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Cleaner but Volatile Energy? The Effect of Coal Plant Retirement on Market Competition in the Wholesale Electricity Market

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Cleaner but Volatile Energy? The Effect of Coal Plant Retirement on Market Competition in the Wholesale Electricity Market

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Abstract

Energy transition from coal to gas is reshaping the power sector to rely more on gas generation, which is cleaner but has more variable input costs. Using counterfactual analysis, I study the competitive effects of this transition, considering several transition paths that differ in the types of firms involved in retiring coal plants and investing in gas plants. I show that the variable nature of the marginal cost of gas generation creates an environment in which market power could increase after the transition. However, the transition's impact on competition depends on the characteristics of the firms investing in new gas generation; the adverse impact is mitigated under a well-planned transition that leads to a more competitive industry structure.

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1 Introduction

The conventional baseload generation using coal and nuclear power is rapidly retiring from the grid, and the cleaner natural gas and renewables are emerging as an energy source replacing the retired generation in the U.S. wholesale electricity market. An important factor responsible for the transition of the grid, besides the environmental regulation, is the increasing economic pressure that coal power plants face from cleaner energy, especially natural gas generation. Due to a significant drop in natural gas prices over the past decade, which lowered the price of natural gas close to coal prices, coal power plants are losing their cost advantage over gas power plants and are being driven out of the market.

Although the retirement of coal power plants draws attention regarding the environmental benefits and grid stability issues, this article focuses on the competitive aspects of the transition. That is, will the changing grid conditions – into a heavily natural gas-concentrated industry – affect the competition between firms in the wholesale electricity market? For a comprehensive analysis of the true cost and benefit of transitioning to cleaner energy, it is important to examine the consequences of the energy transition on market power, accounting for various aspects of the transition that might affect the strategic competition between firms.

In that respect, a specific feature of cleaner energy that is particularly relevant for competition is that cleaner energy tends to have more variable input costs than conventional energy. Unlike coal, the price of which is always low and stable, the price of natural gas is volatile, being subject to shocks resulting from the pipeline congestion caused by cold weather. Therefore, the industry's transition towards natural gas is making the industry more vulnerable to input cost shocks, by replacing consistently low-cost generation with a generation characterized by a more variable marginal cost.

I show that an adverse market power impact of the transition can be of a greater concern, particularly when the input cost of gas generation is higher than normal due to its variable nature. That is, the energy transition from coal to gas, which involves replacing a retired coal plant with a new gas power plant, disturbs the distribution of marginal costs among electricity-generating firms, more so when the gas price rises above the normal level due to its variability. Such a disturbance changes the supply responses of firms, thereby affecting the degree of competition by changing the firms' residual demand. Whether market power increases or decreases due to the transition, and the market conditions under which it occurs more often, is an empirical question.

Another important aspect of the transition, which has implications for competition, is that the structure of the industry– a critical determinant of market power – could change throughout the transition process, depending on how retirement and investment occur (e.g., path of transition). The transition involves firms with diverse characteristics, and depending on which firms install new gas generation capacity to replace the retired generation, and by how much, the production scale and the number of firms in the post-retirement industry may differ from those before the transition. For instance, if the investment happens mainly by a dominant firm, market concentration worsens after transition, whereas the industry becomes more fragmented if fringe suppliers enter with new capacity, replacing the retired generation of large-scale firms. Nevertheless, little attention has been given to the *firms* involved in this transition process and how the characteristics of both firms and the industry are changing as a consequence, which are important determinants of market competition.

Incorporating these aspects of the transition, this article studies the impact of the energy transition from coal to natural gas on market power, with natural gas serving as a cleaner but variable energy source. I carefully examine how strategic interactions between firms change once coal plants retire and are replaced by gas plants, accounting for the variation in the cost of gas generation resulting from volatile gas prices. Additionally, I consider several transition paths that differ in how the retired generation is marginally replaced by the new gas generation and show under which case the market would end up with the most competitive form of the industry. Although the findings suggest that market power would increase after the transition, particularly in situations with higher gas prices, the adverse market impact is largely subdued when accompanied by a change in industry structure achieved through a better-designed transition path. This finding emphasizes the importance of industry structure as a means of addressing the problems that the market may confront from having an industry that is more exposed to variable input costs. It also offers policy suggestions to market regulators on how to properly incentivize the installation of cleaner generation capacities, so as to keep the market competitive.

I study this in the context of the New England wholesale electricity market, one of several U.S. electricity markets that frequently experience surges in natural gas prices. Despite having this problem, several large coal and nuclear plants have retired from the New England grid, mostly to be replaced by gas power plants. I use data on the retirement of baseload power plants in New England, which were planned (and announced) as of 2013 (five plants with a total capacity of 3,700 MW), along with rich data on bidding and generation at the firm-generator-level.

Using a model of quantity competition, I conduct a counterfactual analysis to examine the slightly longer-term impact of the transition and to better disentangle the strategic component influencing changes in market outcomes. The main idea is to construct the counterfactual market environment that would emerge in the near future after all the planned retirements of baseload power plants have occurred, and the installations of new generation capacities replacing them are completed. I only take the final form of the counterfactual industry that would emerge once the retirements and investments occur according to the transition path assumed in the analysis, which allows me to maintain a static equilibrium analysis instead of making the analysis dynamic. All other market conditions, such as the demand and marginal cost of generators (natural gas prices), are held constant at the levels observed before the retirement. Then the impact of the transition can be identified by comparing the static equilibrium of the counterfactual post-retirement environment to that before the retirements. As I construct the counterfactual environment separately for each day within the selected sample from the winters of 2013 and 2014 when daily gas prices were volatile, comparing the equilibrium differences (between the pre- and post-retirement states) across days that differ in gas prices reveals how the impact of the transition changes with the increase in gas prices. To compute the counterfactual equilibrium, I mainly use the Cournot model, which well describes the competition between firms in the wholesale electricity market (Bushnell et al. 2008; Ito and Reguant 2016). However, for estimating parameters used in the counterfactual analysis (e.g., marginal cost), I employ the empirical auction model, which relies on the necessary condition of profit maximization to estimate parameters, using rich bidding data.

From the baseline case analysis, I find that market power – measured by how much the Cournot price departs from the competitive level – increases after the transition, raising the strategic price additionally by about $9.8/MWh, on average. This suggests that in the event of the same degree of gas price shock occurring in the transformed industry, the price of electricity would rise more than before, primarily due to the increased market power. When examining the change in market power across different demand and gas price levels, two main patterns emerge. First, market power increases more in the low-demand (off-peak) sample than in the high-demand (peak) sample. Second, and notably, market power increases more as gas prices are higher above the normal level.

How can we rationalize the findings from the baseline case? Intuitively, the replacement of a coal plant with a gas plant – namely, the transition – is more costly when the marginal cost difference between the coal and gas generation is large, which occurs under high gas prices and during low-demand hours when the coal plant is pivotal. Indeed, I find that the marginal cost of a group of strategic firms increases, on average, especially more under these market conditions, leading them to reduce the quantity supplied. If the decrease in strategic quantity is met by an elastic supply from non-strategic firms, the market price will not increase much. However, the non-strategic supply turns out to be relatively price-inelastic, especially on days with higher gas prices, offering a more favorable environment in which strategic firms can exercise market power and raise the price. Among these strategic firms, the large-scale gas-intensive firms, with a significant share of gas generation and no baseload generation, are those most active in exercising market power more often than before the transition. They become the relatively low-cost suppliers among strategic firms after the competitors' coal plants retire, thereby facing less competitive pressure from other strategic firms. Therefore, the change in the competitive environment due to the transition, as described in the baseline case, gives this type of firm an increased ability to exercise market power by profitably withholding the quantity more than before.

However, the results from the three additional cases – in which the industry structure changes after the transition – demonstrate that a well-planned installation of new gas generation capacity can effectively mitigate the adverse impact of the retirement on market power. For instance, when the retired capacities are replaced entirely by new capacity installed by fringe suppliers, market power even decreases after the transition, leading to an average reduction in price of electricity by \$2.7/MWh. Notably, even without new entry, market power increases by less than in the baseline case if the retired firm – a competitor of the gas-intensive firms – installs new gas generation with 50% larger capacity than the retired plant, resulting in an average price increase of \$6.5/MWh. In both cases, the pattern of market power increasing more with higher gas prices also weakens. The most concerning situation arises when large, gas-intensive incumbent firms expand their capacity by installing new gas generation; market power increases more than in any other case. The findings suggest that new capacity should be installed in such a way that either makes the industry more fragmented or curbs the market power of the type of firms that particularly benefit from changes in the competitive environment – namely, the gas-intensive firms, as identified in the baseline case.

