventional sources and $\bar{K}_R$ for renewables. Both constraints represent the available capacity at each point in time. $P(\cdot)$ is the aggregate inverse demand function and $C(\cdot)$ is the aggregate cost function. Finally, we denote quantities by q_j for conventional sources and q_R for renewables, with $q_R = \bar{K}_R$ because of the non-dispatachable properties of RES. The firm's problem is to choose quantities from conventional sources to maximize profits, subject to capacity constraints. Formally, at each period in time, each firm solves:

$$\max_{\{q_j\}_{j\in\mathcal{J}}} P\left(\sum_{j\in\mathcal{J}} q_j + \bar{K}_R\right) \cdot \left(\sum_{j\in\mathcal{J}} q_j + \bar{K}_R\right) - C\left(\sum_{j\in\mathcal{J}} q_j + \bar{K}_R\right)$$

$$\text{s.t. } q_j \leq \bar{K}_j : \mu_j \quad (j \in \mathcal{J})$$

$$0 \leq q_j : \lambda_j \quad (j \in \mathcal{J})$$

where μ_j and λ_j represent the dual variables associated with the constraints. This problem can then be reduced to the following system of equations:

$$C'(Q) - P(Q) + \mu_j - \lambda_j = 0$$

$$0 \leq \bar{K}_j - q_j \perp \mu_j \geq 0$$

$$0 \leq q_j \perp \lambda_j \geq 0$$

where the first equation is the first-order condition derived from the Lagrangian function. The second and third equations are the complementarity conditions derived from the constraints. Note that $\perp$ represents the typical slackness conditions ($q_j \cdot \lambda_j = 0$, $q_j \geq 0$, $\lambda_j \geq 0$). Finally, recall that in the perfect competition setting $P'(Q)$ was cancelled out because of the price-taking assumption. This system is then fed into the PATH solver to get the solution, for each individual period separately. The solver is used through the GAMS API for Python 3.6.

4.1.2 Cournot competition

Here we model the market as a Cournot duopoly with a price-taking fringe. Two firms ($i \in \mathcal{I}$) compete a la Cournot while another agent, the fringe (f), takes the price as given as in the

previous model and produces a quantity Q_f. We therefore have three agents, each optimizing their profit function over the quantities of conventional electricity.[11].

Again, we use the MCP framework to solve the model. The fringe player is modeled exactly as in the previous section and therefore, we omit those equations. A complete characterization of the strategic players' problem is as follows:

$$\max_{\{q_{ij}\}_{j\in\mathcal{J}}} P\left(\sum_{j\in\mathcal{J}}q_{ij} + \bar{K}_{iR} + Q_{-i} + Q_f\right) \cdot \left(\sum_{j\in\mathcal{J}}q_{ij} + \bar{K}_{iR}\right) - C_i\left(\sum_{j\in\mathcal{J}}q_{ij} + \bar{K}_{iR}\right)$$

$$\text{s.t. } q_{ij} \leq \bar{K}_{ij} : \mu_{ij} \quad (j \in \mathcal{J}, i \in \mathcal{I})$$
$$0 \leq q_{ij} : \lambda_{ij} \quad (j \in \mathcal{J}, i \in \mathcal{I}),$$

where Q_{-i} is the sum of the outputs of the strategic firms that are not i. That problem yields the following set of conditions, for each firm and each hour:

$$C_i'(Q) - P'(Q) \cdot \left(\sum_{j\in\mathcal{J}}q_{ij} + \bar{K}_{iR}\right) - P(Q) + \mu_{ij} - \beta_{ij} = 0$$
$$0 \leq \bar{K}_{ij} - q_{ij} \perp \mu_{ij} \geq 0$$
$$0 \leq q_{ij} \perp \lambda_{ij} \geq 0.$$

Altogether with the fringe conditions, we obtain a "square" system of equal number of equations and unknowns.

4.2 Ownership transfers

We begin with a stylized Cournot model inspired by that in Acemoglu et al. [2017] and Brown and Eckert [2018] to show the effect of change of ownership of RES on equilibrium prices.

There are two groups of players in the market: the fringe and the strategic firms. The former does not have any influence on the equilibrium price but the latter does. There is a total capacity of RES in the market of $\bar{K}_R$ and this amount is fixed.[12] The fringe's total

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[11]Recall that the RES we consider here are non-dispatchable and that as mentioned earlier, we are interchangeably using these two terms because the proportion of biomass in the system is negligible.

[12]This is a reasonable assumption for the Ontario market since there is a surplus of total installed capacity. Later in the paper we run counterfactuals where there is a net expansion of the RES capacity in the system.

capacity consists of a fraction $1 - \gamma$ of the total RES capacity plus some thermal capacity $\bar{K}_{f,\text{NR}}$. The strategic firms own the remaining fraction of RES. To simplify the notation we assume that there are n symmetric strategic players in the market, each owning an RES capacity $\bar{K}_{i,\text{R}} = \gamma/n \cdot \bar{K}_{\text{R}}$.

Proposition
With the setting described in the previous paragraph and (i) a demand function $P(\cdot)$ such that $P' < 0$ and $P'' \leq 0$ (ii) a total cost function $TC(\cdot)$ such that it is additively separable in non-renewable $(C(\cdot))$ and renewable inputs $(C_R(\cdot))$ and (iii) $C' > 0$ and $C'' > 0$, then:

- $\frac{\partial q_{i,NR}}{\partial \gamma} < 0$,

- $\frac{\partial q_{f,NR}}{\partial \gamma} > 0$, *and*

- $\frac{\partial P}{\partial \gamma} > 0$.

The proof is in the Appendix. The assumption $P'' < 0$ is only required to guarantee that some differences in the proof can be signed but all that is really needed is that the demand is not too convex. The first result in the Proposition shows that the strategic firms will withhold thermal capacity as the quantity of RES capacity owned by these firms increases. At the same time, the fringe will expand its thermal output as it loses RES capacity from its portfolio. And finally, there is an upward pressure on equilibrium prices from the change in ownership.[13]

The same characterization for the asymmetric case would require specific assumptions on the way the RES and the thermal capacities are split among the firms. This observation naturally motivates the use of an empirical analysis to answer the question of whether prices would increase when there are RES transfers from the fringe to the strategic firms.

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[13]In Acemoglu et al. [2017] there is an amount $(1 - \gamma)\bar{K}_{\text{R}}$ of RES capacity owned by the fringe as well. In their Theorem 1 part 2, their comparative statics show that by increasing γ, prices increase. The authors call this a diversification effect, however the change in prices is not only due to a reshuffling of the capacities of the different technologies in the firm's portfolio, but it requires a physical addition of RES and the market power exercised changes as well. These combination of forces makes it impossible to disentangle a pure diversification effect from the market power effect. This is why we opt to call this a *dilution* effect.

4.3 Demand estimation

Following the literature in electricity market models, we assume that total demand for electricity in Ontario is price-inelastic. To this demand, we add net exports, which we estimate as a function of prices in Ontario as well as meteorological and calendar variables. This yields a price-elastic demand function faced by all the firms. Estimating the net exports supply function is therefore crucial to getting a demand function for our model.

First, we need to choose a functional form for the net exports supply function. Since we observe both positive and negative quantities and positive and negative prices, we cannot use a log-linear form as used in Bushnell et al. [2008] or Brown and Eckert [2016]. Instead, we use a simple linear function. An individual linear net exports supply function is estimated for each region $k \in \mathcal{K}$ connected to the Ontario grid. By separating these regions, we can capture different price elasticities corresponding to different trading behaviors with these regional markets.

Following Bushnell et al. [2008], we estimate the net exports supply function as:

$$Q_{\text{nx},k,t} = \beta_{0,k} + \beta_{1,k} \cdot p_{\text{ON},t} + \beta_{2,k} \cdot \text{CDD}_{\text{k},t} + \beta_{3,k} \cdot \text{HDD}_{\text{k},t} + \beta_{4,k} \cdot \text{Weekday}_t \tag{1}$$
$$+ \sum_{y=2011}^{2012} \psi_{y,k} \cdot \text{Year}_y + \sum_{s \in S} \gamma_{s,k} \cdot \text{Season}_s + \sum_{h \in H} \omega_{h,k} \cdot \text{ToD}_h + \varepsilon_{k,t}$$

where the sets S and H are the sets of seasons and periods of the day, respectively. The variables Weekday, Year, Season, and ToD (the period of the day) are all dummy variables. nx stands for net exports, k indexes the region, $p_{\text{ON},t}$ is the spot price in Ontario at time t, and $\{\beta_{.,.}, \psi_{.,.}, \gamma_{.,.}, \omega_{.,.}\}$ are the parameters to be estimated. The dummy variable for ToD is defined following the IESO classification of hours, as presented in Table 2 below.

Table 2: IESO classification of different period of the day

Name of the period	Associated hours
Night off-peak	8.00 p.m. - 6.00 a.m.
Day peak	6.00 a.m. - 8.00 a.m.
Day off-peak	8.00 a.m. - 5.00 p.m.
Night peak	5.00 p.m. - 8.00 p.m.

The estimation process described above is not complete without the choice of the instruments. In fact, since we are estimating a market equilibrium, it is affected by both supply and demand shocks. In this setting, we are interested in estimating a supply function, meaning we need to find a "demand-shifter"-type of instrument. The literature gives us two possible choices: domestic weather data (Brown and Eckert [2016]) or domestic demand (Bushnell et al. [2008]). These two instruments are valid as they only affect willingness to pay for imports, without having an effect on the connected regions' capacity to produce energy.

Table 3 presents the main results. For our equilibrium analysis we choose to use the regressions from the weather-based instruments since they provide higher R^2 by equation than those obtained from the domestic demand-type instrument. However, we also present those results in Table 7 in the Appendix. The implied inverse demand slopes are -0.0238 and -0.0307, respectively, thus by choosing the former we err on using residual demand functions that are relatively more inelastic but only by a very small amount. Each regression projects net exports through a specific connection line on the market price, weather variables and calendar dummies, as shown in Equation 1.

The last step is to recover the aggregate inverse demand function. First, we write total demand as a function of the price-inelastic Ontario demand, plus net exports:

$$Q = \bar{Q}_{\mathrm{ON}} + \sum_{k \in \mathcal{K}} Q_{\mathrm{nx},k}$$

Note that we chose to remove the time index t for clarity. Then, we substitute $Q_{\mathrm{nx},k}$ for its estimated counterpart, by aggregating all variables except price into a state-observation specific constant $\hat{\alpha}_k$ and using $\hat{\beta}_{1,k}$ (the estimated coefficient on price) as the slope to get:

$$Q = \bar{Q}_{\mathrm{ON}} + \sum_{k \in \mathcal{K}} \left[\hat{\alpha}_k + \hat{\beta}_{1,k} p_{\mathrm{ON}} \right] \Leftrightarrow Q = \bar{Q}_{\mathrm{ON}} + \sum_{k \in \mathcal{K}} \hat{\alpha}_k + \left(\sum_{k \in \mathcal{K}} \hat{\beta}_{1,k} \right) p_{\mathrm{ON}}$$

$$\Leftrightarrow p_{\mathrm{ON}} = \frac{-\bar{Q}_{\mathrm{ON}} - \sum_{k \in \mathcal{K}} \hat{\alpha}_k}{\sum_{k \in \mathcal{K}} \hat{\beta}_{1,k}} + \frac{Q}{\sum_{k \in \mathcal{K}} \hat{\beta}_{1,k}}.$$

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Table 3: Net exports supply function estimation, using weather-type instruments

| | | First stage | | Second stage | | | |
	N	F-stat.	Adj. R^2	Wald-χ^2	R^2	p_{ON}	SE
		Implied inverse demand slope: $\beta = -0.0238$					
MB	23,015	210***	0.216	5,700***	0.162	0.382***	0.088
MI	23,015	221***	0.222	12,906***	0.340	6.683***	0.889
MN	23,015	211***	0.219	3,069***	0.123	0.116*	0.060
NY	23,015	215***	0.216	4,895***	-	-18.537***	0.832
QC1	23,015	269***	0.219	12,956***	0.100	-25.001***	0.730
QC2	23,015	-	-	11,613***	0.298	-3.864***	0.214
QC3	23,015	-	-	3,355***	0.024	-0.429***	0.027
QC4	23,015	-	-	3,856***	0.119	-0.455***	0.039
QC5	23,015	-	-	8,628***	0.234	-0.553***	0.042
QC6	23,015	205***	0.221	2707***	-	-0.219***	0.014
QC7	23,015	-	-	2,619***	0.104	-0.015***	0.009
QC8	23,015	-	-	11,342***	0.320	-0.108***	0.013

*, ** and *** represent significance at the 10%, 5% and 1% confidence levels respectively.

Notes: MB = Manitoba, MI = Michigan, MN = Minnesota, NY = New York, QCx = Quebec connection lines. QC1-QC5 share the same first stage because we use the same regressors across these connection lines. The estimates $\hat{p}$ used in the second stage are therefore the same for QC1-QC5, only the net exports are changing, hence the different second stage results for each line. The same applies to QC6-QC8, but the first-stage includes additional month fixed effects than QC1-QC5 to allow for a more flexible function.

5 Baseline Results

Next we assess the performance of our model by comparing simulated prices against the data. Figure 1 shows the time series for the perfect competition and the Cournot simulated prices and the actual prices for the first 240 hours in our dataset. As expected, our model bounds actual prices most of the time.[14] Figure 9 in the Appendix plots the histograms of predicted and actual prices confirming that observed prices lie between our two competition models. The correlation is also well captured by both competition models. Even though it is clear that our simulated prices are not reliable to forecast single points of the price time series, our model captures two of the most important features in the data: their cyclicality and the responses to demand shocks. Moreover, it has been documented that forecasting prices

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[14]Table 6 in the Appendix shows the frequencies of times when the simulated prices bound the observed prices.

in the IESO is a difficult task, see for instance Rodriguez and Anders [2004] and Zareipour et al. [2006] for attempts using machine learning methods. We do not make use of such methods since we are interested in the mechanism of action of the ownership transfers: our model gives a causal interpretation to the parameters in the model which allows us to run counterfactuals.