The findings of this article have important policy implications for market regulators preparing for the clean energy transition in the electric power sector. First, the analysis provides new insights into the volatile nature of cleaner energy supply and its implications for market competition. Instead of focusing on the energy transition under ideal (low-cost) conditions, I examine the market consequences of the transition in situations where the supply of natural gas is interrupted, leading to variable gas prices. As the grid moves toward integrating large-scale renewable generation – often subject to supply interruptions due to intermittency – the findings presented may have implications for designing the future grid, making the analysis both timely and policy-relevant. Second, the study underscores the importance of guiding the energy transition along a competitive path, acknowledging that the type of firms involved in the transition process is a critical factor. Based on the findings, it is concerning that, currently, we more often observe new capacity installations by gas-intensive incumbent firms, with limited entry by smaller firms. This pattern highlights the need to carefully examine incentive structures in capacity markets to assess whether they are designed to induce investment by firms that do not reinforce existing dominance throughout the transition.

Literature Review Contributing to several strands of literature, this study first expands upon the extensive body of literature that empirically examines competition in the wholesale electricity market (Borenstein et al. 2002, and others). This literature has shown that various factors can affect competition in this market, including forward contracting (Bushnell et al., 2008), transmission congestion (Borenstein et al. 2000; Ryan 2012), and dynamic costs (Reguant 2014). This article contributes to the literature by examining how the energy transition – involving changes in the generation mix resulting from the retirement and investment of power plants – affects competition and market power in the wholesale electricity market.

This article is also related to studies on power plant closures in electricity markets. For example, Davis and Hausman (2016) examine the market impact of a nuclear power plant closure, and Linn and McCormack (2019) explore the drivers of coal power plant retirements in the U.S. My analysis differs by focusing on the competitive effects of the transition – not only the closures themselves but also the replacement of capacity – taking the coal plant retirements as given rather than modeling their causes.

Although this study does not explicitly focus on renewables, it examines the energy transition to gas, which is relatively cleaner than coal and exhibits a variable nature – a feature shared by renewables. This connection places the article within recent research on market power and competition upon the entry of renewable generation. For example, Genc and Reynolds (2019) demonstrate that the market impact of renewable expansion depends on ownership of low-cost renewable generation, finding smaller price impacts when renewables are owned by large firms. Fabra and Llobet (2022) study competition among renewable generators in auctions where their capacities are private information. Jha and Leslie (2025) show the importance of measuring competition within a dynamic framework in a power grid with a large renewable share, where high market rents reflect start-up costs of conventional generators – costs that a static measure of market power would overstate. Although related in focus, my work places greater emphasis on the energy transition itself, showing that variability in the cost of replacement energy sources can lead to market power, and that transition patterns accounting for heterogeneity in firm characteristics beyond market share are critical to understanding competitive outcomes.

Because this study exploits the volatile nature of natural gas prices, it also relates to research investigating the relationship between market power and gas price variation, such as Kim (2022) and Marks et al. (2017). Lastly, as the retirement of coal plants is partly driven by environmental regulations, this work broadly relates to the literature studying industry responses to environmental regulation and policy (Ryan 2012; Fowlie et al. 2016, and others).

2 Institutional Background

2.1 The retirement of baseload power plants and the energy transition

In the wholesale electricity market, the supply-side firms generate electricity using power plants that fuel on different energy sources: coal, natural gas, oil, nuclear power, and renewables. The coal and nuclear power plants have been considered as the *baseload* generation: the low-cost power plant that starts generating early on to serve the base of the electricity demand.

Over the last several years, the U.S. wholesale electricity market has been experiencing a dramatic increase in the retirement of conventional baseload power plants, particularly coal power plants. On the national level, the coal generation has decreased by almost 15% (about 47 GW in size) between 2011 and 2016 (U.S. Energy Information Administration 2017). Nuclear power plants are also rapidly retiring from the grid; about 25% of nuclear power generation currently operating in the grid announced their plans to retire.[1]

This increase in retirements has expedited the electricity grid's transition towards cleaner energy sources because new generation capacity added to the grid to replace the retired baseloads comes mostly from natural gas and renewable generation. In particular, natural gas, which is relatively cleaner than coal (emitting 50% less carbon dioxides than coal), is the dominant energy source among the newly installed or planned generation capacities and is thus the primary energy source replacing coal, at least until the near future. In 2018 alone, 19.2 GW of gas generation capacities were added to the grid at the national level, whereas wind and solar additions were 6.6 GW and 4.9 GW, respectively.[2]

[1] These nuclear power plants have not renewed the license for operation, indicating that they will stop operation and go out of business. https://www.eia.gov/todayinenergy/detail.php?id=31192

[2] The share of gas generation among the capacity additions is much higher in the Northeast region where the penetration rate of renewables is lower than in the Southern and the Western parts of the U.S. Figure C.4 of the Online Appendix for regional variation in new generation capacity additions.

Plant Name	Capacity (MW)	Fuel type	Date of shutdown
Salem Harbor Station	749	coal/oil	June, 2014
Mount Tom Station	143	coal	Oct. 2014
Vermont Yankee	604	nuclear	Dec., 2014
Brayton Point Station	1,535	coal/oil	May, 2017
Pilgrim Nuclear Station	677	nuclear	May, 2019

Notes: Table shows the retirements of baseload power plants in New England that were announced as of 2013 (*Source*: EIA, ISONE)

Table 1: Major Power Plant Retirements in New England

Broadly two factors are responsible for the ongoing energy transition in the electric power sector. First is the stringent environmental regulations that target highly-polluting coal power plants.[3] A more important factor, however, is the economic pressure that coal generation faces from cleaner energy sources, especially natural gas generation. Due to the shale gas boom, the price of gas has decreased to a level comparable with the price of coal. Once the emissions cost is factored in, the marginal cost of gas generation is close to (or sometimes even lower than) that of coal generation. Because the fixed cost of coal power plants is larger than that of gas power plants, coal generation is no longer more efficient than gas generation, both in terms of the marginal operating cost and fixed (startup) cost. The increased penetration of zero-cost renewable generation also puts competitive pressure on coal generation.[4]

2.2 Baseload power plant retirements in the New England electricity market

The New England wholesale electricity market is one of the regional markets undergoing the energy transition. There are a total of 85 electricity-generating firms of different capacities and fuel technologies, supplying electricity to six states in the Northeast. About one-third of the firms are considered large-scale firms that operate multiple power plants (multi-unit firms), and the rest are fringe suppliers operating either a single power plant or a few power plants of small scales. These firms together operate a total of 305 generating units (i.e., power plants).[5]

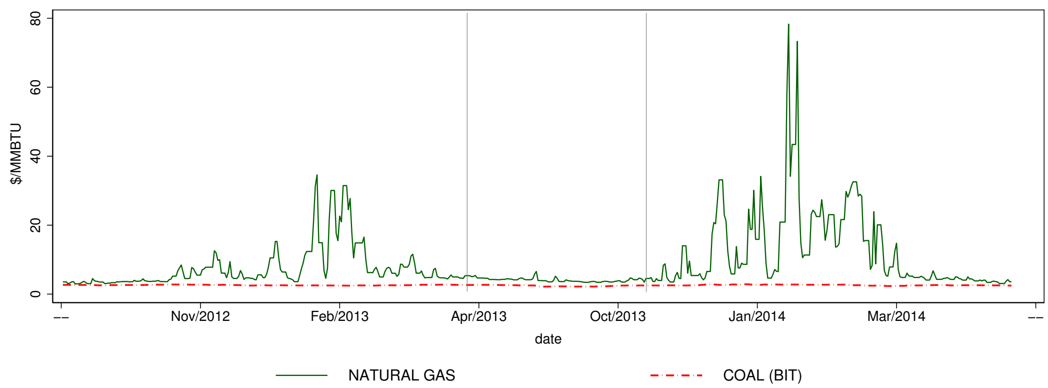
The market had several baseload power plants retired recently, shown in Table 1. More than 3,700 MW of baseload generation – a size equivalent to about 15% of the average daily demand – have retired or are expected to retire by 2020. These retirements will not pose a significant threat to the market operation, as the grid is prepared with enough reserve generation.[6] Nevertheless, in order to guarantee

[3]EPA regulations such as the Mercury and Air Toxics Standards (MATS) and the Cross-state Air Pollution Rule (CSAPR) impose costs on coal plants. Nuclear plants, though emissions free, face stringent and costly safety regulations.

[4]As marginal costs of market-clearing generators have declined, wholesale electricity prices have fallen substantially – even during peak hours. At these lower prices, the revenue earned by baseload generators often fails to cover their large fixed costs (ISO New England 2016).

[5]Table C.5 of the Online Appendix summarizes the capacities of power plants in New England by their fuel type.

[6]Reserve margin in New England was about 70% in 2018-2019 (North American Electric Reliability Corporation 2019).



Notes: Figure shows the spot prices of natural gas (source: *Natural Gas Intelligence*) and spot prices of coal (source: *SNL Energy*) in the New England region from 2012-2014.)

Figure 1: Spot Prices of Natural Gas and Coal in New England

a reliable supply of electricity, more generation capacity would be installed in the longer term to replace the lost capacity from the retired generation. A substantial portion of planned (or approved) capacity additions in the New England grid – especially those installed by major firms, at a large scale – is of natural gas generation. For instance, the total capacity of gas-fired generation approved for installation between 2013 and 2017 is five times larger than that of renewables, as shown in Table C.3 of the Online Appendix.[7]

2.3 Volatile natural gas prices and the marginal cost of generation

An important feature that distinguishes conventional energy sources, such as coal, from cleaner energy sources, such as natural gas and renewables, is the (fuel) price volatility driven by interruptions in energy supply.

The spot prices of coal in the U.S. have historically been low and stable over time. In contrast, natural gas spot prices are subject to upside volatility, meaning that the price does not always stay low as observed during normal periods but can fluctuate between low and high levels. This is because the spot (citygate) price of natural gas, at which local power plants purchase gas, is sensitive to the condition of the pipeline delivering gas to the region. The pipeline often experiences congestion during winter due to increased natural gas demand from the residential heating sector, which increases the total volume of gas flowing through the pipeline. When congestion occurs, spot gas prices (citygate prices) surge above the normal level as a result of this *shock*, with the magnitude of the increase corresponding to the level

[7]A detailed summary of planned capacity additions by fuel type and ownership is provided in Table C.4 in Online Appendix. Further discussion of the characteristics of renewable generation installations is available in Online Appendix C.7.

	Year	Total	\$4 -\$10	\$10-\$20	\$20-\$30	>\$30 (MMBtu)
% (N/365)	2013	28 %	16.2 %	8%	1.6 %	2.2 %
	2014	30.7 %	8 %	8.2 %	10.1 %	4.4 %

Notes: The table reports the percentage (%) of days when gas prices rose above the normal level (shock) in 2013 and 2014. Percentages are calculated based on the total number of days in a year. The last four columns report these percentages separately by the severity of the shock (level of gas price).

Table 2: Summary of Days with Gas Price Shock (New England)

of congestion.[8]

The difference in the price variability between natural gas and coal is depicted in Figure 1, which shows the spot prices of gas and coal in the New England region from 2012 to 2014. Under normal conditions, gas prices are typically low at around \$4/MMBtu, and are comparable to coal prices (as indicated by the plots between the lines). However, gas prices could suddenly increase to a substantially higher level, as shown by the fluctuating price paths. In contrast, coal prices have remained relatively stable over time, exhibiting almost no fluctuations in their price paths.

As fuel costs account for the largest portion of electricity generation costs, the difference in fuel price variability indicates that the marginal cost of gas-fired generation is more prone to fluctuations compared to the relatively stable marginal cost of coal-fired generation. Moreover, unlike coal, which can be stored on-site, natural gas cannot be stored and must be delivered through pipelines at the time of use. The difference in storage options makes the marginal cost of gas generation particularly susceptible to day-to-day variations in spot gas prices.[9]

The variability of gas prices is most severe and frequent in the Northeast, particularly in New England, which suffers the most due to inadequate pipeline capacity.[10] Table 2 shows that nearly 30% of the days in the 2013-2014 sample experienced shocks that substantially raised gas prices in New England, above the normal level of around \$4/MMBtu.[11] Whether these shock events will persist in the future depends on several factors. On one hand, the increased gas demand from the power sector, which be-

[8] This shock affects gas prices for plants buying on the spot market. Plants with long-term gas contracts are less affected, with their gas prices rising less than spot prices. To account for price differences stemming from procurement channels, marginal generation costs are estimated using firm-plant level bidding data (see Section 5.3 for details).

[9] The spot market remains the dominant procurement channel for gas in the power sector. For example, most gas power plants in New England prefer the spot market over long-term contracts (such as *firm* gas pipeline capacity), as it offers greater flexibility in both quantity and price (Northeast Gas Association 2018). In contrast, long-term contracts require plants to commit to fixed quantities over extended periods.

[10] Other parts of the U.S. tend to have larger pipeline capacity, thus less congestion occurring in general. However, due to a constant increase in the use of natural gas over time, the gas prices have reached a record high level in the 2018-2019 winter season, even in Southern California.

[11] The market impact of these abnormal days with high gas prices was rather significant; the increase in wholesale electricity prices caused by the high gas prices was passed onto retail electricity prices, resulting in an average retail price increase of about 20% in the subsequent year (U.S. Energy Information Administration 2018).

comes more reliant on gas-fired generation as baseloads retire, could exacerbate the problem of pipeline congestion. On the other hand, congestion could be alleviated as the pipelines in the Northeast undergo upgrades and expansions.[12]

The issue arising from variable marginal cost is not limited to gas-fired generation; the intermittency of renewable energy also implies that the marginal cost of renewable generation fluctuates. Although the price of renewable energy remains constant, a multi-unit firm that operates renewable generation as part of its strategic assets would experience varying marginal opportunity costs (or expected marginal costs) due to the intermittent nature of their supply. However, the focus of this study is on natural gas, and I do not attempt to draw parallels with renewables in this article. For a more discussion of the common characteristics shared by these energy sources and how this analysis can be extended to renewables, see Online Appendix C.7.

3 The energy transition and the market competition

3.1 Competition in the wholesale electricity market

In the wholesale electricity market, both the supply and demand sides sell and buy electricity in an hourly market organized as auctions.[13] The electricity-generating firms compete by submitting a supply schedule, consisting of price-quantity pairs, that reflects the marginal costs of their power plants and their strategic positions.[14] Among these firms, only the multi-unit firms with considerable production scale are capable of strategically bidding in the auction. Each firm makes a strategic supply decision, considering its own residual demand, which is the market demand net of the supply schedules submitted by other firms, thus making the competition close to an oligopoly. Note that fringe suppliers tend to behave as non-strategic price takers, supplying at their marginal costs.

A unique feature of this market is the (almost) perfectly inelastic demand for electricity from retail companies (e.g., electric utilities).[15] Due to this inelastic demand, strategic interactions between *suppliers*

[12]For instance, four pipelines in the New England area are currently undergoing capacity expansions of 350 MMcf/d, equivalent to 6% of the region's total pipeline capacity as of 2020, with completion expected by 2023 (U.S. Energy Information Administration 2020).

[13]This applies to markets that have undergone restructuring and are operated by independent system operators (ISO). The regional markets in the Northeast (ISO-NE, NYISO), Midwest (PJM, MISO), Texas (ERCOT), and California (CAISO) have undergone restructuring and implemented competitive market mechanisms.

[14]Electricity-generating firms submit a supply curve for each of their generating assets. The supply curve (i.e., price-quantity pairs) specifies the price at which the generating asset (power plant) is willing to supply a specified amount of electricity.

[15]Demand-side firms submit bids without specifying the price they are willing to pay, resulting in an almost perfectly inelastic short-term demand. This is due to the retail companies being obligated by long-term supply contracts with residential customers.

become a more important determinant of market power than the demand itself. In other words, the ability of electricity generating firms to exercise market power, which is governed by the elasticity of their residual demand, primarily depends on how elastic or inelastic the supply from their competitors is.