Figure 1: Simulated vs actual prices
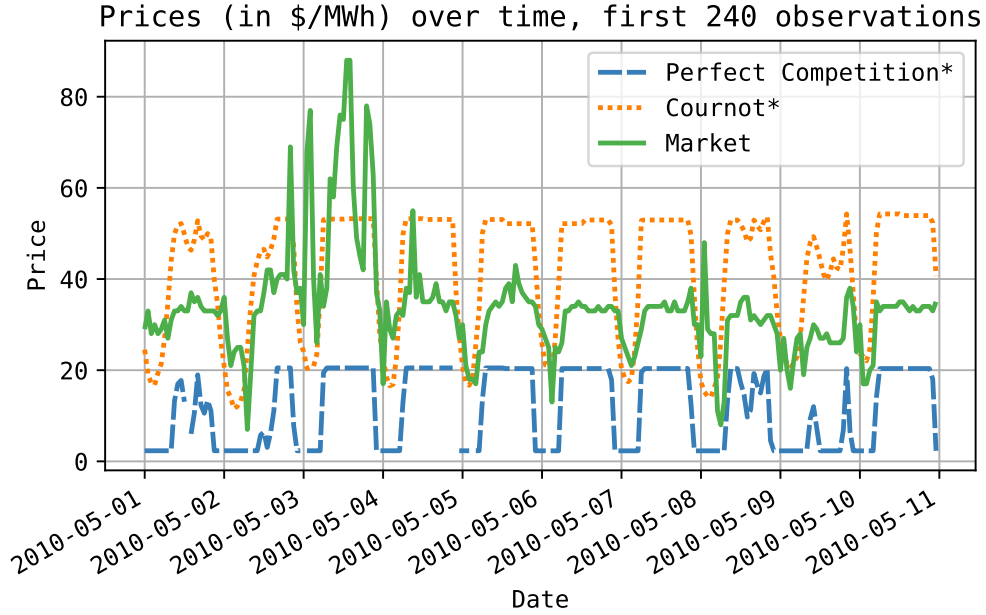
Figure 2 shows the kernel regression of simulated prices on demand intensity. Actual prices are bounded by the perfect competition and the Cournot simulated prices more frequently when demand intensity is roughly between 0.6 and 0.8. Outside that interval, actual prices tend to be higher than our Cournot predictions. The cloud of observed prices indicates however, that most of the observations lie in the interval where our predicted prices bound the market prices. In the Appendix, Figure 10 shows a similar kernel regression but using the demand density conditional on each combination of year-season-peak type. There, actual prices are farther from the Cournot outcomes even at high levels of demand intensity. This observation shows that firms' behavior is more closely represented by a Cournot model when there is high demand, not when demand is only relatively high.

There are two potential explanations for the lack of further accuracy in our simulated

Figure 2: Kernel regression on demand intensity

Kernel regression of prices against demand intensity, based on global maximum
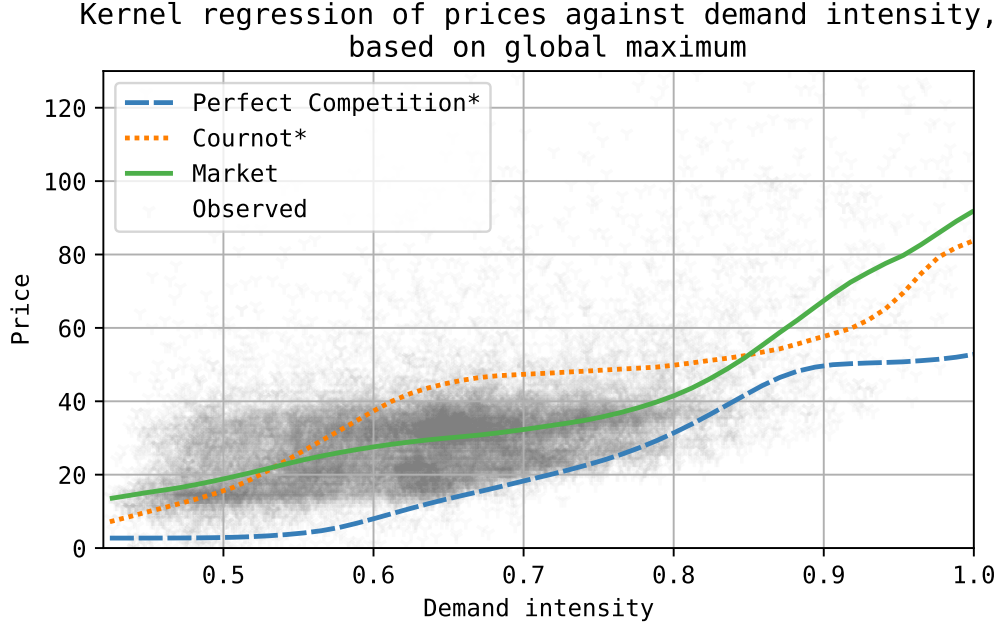
prices. First, it is possible that our marginal costs contain measurement error because we are imputing fuel prices from databases that may not reflect accurately the prices faced by the firms. Second, it is possible that firms are not fully using their market power. Hortaçsu et al. [2017] document how not all electricity generator companies in ERCOT bid at the optimal levels. Rather, there is a bell-shaped distribution of the levels of sophistication of firms on the way they bid. Not all bid at the profit maximizing levels.

In summary, we have a model that allows us to bound actual prices with a degree of accuracy: the Cournot simulated prices are the upper bound and the perfect competition simulated prices the lower bound. In addition, our model allows us to examine changes in the market structure. As usual, there is a trade-off between goodness-of-fit and the capacity to be able to change our model to reflect changes in the firms' environment. In our series of counterfactuals we simulate both types of prices to conclude that the true outcomes will most likely lie in between those bounds. In some counterfactuals we concentrate on the upper bound only since the perfect competition environment is equivalent to assigning the RES to the fringe.

6   The Effects of RES Ownership Transfers

In this section we evaluate the dilution effect on prices. To do so, we simulate transfers of ownership of RES from non-strategic firms (the fringe) into the two strategic firms' portfolios. There are different ways to simulate such scenarios. The underlying idea is that there is uncertainty on the long term existence of FiTs and larger producers can absorb this uncertainty with a more diluted portfolio than the small producers. One possibility is that payments stop to exist and that idle capacity gets transferred to the strategic players either as a policy program or through a sale of assets.

For each time observation, we take a uniform random draw in $[0, 1]$ that represents the fraction of capacity to transfer from the fringe into the two strategic firms. Then, this capacity is split evenly among the two firms.[15] Each time observation is a different combination of state variables and outcomes, by using a uniform random distribution over these observations we attempt to cover as many cases as possible of combinations of factors that affect the outcomes of our policy experiments.

Even though our equilibrium model takes into account the different states of nature when predicting demand, we present our results segmented by clusters. This step does not change the estimation method, it is simply a way to present the results. We use the k-means clustering algorithm, which is a type of machine learning algorithm, specifically from the unsupervised learning methods set (see Hastie et al. [2009]). We define an observation as the vector of the 24 demand observations in one day plus an entry equal to the maximum of those 24 numbers.[16] We use different seeds to check for the robustness of the clustering to initial conditions and we settle at four clusters since this is enough to facilitate the visualization of our results. Figure 8 in the Appendix shows that our choice of four clusters does a good job for most hours of the day at separating our sample into non-overlapping distributions of hourly load when comparing the mass of the distribution within one standard deviation from the mean.

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[15]This limits the exercise of market power over the RES capacity since the two strategic firms are not of equal size. However, we do not want to impose further assumptions on how this capacity is allocated. Later in the paper we present counterfactuals where only one of the firms receives the extra RES capacity.

[16]Callaway et al. [2018] use this technique to split their data.