3.2 The competitive effects of the energy transition

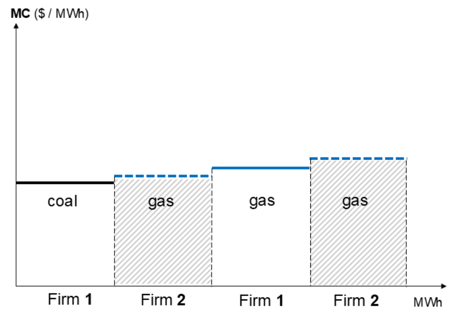
This section describes the basic mechanism and reasoning behind why the energy transition from coal to gas may affect the degree of competition in this market, which motivates the design of the empirical strategy. Note that the discussion in this section serves only to explain why and under which particular conditions competition may be affected by the transition, using a simple example. The extent and direction of changes in competition and market power will be examined in the empirical analysis section, accounting for the actual industry configuration.

3.2.1 Volatile gas price and the impact of the transition in the low-cost and high-cost regimes

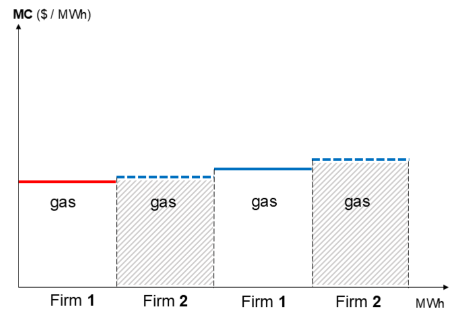
The energy transition involves removing a power plant from an electricity-generating firm's generation mix and replacing it with another plant that uses a different energy source. The market variable directly affected by the replacement of power plants – and relevant to competition – is the distribution of marginal costs across firms; that is, which firms are relatively low-cost or high-cost at a given production level. When the energy transition changes the distribution of marginal costs, it affects firms' strategic supply responses and the degree of competition by changing their residual demand elasticities. Such changes in competition can arise even when the total capacity (or scale) at the firm and industry levels is unaffected by the transition.

This, in turn, implies that the energy transition affects competition only when it results in a considerable change in the marginal cost distribution at the firm and industry levels. Whether this distribution is affected by the transition – and to what extent – depends on the *relative* marginal costs of the retiring power plant and the plant replacing it.

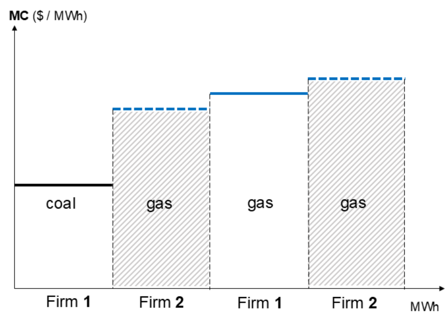
However, relative marginal costs can vary when the replacement plant's marginal cost fluctuates due to the volatile nature of the replacement energy source (e.g., its price or availability). In the case of a coal-to-gas transition, the volatility in gas prices can give rise to two distinct regimes: a *low-cost* regime, where gas prices are within a normal range and close to coal prices, and a *high-cost* regime, where gas prices rise above the normal range. In the low-cost regime, coal and gas power plants have similar



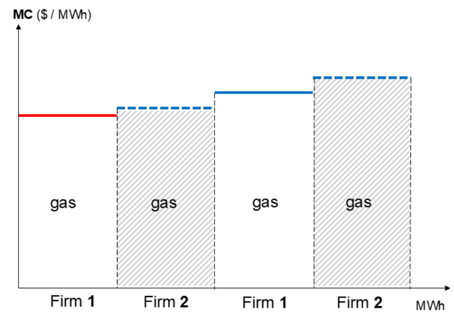
(a) Low-cost regime: before retirement



(b) Low-cost regime: after retirement



(c) High-cost regime: before retirement



(d) High-cost regime: after retirement

Notes: These graphs illustrate a simple example of marginal cost distributions with two firms: Firm 1 and Firm 2. Firm 1 operates the coal plant, whereas Firm 2 does not. Panels (a) and (b) depict the distributions in the low-cost regime (a sample day-hour market without a gas price shock), whereas panels (c) and (d) depict the distributions in the high-cost regime (a sample day with the gas price shock). Panels (a) and (c) display the distribution before the retirement of Firm 1's coal plant, whereas panels (b) and (d) show the distribution after Firm 1 retires its coal plant and replaces it with a equal-sized gas power plant (i.e., Baseline case transition). The marginal cost of a newly installed gas power plant in the post-retirement scenario is represented in red.

Figure 2: Impact of Transition from Coal to Gas on Marginal Cost Distributions: Low-Cost vs. High-Cost Regimes

marginal costs, whereas in the high-cost regime, gas power plants have higher marginal costs than coal plants. Because the relative marginal costs of energy sources differ across these low-cost and high-cost regimes, the impact of the transition on marginal cost distributions would differ across regimes.

I explain why a transition from coal to gas affects marginal cost distributions – and thus competition – more in the *high-cost* regime, using simple plots shown in Figure 2. This emphasis on the high-cost regime motivates the subsequent empirical analysis, which examines how the competitive effects of the transition vary with gas prices.

Figure 2 shows the marginal cost distributions of two firms – Firm 1 and Firm 2 – before and after Firm 1's coal plant is retired and replaced with a gas plant of the same capacity. Panels (a) and (b) depict the pre- and post-transition marginal cost distributions in the low-cost regime, whereas panels (c) and (d) show the corresponding distributions in the high-cost regime. Note that Figure 2 displays only marginal costs – not the supply curve – and is intended to illustrate a reason for the change in competition, not its direction or magnitude.

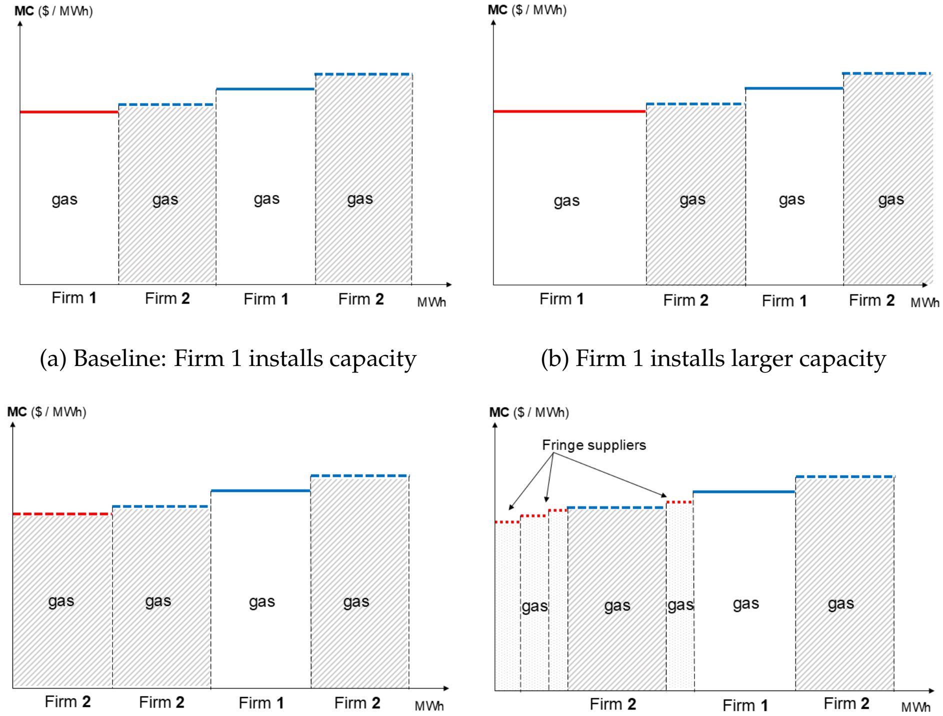
In the low-cost regime, the marginal costs of coal and gas power plants are similar. For instance, when the gas price is at the normal level of $4/MMBtu, the average marginal cost of a gas power plant is about $45.6/MWh, comparable to that of a coal power plant at around $45/MWh. Because these plants have similar marginal costs, transition from coal to gas does not affect the distribution of marginal costs in the low-cost regime. This is evident in panels (a) and (b) of Figure 2, where the marginal cost distributions at both the firm and industry levels are identical. Because there is no change in the marginal cost distribution, firms' strategic production decisions and the overall level of competition would be the same before and after the transition.