Figure 3 presents the results from this policy experiment by looking at the mean effect on prices (counterfactual minus baseline) by quantile of the distribution of ownership transfers for each of the data points. The price differences are obtained using the prices from the new equilibrium after the ownership transfer and the equilibrium using our model before any ownership transfers. The figure shows the results by cluster. The impact on prices is positive or zero for all percentages of ownership transferred which means that counterfactual prices are *higher* than the ones in the initial equilibrium. These price changes are more pronounced as the amount of RES transferred is larger. This can seem at first in contradiction with the merit order effect of suppressing prices, however no additional RES have been added to the system since there has only been a transfer of RES from one type of owner to another. Therefore, the supply curve has not been shifted to the right but upwards due to the exercise of market power over the RES that before was owned by the fringe. Figure 3 also shows that prices almost monotonically increase with the quantile of ownership change for all demand clusters.

Interestingly, for the highest demand levels (cluster 1), price changes are the smallest. The opposite occurs with the cluster of the lowest demand levels (cluster 3). This phenomenon shows that when the individual marginal cost function gets shifted to the right, its intersection with a high demand curve still occurs at a point not too far from the profitable price level. However, when the new marginal cost curve intersects a low demand curve, it is possible that the new intersection occurs at a very low marginal cost and the firm internalizes this by exercising a significant amount of market power.

6.1 The effects from dilution

Next, we look into the price effects as a function of the dilution degree of the firm's portfolio. We choose to measure the degree of the portfolio composition by using the Herfindahl index (HHI), which is defined as the sum of the squares of the shares of each of the different technologies in the portfolio. The higher the HHI, the less diversified the portfolio. By construction, the HHI is bounded between 0 and 1. During our sample period, the portfolio diversifications are as in the first line of Table 4. Notice that Brookfield does not have a very

Figure 3: Price differences by quantiles of ownership changes

Average price change for each RES transfer quantile
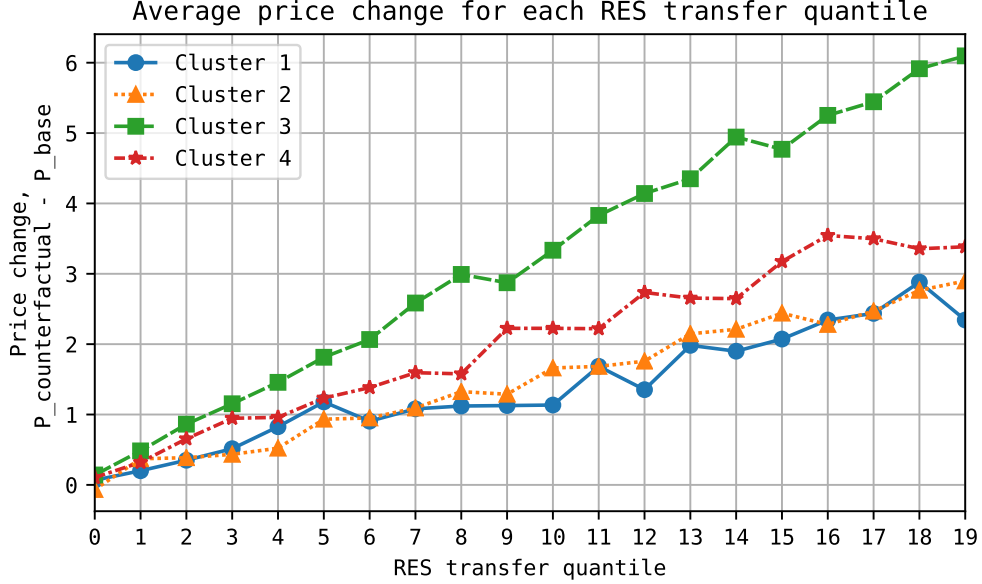
diversified portfolio.

Figure 4 and Figure 5 show the price differences (counterfactual minus baseline) relative to the change in the firm's portfolio HHI, which we define as $HHI_{\text{counterfactual}} - HHI_{\text{baseline}}$. Notice that this difference in diversification is negative because by adding RES into the firms' portfolios, $HHI_{\text{counterfactual}}$ decreases relative to the initial amount of concentration. For those random draws close to zero, the amount of RES transfer is negligible, and therefore, the HHI does not change, which in turn implies that counterfactual prices should be almost identical to the actual prices. This can be seen at the right of the two figures. Then, as the amount of RES increases, the difference in HHI becomes more negative (a lower quantile in the distribution of HHI changes) and this is associated with higher equilibrium prices for all the clusters and for both firms. This is a direct confirmation that even though the firms are

Table 4: Average portfolio concentrations in Ontario

	Market	Fringe	OPG	Brookfield
HHI before adding RES	0.2661	0.3655	0.3529	0.9033
HHI after adding RES	0.2471	0.3294	0.2817	0.5431
Total Capacity (MW)	28,432	19,414	9,462	758

receiving a low marginal cost production technology, they internalize the shift to the right of the supply curve by withholding capacity from the thermal sources to counteract the MoE. Notice also that similarly to the results on the amount of ownership transfers, the cluster that contains the highest (lowest) demand levels is the least (most) affected.

Figure 4: Quantiles of price differences and HHI: OPG
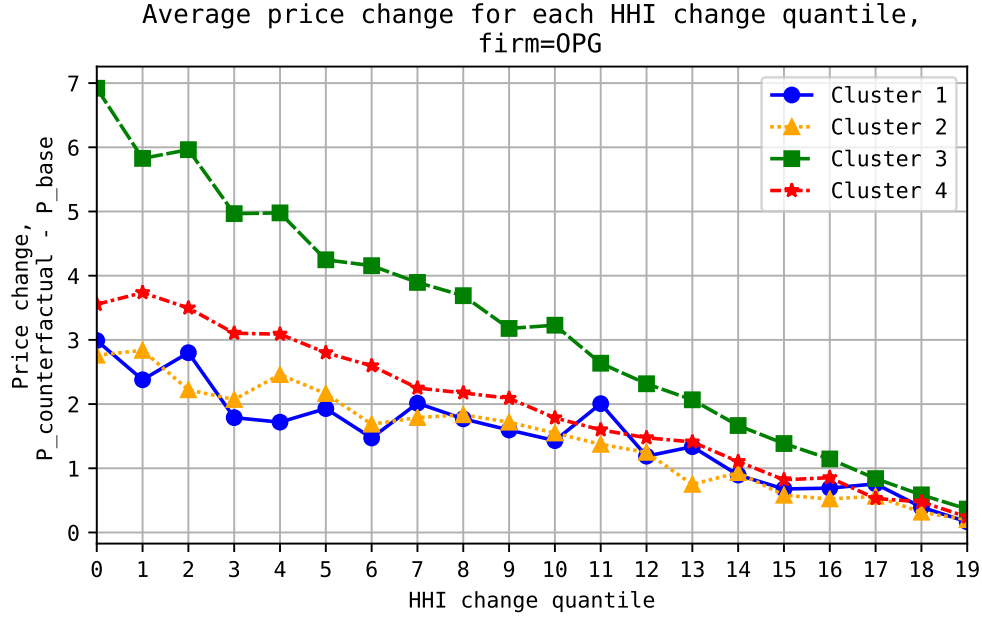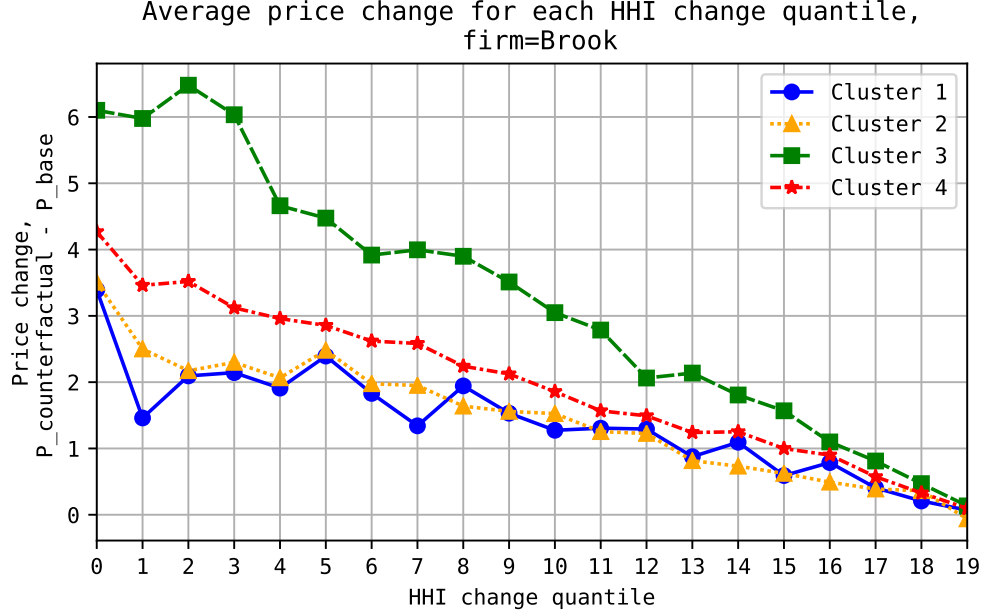

6.2 The effects from a net expansion in RES

Despite the fact that the Ontario system has an excess of capacity installed relative to average load, the IESO projects an addition of 5,000 MW of wind capacity into the system by the end of 2022.[17] Inspired by this projection, we run a series of counterfactuals in which we add that same amount of wind capacity to the system taking into account that demand grows at an annual rate of 1%.[18] Therefore demand is blown up by the factor $1.01^{(2022-2012)}$. Following studies of the Ontario market, we use a capacity factor for wind of 30%.[19] We leave the rest of the capacity fixed at the 2012 levels. This is plausible since during that period of time,

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[17]IESO [2017].

[18]Government of Canada https://www.nrcan.gc.ca/energy/electricity-infrastructure/about-electricity/7359

[19]See https://canwea.ca/wind-integration-study/key-findings/ and https://www.ospe.on.ca/public/documents/presentations/wind-and-electrical-grid.pdf

Figure 5: Quantiles of price differences and HHI: Brook

Average price change for each HHI change quantile, firm=Brook

the system went through a coal phase-out program that ended in 2014 and a few additions of other thermal capacity.[20]

The expansion of RES requires an increase of the thermal capacity to comply with the IESO reliability requirements.[21] These requirements are largely based on those established by the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC). According to the IESO, this requirement translates into operating reserves equivalent to the system's one and a half largest generation units. Notice that this requirement does not take into account the intermittency from RES and therefore, the operating reserves do not change with this increase in wind capacity.[22] In our data, the average proportion of unused capacity in the system is 37% which is significantly larger than the 28% that corresponds to the capacity of the largest and half of the capacity of the second largest

[20]Notice that Genc and Reynolds [2019] also add new RES capacity into the system.
[21]See http://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Operating-Reserve-Markets
[22]Gowrisankaran et al. [2016] find that when solving for the optimal amount of operating reserves in a social planner problem, that amount is 30.5% on average over the different hours of the time period studied in the no RES penetration scenario and up to 35.2% when there is a 20% increase in solar capacity, whereas the implied NERC requirement was of 23% of total capacity only.

plant when added together. Moreover, note that this figure corresponds to whole plants and not generators, as indicated in the guidelines. Therefore, not allowing for an expansion in the system's thermal capacity is a reasonable assumption.

We implement three different scenarios: all new RES capacity is owned by the fringe, by OPG or by Brookfield. The HHI change as shown in the second line of Table 4. For each of the scenarios we solve for the Cournot equilibrium prices at each hour. Figure 6 shows the equilibrium prices predicted by our model in each of those scenarios altogether with the simulated prices when there is no expansion in RES for comparison for the first few hours of our sample. When the additional capacity is owned by the fringe, no market power is exercised over that capacity but the overall system supply curve shifts to the right which tends to lower prices. This is exactly what we see in that graph relative to the prices when either OPG or Brookfield own the additional capacity.
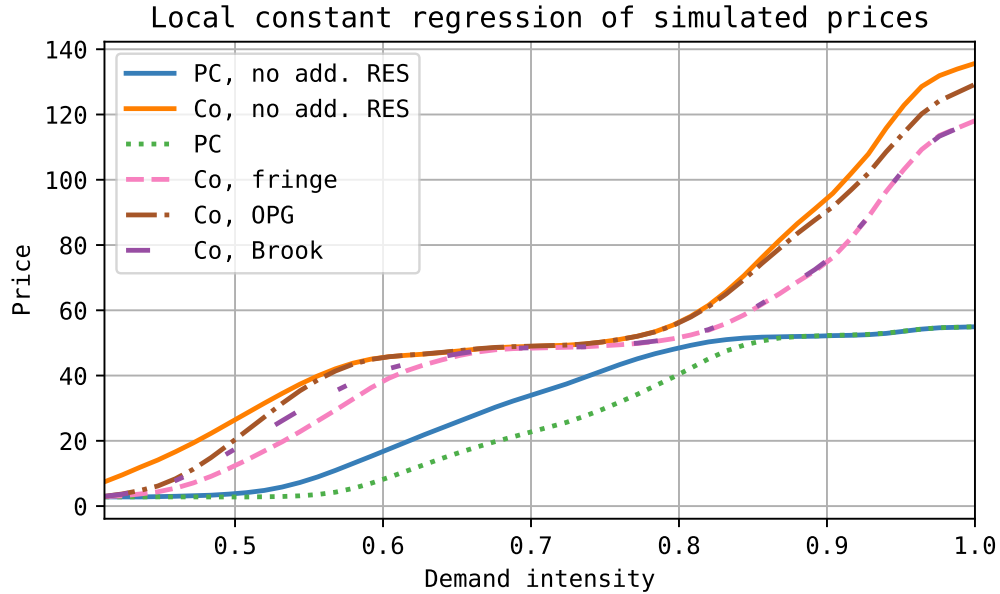
Figure 6: Counterfactual results, first 120 observations (5 days)
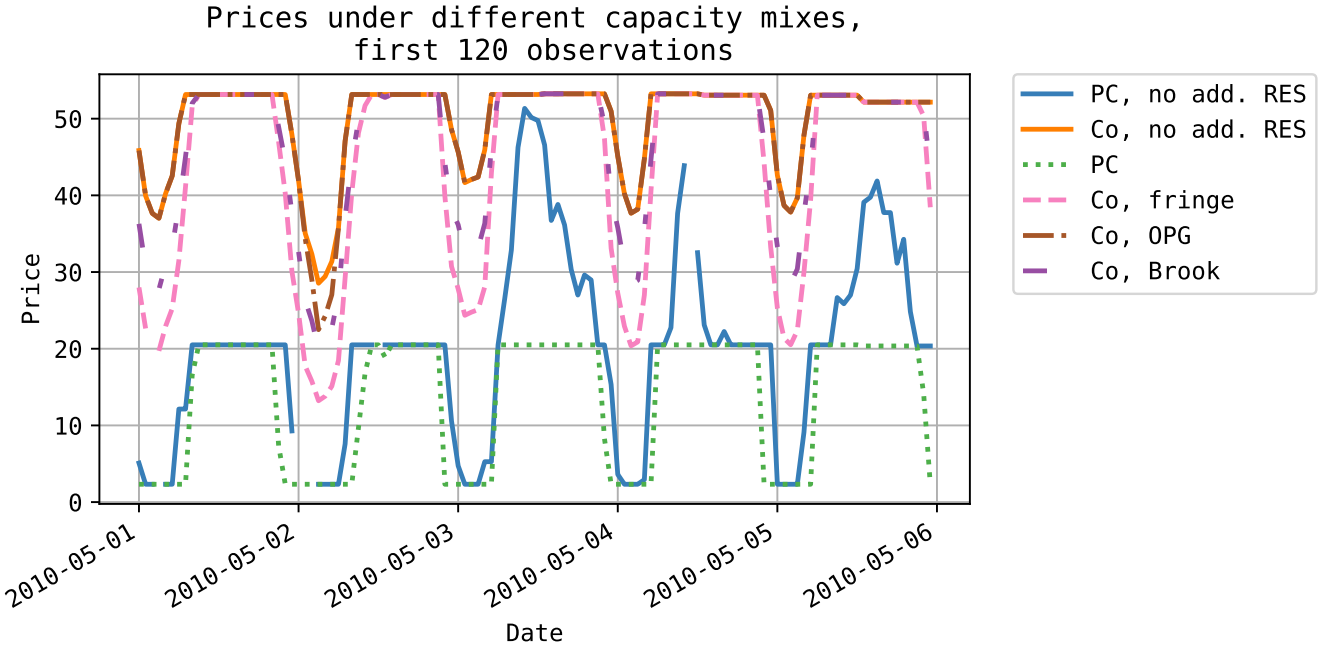
Notes: Co = Cournot, PC = perfect competition, Brook = Brookfield. The "no add. RES" are scenarios where only demand was increased but there is no additions of RES. All other cases include both an increase in demand and an increase in RES capacity. Gaps in the time series represent points where the solver did not find a solution.