However, when gas prices rise above the normal level due to upside volatility – whereas coal prices remain stable – the marginal cost of a gas power plant becomes significantly higher than that of a coal plant. In this high-cost regime, replacing a coal plant with a gas plant changes the marginal cost distribution, with the extent of this change depending on the level of gas prices. This is shown in panels (c) and (d) of Figure 2, where the pre- and post-transition marginal cost distributions differ significantly, implying that firms' strategic decisions and the degree of competition would also differ between the pre- and post-transition periods. Therefore, the transition reshapes competition between firms in the high-cost regime.

Figure B.1 in the Appendix presents an industry-level extension of the comparison shown in Figure 2, using the actual marginal costs of power plants across all firms in the dataset. As shown in the figure, the disruption to the marginal cost distribution caused by the transition is more pronounced in the high-cost regime. When the actual industry configuration is taken into account – comprising a larger number of firms, power plants, and heterogeneous marginal costs – the resulting distributional changes become more complex.

Because high-cost regimes occur less frequently than the low-cost regime, a firm's decision to retire a coal power plant and invest in a gas power plant is primarily based on the relative profitability of these energy sources under normal (low-cost) conditions.[16] However, because high-cost regimes can still arise with some regularity – especially when the replacement energy source is volatile – it is important to understand how competition and market power will be affected by the transition under the high-cost regime.

[16]For example, in New England, gas prices exceeded the normal range on about 30% of days in a year, as summarized in Table 2.



(a) Baseline: Firm 1 installs capacity

(b) Firm 1 installs larger capacity

(c) Firm 2 installs capacity

(d) Fringe suppliers install capacity

Notes: Each panel shows the *post-retirement* marginal cost distribution for the *high-cost* regime. Firm 1's coal plant retired in all cases, but how the new gas generation capacity is installed differs across these panels. The marginal cost of a newly installed gas power plant in the post-retirement scenario is represented in red. Panel (a) is the baseline case, where Firm 1 which previously owned the retired coal plant replaces it with an equal-sized gas plant. Panel (b) shows where Firm 1 installs a new gas plant having a capacity larger than the retired one. In panel (c), Firm 2 installs a gas plant of the same capacity as the retired coal plant of Firm 1. Panel (d) represents the entry of fringe suppliers with capacities matching the size of the retired plant.

Figure 3: Post-Retirement Marginal Cost Distributions: Different Gas Plant Investment Patterns in High-Cost Regime

3.2.2 Installation of new generation capacity and the industry structure

The specific way in which the transition occurs – namely, which firms install new gas generation capacity and the size of that capacity – is another crucial factor affecting competition. The industry's structure, characterized by the number of firms and their production scales, can change significantly throughout the transition, depending on the type of firms involved and how the capacity of new plants compares to that of the retired ones.

For instance, in the earlier example illustrated in Figure 2, I assumed that the same firm operating the retired coal plant (Firm 1) installs a new plant of equal capacity. In this *baseline* case, the transition does not change the industry's structure. However, it is not always the case that the firm retiring its plant installs the replacement capacity. Other incumbent firms, or new fringe entrants, may construct the new gas power plant. Moreover, the new plant may have greater capacity than the retired plant, increasing total capacity at both the firm and industry levels. Given substantial heterogeneity in firms' generation mixes and their potential to exercise market power, the competitive environment of the industry can change significantly depending on which firms expand their scale through new installations.

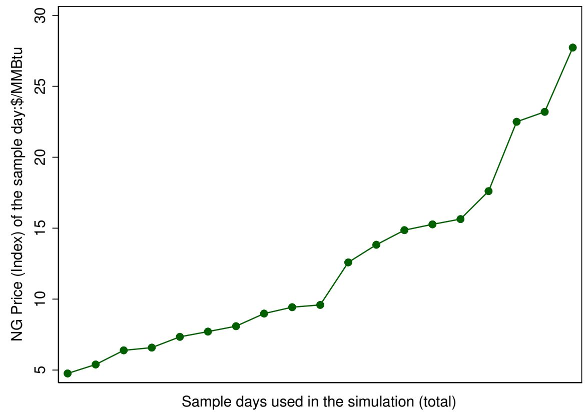
Several illustrative scenarios are shown in Figure 3, which depicts the post-retirement marginal cost distributions in the high-cost regime under different installation patterns. Panel (a) depicts the baseline case (identical to panel (d) in Figure 2), whereas the subsequent panels show the distributions when : Firm 1 installs a plant larger than the retired one (panel (b)); Firm2 – an incumbent that did not own the retired coal plant – installs the new capacity (panel (c)); and fringe suppliers enter with new capacity (panel(d)). Across these panels, we observe changes in firm scale and number, alongside changes in marginal cost distributions. These differences suggest that the competitive effects of the transition vary depending on the pattern of new capacity installation.

4 Empirical Strategy

The empirical strategy is motivated by the insights discussed in Section 3. First, the transition from coal to gas is expected to have a meaningful impact on competition in the high-cost regime. Hence, I restrict our empirical analysis to the higher-gas-price sample and examine how the impact of the retirement-induced transition varies with increasing gas prices. In addition to the variation in gas prices, I also examine how the impact of the transition varies across different industry structures that could emerge under various transition scenarios. Because projecting the long-term trajectory of capacity installation is challenging, I consider several stylized paths of transition.

Counterfactual Analysis To examine the impact of the energy transition on market competition, I conduct a counterfactual analysis based on a structural model that describes quantity competition among electricity-generating firms in the wholesale electricity market. The idea is to construct a counterfactual industry that is likely to emerge in the near future, after all planned retirements of baseload generation have occurred, and new generation capacities replacing the retired ones have been installed. Specifically, I consider only the final industry structure resulting after a series of (planned) retirements and hypothetical investments. Instead of modeling the complete transition process (paths) and endogenizing the investment decisions in a dynamic setting, I compute a *static* equilibrium for a counterfactual industry (i.e., post-retirement) and compare it to the static equilibrium observed in the industry before any retirements occurred (i.e., pre-retirement).

When constructing the counterfactual environment, all other market variables, except for power plant



Notes: The horizontal axis shows the selected sample days aligned in an increasing order of gas price (index data) of the day, shown in the vertical axis.

Figure 4: Gas Price Index Values of the Selected Sample Days

retirements and investments, remain the same as in the pre-retirement sample. Specifically, I construct a counterpart of an actual day-hour market (t, h) from the pre-retirement sample, keeping variables such as electricity demand, fuel spot prices, and the marginal costs of existing power plants at their pre-retirement levels, rather than making arbitrary adjustments within the model. This ensures that the strategic and market environment closely resembles the one observed before the transition, with changes limited to industry components directly related to the transition.

Baseload power plant retirements I use the actual baseload power plants retirements in New England that were announced as of 2013, summarized in Table 1. The list includes five power plants, comprising both coal-fired and nuclear power plants, with a total capacity of 3,700 MW. These plants are operated by four major firms and collectively represent approximately one-fifth of the average daily electricity demand, which is large enough to affect the market outcome.[17] Although the actual timing of these retirements varies, these plants are removed altogether from the firm's generation set when establishing a counterfactual environment.

New gas generation capacity installations Although power plants may retire from operation without immediate replacements in the short term, new generating capacity will be installed in the long run to maintain a reliable grid. In counterfactual scenarios, I make assumptions about the type of firm

[17] I did not allow all existing baseload plants to retire in the counterfactual scenario, as a drastic shift in the generation mix makes it difficult to analyze the underlying drivers of firms' strategic incentives. Moreover, understanding the marginal incentive changes from a partial grid transition is a necessary step toward analyzing a full, long-term transition.

installing the capacity and the size of the capacity.[18]

As discussed in Section 3, the *baseline* case of installation involves the firm that owns a retired baseload power plant, which I denote asthe *retired* firm, replacing it by installing a hypothetical natural gas-fired power plant of the same capacity as the retired one. This scenario serves as a baseline because it keeps the industry structure unchanged, with only the fuel mix of generation assets and the corresponding marginal cost distribution of firms changing as a result.[19] In Section 7, I extend this baseline case by considering various installation patterns. These patterns are designed to provide a better understanding of the factors influencing changes in competition as we vary the industry's structure.