The net effect of prices depends on the trade-off between the dilution effect from adding RES to the firm's portfolio (upward pressure on prices) and the merit order effect (downward pressure). Figure 7 shows the kernel regressions of simulated prices from each scenario on demand intensity. The highest prices are still those for the Cournot scenario with no RES added, this is the upper bound. When all the additional RES capacity is owned by OPG, the dilution effect dominates and prices are very close to the upper bound. Recall that OPG is the largest firm. Then if all the additional RES capacity is owned by the second largest firm, Brookfield, market power only has a noticeable effect for demand intensity levels between 0.5 and 0.8, otherwise it has very similar effects as when giving all the extra RES capacity to the fringe.

Figure 7: Local constant regression of counterfactual results

Notes: Co = Cournot, PC = perfect competition, Brook = Brookfield. The "no add. RES" are scenarios where only demand was increased but there is no additions of RES. All other cases include both an increase in demand and an increase in RES capacity. Gaps in the time series represent points where the solver did not find a solution.

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7 Conclusion

In this paper we shed light on the still unexplored consequences of RES additions to the electricity producers' generation portfolios and their interaction with the nature of the ownership of RES capacity. We concentrate on two opposing effects: portfolio dilution and the merit-of-order effect. We find theoretically and empirically that the former puts upward pressure on prices, holding everything else constant. That effect counteracts the widely studied merit-of-order effect. Throughout our series of counterfactuals we show that (i) prices increase when transferring RES capacity from small producers to large producers, (ii) these price increases are larger when the portfolio mix turns more diversified after the transfer which in turn is due to the change of ownership from the fringe to the strategic firms, and (iii) a net expansion of the RES capacity lowers prices by amounts that depend on the size of the firm that acquires the new capacity and by whether the entity can exercise market power or not.

Our results contribute to the long standing debate on the advantages and disadvantages of RES additions in electricity markets. From the economics perspective our paper confirms and quantifies some theoretical results on the interaction of portfolio dilution and market power. From the regulatory and policy analysis perspective, our results suggest a careful analysis on the transfer of RES capacities among market participants and on the nature of the ownership of RES.

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Appendix

Proofs

Proof of the Proposition.

Proof. Profits for the typical strategic firm i are

$$\pi_i = (q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})P(Q) - C(q_{i,\mathrm{NR}}) - C_R(q_{i,\mathrm{R}})$$

where $Q = q_{i,\mathrm{NR}} + q_{i,\mathrm{R}} + Q_{-i} + Q_f$ and Q_{-i} is total output from other strategic firms. The first order condition of the unconstrained problem is:

$$(q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})P'(Q) + P(Q) - C'(q_{i,\mathrm{NR}}) = 0$$

from which we can differentiate with respect to γ:

$$(q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})P''(Q)\frac{\partial Q}{\partial \gamma} + P'(Q)\frac{\partial(q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})}{\partial \gamma} + P'(Q)\frac{\partial Q}{\partial \gamma} - C''(q_{i,\mathrm{NR}})\frac{\partial q_{i,\mathrm{NR}}}{\partial \gamma} = 0. \quad (2)$$

Observe that by using symmetry of strategic firms, the non-dispatchable properties of RES $(q_{i,\mathrm{R}} = \bar{K}_{i,\mathrm{R}} = \frac{\gamma \bar{K}_{\mathrm{R}}}{n})$ and $Q_f = (1 - \gamma)\bar{K}_{\mathrm{R}} + q_{f,\mathrm{NR}}$, where $q_{f,\mathrm{NR}}$ is the output from non-RES in the perfectly competitive fringe, we obtain:

$$\frac{\partial Q}{\partial \gamma} = n\frac{\partial q_{i,\mathrm{NR}}}{\partial \gamma} + \frac{\partial q_{f,\mathrm{NR}}}{\partial \gamma}. \quad (3)$$

If we substitute this expression into Equation 2 we get:

$$\left[(q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})P''n + P' + P'n - C''\right]\frac{\partial q_{i,\mathrm{NR}}}{\partial \gamma} + \left[(q_{i,\mathrm{NR}} + q_{i,\mathrm{R}})P'' + P'\right]\frac{\partial q_{f,\mathrm{NR}}}{\partial \gamma} = -P'\frac{\bar{K}_{\mathrm{R}}}{n}. \quad (4)$$

At the same time, the fringe takes the market price as given and solves the equation

$$P(Q) = C'(q_{f,\mathrm{NR}}).$$

By differentiating with respect to γ we obtain

$$\frac{\partial q_{f,\mathrm{NR}}}{\partial \gamma} = \frac{P'n}{C'' - P'}\frac{\partial q_{i,\mathrm{NR}}}{\partial \gamma} \quad (5)$$

and by substituting this into Equation 4 we obtain:

$$\left[(n+1)P' + (q_{i,\text{NR}} + \frac{\gamma \bar{K}_{\text{R}}}{n})nP'' - C'' + (P' + P'')\frac{P'n}{C'' - P'}\right]\frac{\partial q_{i,\text{NR}}}{\partial \gamma} = -P'\frac{\bar{K}_{\text{R}}}{n}$$

$$\iff \left[P' - C'' + (P' + P'' \cdot (q_{i,\text{NR}} + \frac{\gamma \bar{K}_{\text{R}}}{n}))n\frac{C''}{C'' - P'}\right]\frac{\partial q_{i,\text{NR}}}{\partial \gamma} = -P'\frac{\bar{K}_{\text{R}}}{n},$$

which implies that $\frac{\partial q_{i,\text{NR}}}{\partial \gamma} < 0$ since $P' < 0, P'' < 0$, and $C'' > 0$. As a consequence, $\frac{\partial q_{f,\text{NR}}}{\partial \gamma} > 0$.

Now, we substitute Equation 5 into Equation 3 to get

$$\begin{aligned}
\frac{\partial Q}{\partial \gamma} &= n\frac{\partial q_{i,\text{NR}}}{\partial \gamma} + \frac{\partial q_{f,\text{NR}}}{\partial \gamma} \\
&= n\Big(1 + \frac{P'}{C'' - P'}\Big)\frac{\partial q_{i,\text{NR}}}{\partial \gamma} \\
&= n\Big(\frac{C''}{C'' - P'}\Big)\frac{\partial q_{i,\text{NR}}}{\partial \gamma} \\
&= n\Big(\frac{1}{1 - P'/C''}\Big)\frac{\partial q_{i,\text{NR}}}{\partial \gamma} \\
&< 0
\end{aligned}$$

since the fraction in parenthesis is between 0 and 1 and $\frac{\partial q_{i,\text{NR}}}{\partial \gamma} < 0$.

Finally, observe that

$$\frac{\partial P}{\partial \gamma} = \frac{\partial P}{\partial Q}\frac{\partial Q}{\partial \gamma} > 0.$$

$\square$

Data sources for marginal costs

Renewable energy sources

Marginal costs for RES, wind and solar sources, are set to 0\$/MWh at all times. This follows an assumption that both the Variable Operations and Management (VO&M) costs and energy costs are zero. However, this assumption may not be ideal, in particular for the case of wind power where sources (Navigant [2015]) indicate a positive VO&M cost. This is an innocuous assumption since regardless of the marginal cost for an RES, we treat as non-dispatchable and therefore, they are put in front of the queue of the merit order. Ex-post profits would change if we assumed positive marginal costs. Thus, our profits can be thought as upper bounds of the true ex-post profits.

Natural gas

We follow the NREL Cost Report published by the private consulting firm Black and Veatch in February 2012 [Black & Veatch Holding Company, 2011]. This report identifies three different technologies for electricity production from natural gas: combustion turbine, combined-cycle and combined-cycle with carbon capture. The VO&M costs for these technologies vary between 3.67 US$/MWh and 29.9 US$/MWh (projected as stable for the 2010-2015 period). Concerning marginal cost, the same report states that between 6,705 Btu and 10,390 Btu are needed to produce 1 kWh of electricity. Using historical data on natural gas futures contracts (daily prices) from the Energy Information Administration (`http://tonto.eia.gov/dnav/ng/hist/rngc1d.htm`), we compute the median energy cost by multiplying the input price and the median conversion rate stated above.

Coal

Using the same methodology as for natural gas, we use estimates from the NREL Report in order to get VO&M costs as well as conversion rates for input transformation into electricity. We use historical data on CME futures from the website Investing.com (`https://ca.investing.com/commodities/coal-cme-futures-historical-data`) to get daily input prices that we multiply by the median conversion rate.

Hydroelectric

Following the NREL Report, we set the total marginal cost of hydropower at its VO&M rate, which is estimated to be 6 US$/MWh. No energy cost is reported in the study, which is not surprising given the nature of hydroelectric generation.

Nuclear

Once more, we use the NREL Report estimates. For nuclear energy, no VO&M is reported, the conversion rate is of 9.72 MBtu/MWh. Then, we compute total marginal cost using yearly uranium prices as reported by the EIA (`https://www.eia.gov/nuclear/data.php`).

USD-CAD exchange rates

Finally, since all prices from our data sources on fuel prices are in U.S. dollars, we convert them to Canadian dollars. We use historical data on weekly exchange rates from the website Investing.com (https://ca.investing.com/currencies/usd-cad-historical-data).
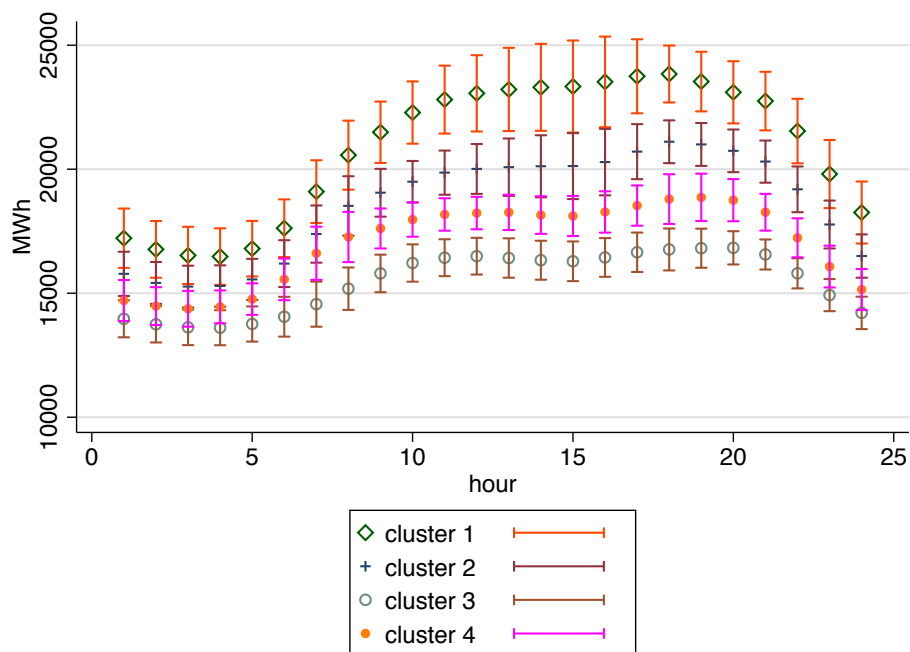
Additional Figures and Tables