The marginal cost of the hypothetical natural gas power plant is computed using the heat rate of the latest gas generation technology and the daily gas spot price (index). Note that identical marginal cost values were applied to all hypothetical gas power plants, regardless of their owners.[20]

Accounting for the volatile gas price: selection of sample days The pre-retirement sample consists of actual days during the winter seasons between 2012 and 2014 (November - February). This period is chosen because major power plant retirements had not occurred by this point, and, most importantly, because spot gas prices in New England were volatile during this winter period. Figure 4 displays the spot gas prices (price index) of the selected days, which exhibit an increasing pattern across the days.[21] The sample consists of 19 days, each with 19 hourly markets, from 5 AM to 11 PM ($T = 19, H = 19$).[22]

To examine how the transition's impact varies with different gas price levels, I leverage the *observed* cross-day gas price variation in the pre-retirement sample data. I identify the transition's impact for each market (t, h) by comparing the (counterfactual) post-retirement and pre-retirement equilibria, while holding the day's gas price level constant.[23] Holding the gas price level fixed in the counterfactual

[18]Because the new power plant constructions are yet to be completed, with most of them still in the planning stage, there is substantial uncertainty over the type of firms installing the new capacity as well as the size of the capacity.

[19]Although the baseline assumption may appear to be strong, actual capacity installations observed from data (EIA-860) show that many of the retired coal plant sites are, in fact, being converted for the use of gas power generation, making the assumption reasonably realistic. See Section 7 for more details.

[20]I use a uniform heat rate (hr =7MMBtu/MWh) for all hypothetical gas power plants to avoid arbitrarily assigning different marginal costs across owners, which could introduce unintended cost advantages in the replacement process. Although using identical marginal costs regardless of ownership or scale could be problematic if economies of scale were significant, estimated marginal costs for dominant and fringe firms do not differ significantly, suggesting that scale economies are not a major concern here.

[21]The same figure with actual *dates* of the selected days listed in the horizontal axis can be found in Figure C.6 in the Online Appendix. I selected days with similar average daily demand and hourly demand patterns to ensure homogeneity in conditions other than the gas price.

[22]I dropped hours from 12 AM to 4 AM in which the firm's production decision may be influenced more by the fixed cost. More details to follow in Section 5.1 and Appendix A.3.

[23]As more natural gas power plants come online in the counterfactual scenario, increased demand from the power sector may drive gas prices above pre-transition levels. However, the analysis does not account for this endogenous price change.

environment is achieved by using the same daily marginal cost parameters as those estimated from the pre-retirement sample. Then, comparing the identified impacts *across* different days reveals how the transition's impact varies with gas price levels.

Counterfactual equilibrium computation Because firms in the wholesale electricity market compete for production in the multi-unit uniform auction, their behavior is best described by Supply Function Equilibrium (SFE) model. However, conducting a counterfactual analysis within an SFE framework is challenging due to the well-known problem of multiple equilibria, along with the difficulty of characterizing those equilibria. To overcome this challenge, counterfactual analysis in the wholesale electricity market setting relies on computing the Cournot equilibrium, which has been shown in many empirical studies to reasonably approximate the strategic equilibrium (Bushnell et al. 2008; Ito and Reguant 2016; Ryan 2021).[24]

Following the literature, I use a Cournot model to compute the counterfactual strategic equilibrium. Additionally, I compute the counterfactual competitive equilibrium to use as a competitive benchmark for assessing unilateral market power.[25] The difference in equilibrium outcomes between these two market structures reflects changes in firm incentives and market power. I compute Cournot and competitive equilibria for both the pre-retirement and post-retirement samples to ensure consistency in competition forms when comparing outcomes across samples.[26] The impact of the retirement-induced transition is then measured as the change in the difference between Cournot and competitive outcomes from the pre- to the post-retirement sample.

However, the parameters used in the counterfactual analysis, such as marginal cost of generators, will be estimated within a multi-unit uniform framework, exploiting the equilibrium property of the observed SFE in the pre-retirement sample. This approach differs from standard structural estimation, where the same model is used for both estimation and counterfactual analysis. As long as strategic components are removed during the estimation process, using the estimated parameters for counterfactual equilibrium computation with a different model is acceptable. For more details on parameter estimation, please refer to Section 5.3.

[24]This builds on Klemperer and Meyer (1989), who show that multiple Supply Function Equilibria (SFE) are bounded by the Cournot and competitive equilibria. The Cournot outcome thus represents the upper bound of potential impacts, as it represents the maximum possible effect among plausible counterfactual SFEs.

[25]This method of measuring market power (margin) is widely adopted in the literature, including Borenstein et al. (2002), Wolfram (1999), Mansur (2007), Reguant (2014), and etc.

[26]Inconsistencies arise when comparing the market outcomes observed in the pre-retirement sample data, generated from the SFE, to the simulated post-retirement equilibrium outcomes.

5 Description of Model, Data and Parameters

5.1 Model

The Cournot model used for counterfactual equilibrium computation is simlar to that developed by Bushnell et al. (2008), which was tailored to the wholesale electricity market environment. The model does not account for transmission congestion.

Firm's problem In the (day-ahead) market held in time t and hour h, each strategic firm $i \in \{1, \ldots, N_{st}\}$ simultaneously decides on the profit-maximizing amount of electricity generation, q_{ith}, facing a constraint that q_{ith} cannot exceed its total capacity $q_{i,max}$. The firm's problem is summarized below:

$$\max_{q_{ith}} \ \pi_{i,th}(q_{ith}\ , \mathbf{q}_{-ith}) \ = \ p_{th}\ (q_{ith}\ , \mathbf{q}_{-ith})\ [q_{ith} - q^f_{ith}] \ + p^f_{ith}\ q^f_{ith} \ - \ C(q_{ith}) \tag{1}$$

$$s.t. \quad q_{ith} \geq 0 \quad \text{and} \quad q_{ith} \leq q_{i,max}$$

where p_{th} is the market equilibrium price, which is a function of equilibrium quantities of firm i and other strategic firms (q_{-ith}), and $C(q_{ith})$ is the cost.[27] A common practice among the electricity-generating firms is to forward contract a certain amount of their generation with the demand side (retail companies), shown as q^f_{ith}, at a predetermined price of p^f_{it}. As the contracting happens long before the actual generation happens, the forward contracted quantity and the price are exogenous at the time of production decision. Because q^f_{ith} does not respond to market price p_{th}, it must be subtracted from the final quantity produced by the firm.[28] Details of how I construct the forward contracted quantity, q^f_{ith}, is provided in Section 5.3.

Residual demand curve The residual demand is the demand faced by N_{st} *strategic firms* together, which is required to compute the market price, p_{th}, within the model. The residual demand, $Q_{s,th}$, equals the aggregate market demand ($\overline{D}_{th}$) less the electricity generated by *non-strategic* suppliers together ($Q_{ns,th}$), as shown below.[29]

[27] As I do not account for transmission congestion in the model, the equilibrium price computed here corresponds to the system clearing price (i.e., Energy Component Price), not the nodal price (i.e., Locational Marginal Price).

[28] Because p_f disappears from the F.O.C. after differentiating the profit with respect to q_{ith}, we only need q^f_{ith} information when solving the equilibrium.

[29] $\overline{D}_{th}$ is the aggregate market demand net of ex-post net imports (i.e., imports minus exports). In New England, net imports are largely unresponsive to regional price differences and are usually close to the transmission capacity limit. See Online Appendix C.3.2 for details on how import/export quantities are treated in constructing the residual demand.

$$Q_{s,th}(p_{th}) = \overline{D}_{th} - Q_{ns,th}(p_{th})$$

Although the aggregate demand ($\overline{D}_{th}$) is almost perfectly price inelastic, the quantity supplied by non-strategic firms together ($Q_{ns,th}$) is responsive to the market price, making the residual demand to be price responsive as well.

Strategic firms are chosen from among the large-scale firms that operate several power plants (i.e., multi-unit firms). I categorize small-scale *fringe* suppliers, most of which operate a single power plant, as non-strategic firms. The non-strategic firm category also includes firms with considerable scale that operate several power plants, but identified as not capable of behaving strategically in a given market environment. These non-strategic firms, therefore, supply electricity at the marginal cost. Section 6.2.2 provides more details of the categorization of strategic and non-strategic firms.

Because I observe the complete set of price and quantity bids of firms in the market, I can construct a residual demand curve for the market (t, h) directly from the bids in a non-parametric way. Specifically, I generate the supply schedule of non-strategic firms ($\sum Q_{ns,th}(p_{th})$) from their supply bids and then subtract it from the aggregate demand ($\overline{D}_{th}$) to form a residual demand curve.

However, for computational purposes within the model, it is preferable to use a smooth, parametric functional form for the residual demand curve. Therefore, I adopt a log-linear demand specification as shown below.

$$Q_{s,th} = \alpha_{th} - \beta_{th}\, ln(p_{th}) \quad \Leftrightarrow \quad p_{th} = \exp((\alpha_{th} - Q_{s,th})/\beta_{th}) \tag{2}$$

Although the log-linear specification is widely used in the literature (including Bushnell et al. (2008)), it also provides a good fit for the shape of the actual residual demand curve constructed from bids. Online Appendix C.3.1 contains examples showing the fit between the actual residual demand and the log-linear demand curve.

The parameters α_{th} and β_{th} are estimated before running the counterfactual simulation. α_{th}, the intercept of the residual demand, α_{th}, is obtained by plugging in the observed price and the sum of strategic quantities (P_{th}, $Q_{s,th}$) from the pre-retirement sample into the specified demand curve. The slope of the residual demand, β_{th}, is estimated from the actual demand curve constructed from bidding data. Further details on the estimation of the residual demand slope are provided in Section 5.3.1. Throughout the analysis, I assume that strategic behavior and marginal costs of non-strategic firms do not change due to the transition. This implies that the bids of non-strategic suppliers also remain constant throughout the transition. The assumption allows me to use the residual demand curve estimated from the pre-retirement sample data in the computation of post-retirement equilibrium.

Cost function A firm operates generating units (or power plants) that have different marginal costs.[30] I specify the marginal cost of each generating unit to be constant over quantity, so that the cost function of a firm to be a piece-wise linear function.[31] If a firm operates a total J number of generating units, the marginal cost function is represented as below:

$$C'(q_{it}) = mc_{ijt} \qquad \text{if} \qquad q_{it} \in (\sum_{k=1}^{j-1} q_{ikt}, \sum_{k=1}^{j} q_{ikt}) \tag{3}$$

The unit-specific marginal cost, mc_{ijt}, is estimated from the bidding data using the optimal bidding model, the estimation procedure of which is detailed in Section 5.2 and Appendix A.2.[32]

The fixed cost of a power plant, which includes start-up or ramping costs, is also an important component of a power plant's cost, especially for baseload generators known for their high fixed costs. When a plant has a high fixed cost, shutting it down and restarting becomes costly, reducing the flexibility of a power plant's quantity adjustment. In this case, the firm's operating decisions may become dynamic, making a static profit maximization framework unsuitable for analysis. Despite this potential issue, I do not incorporate fixed costs into the analysis.[33] Although this is a limitation, developing a model that fully accounts for this intertemporal linkage and estimates fixed costs is challenging. Instead, I excluded the hours of very low-demand (12 AM to 4 AM) from the sample, as these are the hours during which the presence of fixed costs could affect the marginal production decisions of baseload power plants the most.[34] By doing so, the analysis can put more emphasis on the impact of the changing relative marginal costs, resulting from the energy transition, on firms' *marginal* production decisions. In Appendix A.3, I provide further discussion on the cases in which omitting start-up and ramping costs could be an issue, as well as the potential biases that may arise from omitting these costs in the analysis.

[30] Although the terms "power plant" and "generating unit" are often used interchangeably, a power plant may contain multiple generating units. I use "generating unit" in this section because the bidding data – used to estimate marginal costs – is reported at the unit level.

[31] This functional form is widely used in electricity market studies (Bushnell et al. 2008; Ito and Reguant (2016)).

[32] Although it is common to generate marginal costs from fuel prices and heat rate data, directly estimating them better captures the dispersion in marginal costs that arises when the natural gas market is affected by a shock (i.e., an illiquid gas market). See Appendix A.2 for a detailed discussion.

[33] I partially account for the ramping cost of coal-fired power plants by introducing the higher-step price and quantity bids of coal-fired units into the cost function. These bids, which are significantly higher than the lower-step bids, typically reflect ramping costs. See Appendix A.3 for details.

[34] These are hours when the market price of electricity falls below the coal plant's marginal cost, suggesting that production decisions during these periods are driven more by fixed cost considerations than by marginal costs.

Equilibrium computation I solve strategic firm i's profit maximization problem (shown in equation (1)) in market (t, h) to obtain the first-order conditions shown below:

$$
\begin{aligned}
\frac{\partial p_{th}}{\partial q_{ith}} [q_{ith} - q^f_{ith}] + p_{th} - C'(q_{ith}) - \lambda_{ith} \leq 0 \quad \perp \quad q_{ith} \geq 0 \qquad & \forall i \in \mathcal{F}_s \\
q_{i,max} - q_{ith} \geq 0 \quad \perp \quad \lambda_{ith} \geq 0 \qquad & \forall i \in \mathcal{F}_s
\end{aligned}
\tag{4}
$$

These complementarity conditions are similar to those derived in Bushnell et al. (2008). More details of the derivation can be found in Online Appendix C.1. The Cournot equilibrium quantities, denoted as $\mathbf{q}^*_{th} = [q^*_{1th}, \ldots, q^*_{Nth}]$, is the set of firm-specific quantities that simultaneously solves the system of complementarity conditions. I numerically solve $\mathbf{q}^*_{th}$ that satisfies the system of first-order conditions of N_{st} strategic firms.[35] Once the equilibrium quantities are solved, the market price can be obtained by substituting these values into the residual demand curve given in Equation (2).

In the competitive model, firms supply electricity from their lowest-cost generators, absent of strategic considerations, aiming to minimize production costs given the market equilibrium price: $p_{th} - C'(q_{ith}) \geq 0$. Then the competitive equilibrium price is the price at which the aggregate supply equals the aggregate demand which is fixed to the level observed in the data (perfectly inelastic $\overline{D}_{th}$). Once the equilibrium price is determined, firm-level quantities and other market variables can be readily obtained.

5.2 Data

The primary dataset used is the *Day-Ahead* Energy Market Data by the ISO-New England for the winter seasons between 2012 and 2014 (Nov-Feb).[36] Electricity-generating firms participate in hourly day-ahead market auctions, where they submit bids (i.e., energy offer) for each of their generating units. These bids include price and quantity information, represented as $< p_{ijht}, q_{ijht} >$, indicating the minimum price p_{ijht} at which unit j is willing to supply quantity q_{ijht}. This high-frequency bidding data is available at the firm-unit level and is used to measure equilibrium quantities, as well as to estimate the parameters needed for the counterfactual analysis, as explained in Section 5.3. Aggregate electricity de-

[35]To obtain the solution, I use the PATH algorithm, known for its effectiveness in solving mixed complementarity problems (Kolstad and Mathiesen 1991; Ferris and Munson 1998). This computing method has been widely used in previous studies, including Bushnell et al. (2008).

[36]ISO New England operates the wholesale electricity market, which includes the day-ahead and real-time markets. I primarily focus on the day-ahead market because it accounts for the majority of electricity trading and is where strategic interactions between firms are most active.

mand is derived from demand bids submitted by retail companies in the day-ahead auction. The market clearing price used is the Energy Component Price, which clears the entire system before considering local transmission congestion.

Additional data, such as power plant fuel types and nameplate capacities, is sourced from Seasonal Claimed Capability data (from forward capacity auction). Data on planned power plant retirements and installations is collected from the ISO-NE website and EIA website (U.S. Energy Information Administration). Fuel price data is obtained from various sources. The daily natural gas spot price data (index) is sourced from Natural Gas Intelligence, and the coal spot price data is obtained from SNL Energy.