Figure 8: Clusters

Figure 9: Distribution of simulated and actual prices
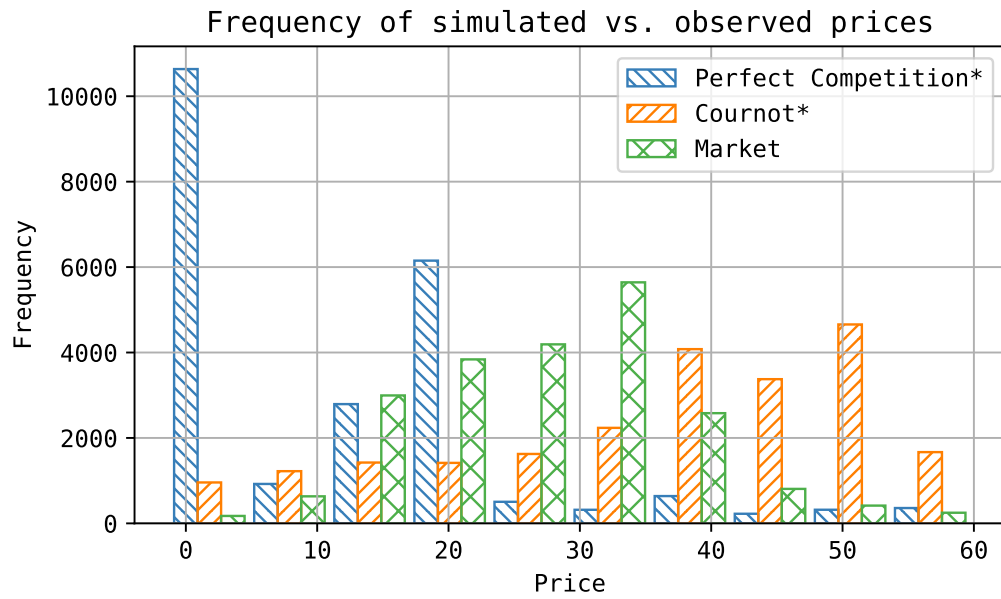
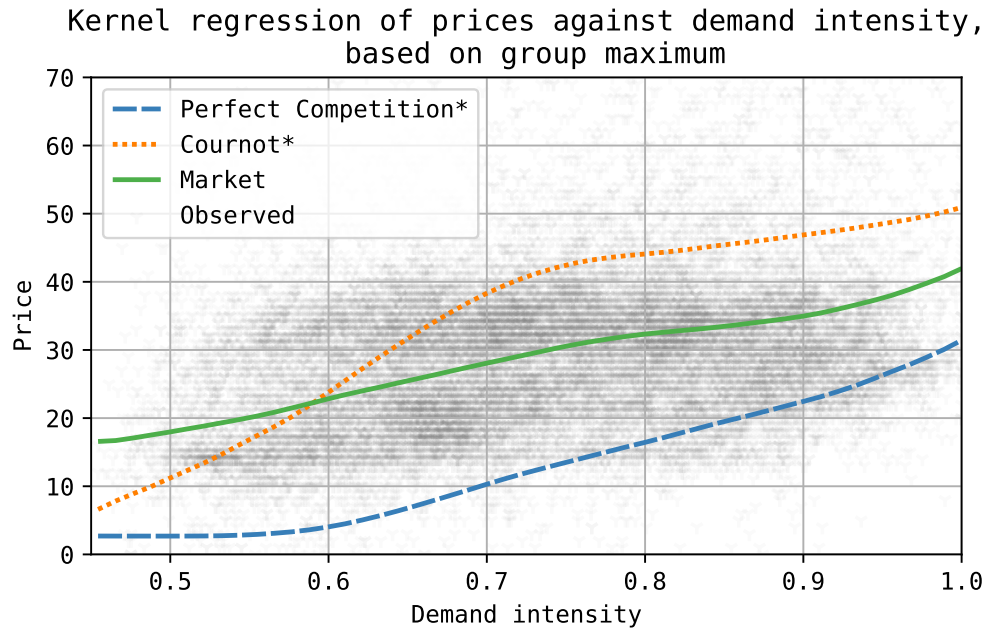Figure 10: Kernel regression on conditional demand intensity

Table 5: Description of the three main firms' energy mix, in MW

Firm	Energy source	2010	2011	2012
OPG				
	Nuclear	6,606	6,606	6,606
	regulated	*6,606*	*6,606*	*6,606*
	Hydropower	6,996	6,996	6,996
	regulated	*3,312*	*3,312*	*3,312*
	Thermal*	5,447	5,447	5,447
	regulated	*0*	*0*	*0*
	Total	19,049	19,049	19,049
	regulated	*9,918*	*9,918*	*9,918*
Brookfield				
	Hydropower	1,369	1,369	1,356
	regulated	*648*	*648*	*642*
	Wind	324	324	326
	regulated	*324*	*324*	*326*
	Natural Gas	36	36	47
	regulated	*0*	*0*	*0*
	Total	1,729	1,729	1,729
	regulated	*972*	*972*	*968*
Bruce				
	Nuclear	6,300	6,300	6,300
	regulated	*6,300*	*6,300*	*6,300*
	Total	6,300	6,300	6,300
	regulated	*6,300*	*6,300*	*6,300*

Notes: * Thermal capacity is not separated between coal and natural gas in OPG's financial statements. However, it is stated in the 2012 report that most of it is coal.

Table 6: Frequencies of observed prices within simulated prices

year	#obs. within bounds	#obs. in year	%
2010	4,117	5,880	70%
2011	5,612	8,471	66%
2012	5,658	8,688	65%

Table 7: Net Exports supply function estimation, using market demand instruments.

		First stage		Second stage			
	N	F-stat.	Adj. R^2	Wald-χ^2	R^2	p_{ON}	SE
MB	23,015	323***	0.289	5,449***	0.087	1.035***	0.063
MI	23,015	348***	0.288	8,099***	-	24.260***	0.717
MN	23,015	329***	0.290	2,821***	-	0.964***	0.044
NY	23,015	341***	0.287	5,625***	-	-18.867***	0.522
QC1	23,015	587***	0.289	12,705***	-	-29.006***	0.545
QC2	23,015	-	-	8,962***	-	-8.934***	0.189
QC3	23,015	-	-	3,521***	0.134	-0.086***	0.018
QC4	23,015	-	-	4101***	-	-0.882***	0.029
QC5	23,015	-	-	8,517***	0.176	-0.757***	0.029
QC6	23,015	402***	0.295	2,904***	0.104	-0.056***	0.009
QC7	23,015	-	-	2,781***	0.027	-0.121***	0.006
QC8	23,015	-	-	11,377***	0.313	-0.122***	0.008

Implied inverse demand slope: $\beta = -0.0307$

*, ** and *** represent significance at the 10%, 5% and 1% confidence levels respectively.

Notes: MB = Manitoba, MI = Michigan, MN = Minnesota, NY = New York, QCx = Quebec connection lines. QC1-QC5 share the same first stage because we use the same regressors across these connection lines. The estimates $\hat{p}$ used in the second stage are therefore the same for QC1-QC5, only the net exports are changing, hence the different second stage results for each line. The same applies to QC6-QC8, but the first-stage includes additional month fixed effects than QC1-QC5 to allow for a more flexible function.

Table 8: Simulation statistics, by year

	Mean price			Median price		
Year	PC*	Mkt	Cou*	PC*	Mkt	Cou*
2010	17.44	37.83	45.70	19.88	35.00	50.96
2011	12.76	30.14	38.06	8.71	32.00	45.09
2012	11.07	22.82	31.47	2.89	22.00	36.64

Notes: * denotes results from simulation. PC = perfect competition. Mkt = actual prices. Cou = Cournot competition.

Table 9: Predicted and actual prices distributions

	Mean	Median	SD	Min	Max	Decile 1	Decile 10
Before period							
PC*	13.28	10.95	12.47	0.00	60.98	2.56	25.30
Mkt	29.34	29.00	20.87	-139.00	558.00	15.00	42.00
Cou*	37.51	40.12	15.75	0.00	106.75	12.63	54.32

Notes: * denotes results from simulation. PC = perfect competition. Mkt = actual prices. Cou = Cournot competition.