5.3 Parameter Estimation

Three main parameters are estimated for used in the counterfactual analysis: the residual demand slope (β_{th}), generator marginal costs (mc_{ijt}), and forward contracted electricity quantities (q^f_{it}). These estimations are conducted using the *optimal bidding* model and data from the hourly day-ahead market auction, leveraging the equilibrium properties of the Supply Function Equilibrium (SFE) from which the bidding data is generated. Note that the model used for estimating parameters differs from the Cournot model used for counterfactual equilibrium computation. This section provides an overview of the estimation process, with detailed estimation procedure available in Appendix A.

5.3.1 Residual demand slope

The parameter β_{th} in Equation (2), representing the price elasticity of non-strategic supply, is estimated using a strategy similar to that employed in Ito and Reguant (2016). That is, I construct the actual residual demand curve from the bids in a non-parametric way and then fit it with a parametric function. Specifically, for each market (t, h), I construct the supply schedule of non-strategic firms ($\sum S_{ns,th}(p_{th})$), which is possible because I observe the entire distribution of bids submitted by non-strategic firms, not only the equilibrium price and quantity. Subtracting this supply schedule from the aggregate demand ($\overline{D}_{th}$) forms a residual demand curve.[37] Then, I fit a log-linear function, shown in equation (2), to the constructed curve to estimate the slope, β_{th}.[38] I estimate β_{th} separately for each market (t, h) to account

[37]Note that $\overline{D}_{th}$ already accounts for imports and exports, as it is constructed by subtracting ex-post net imports (i.e., net interchange) from aggregate demand. Therefore, I omit import and export bids when calculating the slope of the residual demand curve. For justification on why this omission does not critically affect the slope estimates, see Online Appendix C.3.2.

[38]The log-linear specification effectively captures the nonlinear shape of the residual demand curve. Figure C.2 in Online Appendix illustrates the estimated fit. As detailed there, the log-linear form provides a better fit than the linear specification, especially when the original curve is lumpy, and it smooths the curve comparably to Gaussian-kernel smoothing. See Online Appendix C.3.1 for details.

for potential variations in the price responsiveness of the non-strategic supply under different market conditions.[39]

5.3.2 Marginal cost

The most common approach to obtaining marginal costs of (thermal) electricity generators (power plants) is to measure the marginal costs using the fuel price index data (aggregate-level data) and the heat rate of generators (as seen in studies by Wolfram 1999; Borenstein et al. 2002, and others). This approach, however, fails to capture the differences in marginal costs among gas-fired plants, which result from the increasing dispersion in their gas procurement prices when pipeline congestion leads to stress in the gas spot market.[40]

To address this issue, I employ the estimation techniques developed in the empirical auction literature (Wolak 2003; Reguant 2014; Ryan 2021; Kim 2022) to estimate the marginal costs that rationalize the bids submitted by firms in electricity auctions. Although this approach requires modeling the optimal bidding decisions of firms and additional computation effort, it performs better in capturing the dispersion of the marginal opportunity costs at the firm-plant level than the marginal cost measured from data. The estimation exploits the fact that the equilibrium bid observed in the data maximizes a firm's (expected) profit, leading to the following first-order condition: $b_{ijt} = mc_{ijt} + \text{markup}_{it}$. Utilizing the rich bidding data together with this estimation technique enables me to estimate the firm-unit-specific marginal cost parameter, mc_{ijt}, from the first order condition, at the daily level. Note that estimating marginal cost is not feasible for generating units located far away from the market clearing price (i.e., not marginal), including some fringe and baseload units (e.g., nuclear).[41] I use the price bid as a measure of marginal costs for these units, exploiting the fact that firms have no incentives to add markup when bidding for a non-marginal generating unit.[42] For more details on the bidding model and the estimation procedure, please refer to Appendix A.

Figure 5 summarizes the marginal costs of gas units, coal units, and the hypothetical gas units, plotted

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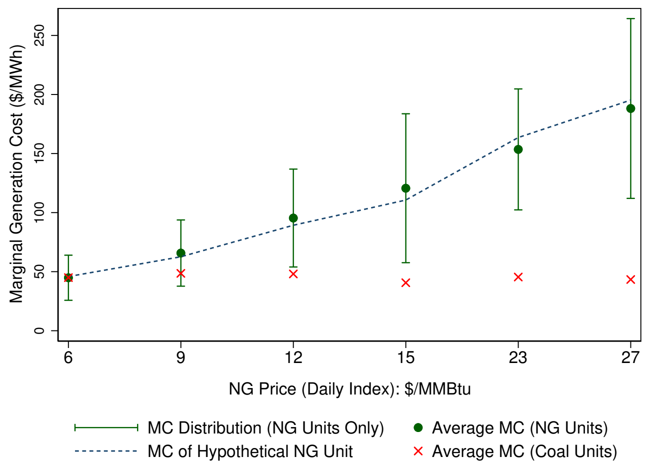
[39] This method differs from that in Bushnell et al. (2008) which estimated a single slope parameter using only equilibrium prices and quantities for the entire sample.

[40] The fuel price index – the only available fuel price data – is constructed as a weighted average of firm-plant-level transaction prices in the gas spot market. It serves as a good proxy for a plant's spot price when differences in plant-level prices are small. However, if prices are dispersed across plants, using the index can introduce measurement error. See Online Appendix C.2.1 or Kim (2022) for details.

[41] The optimal bidding model allows estimation of marginal costs for generating units that are frequently marginal and thus strategically used by firms. However, this approach cannot be applied to fringe units that bid excessively high to avoid dispatch, or to baseload nuclear units that consistently bid near zero.

[42] The marginal costs relevant for the equilibrium computations are those of generating units that are close to being marginal. Therefore, the treatment of non-marginal units' costs has little impact on the results.



Notes: The graph shows the distribution and the mean of marginal costs of NG-fired generating units (excluding the top and bottom 1 percentile), coal-fired generating units, and hypothetical NG-fired units used in the counterfactual analysis. The values are plotted across the six selected days that have different levels of NG prices which are displayed on the horizontal axis.

Figure 5: Marginal Cost Summary

against the gas price levels (price index) of the days in the sample. The daily estimates of marginal costs for the gas units are shown as a distribution, verifying the existence of dispersion in their marginal costs. The average pattern of the estimates shows that the relative marginal cost of gas generation versus coal generation changes along with the increasing gas prices.

5.3.3 Forward contracted electricity

Data does not exist for the forward contracted position as it is determined through confidential bilateral negotiations between the electricity-generating firms and the demand side (retail companies). I impose a structure on the forward contracted quantity by assuming that it is a percentage (γ_{ih}) of the firm's actual hourly generation, represented as $q^f_{ith} = \gamma_{ih} q_{ith}$. I estimate hourly forward contract rates, γ_{ih}, from the bidding data, utilizing the estimation procedure of Kim (2022) and Reguant (2014), the details of which are in Online Appendix C.4.

Although the contracted rate differs by firm and hour, the average of firm-level rates is about 75% during off-peak hours (roughly from 11 PM to 6 AM), and it is about 30% during peak hours.[43] Table C.1 in Online Appendix summarizes the forward contract rate estimates for a subset of firms. The firm-specific rate parameter remains constant for each hour, but the contracted quantity q^f_{ith} can vary across days due to variation in the firm's daily production level (q_{ith}).

[43]Note that the forward contracting rate is estimable only for large-scale firms operating many generating units. The mean rate reported here reflects 11 strategic firms with estimates significant at the 5% level.

I use the same q^f_{ith} estimates from the pre-retirement sample when computing the post-retirement counterfactual equilibrium, although the extent of contracting may change in the counterfactual environment.[44] However, the misspecified forward contracted quantity will not significantly affect the main results because I have excluded, from the analysis, the hours of very low-demand (from 12 AM to 4 AM) during which the forward contract is high and binding.

6 Baseline Results

I first report the results computed for the baseline case in which the industry structure does not change as a result of the transition process. The results of each day-hour market, (t, h), in the sample are summarized by aggregate demand and gas price levels, which vary across markets. Note that it is common in electricity market studies to analyze results separately by demand (e.g., *peak* hours vs.*off-peak* hours), as the market characteristics and competitiveness are known to differ by the demand level.[45]

I group the demands into four bins (D1 to D4) and the gas prices into three bins (G1-low, G2-med, and G3-high), then report the average values within each bin.[46] The numbers assigned to D (D1 to D4) represent increasing levels of demand, with D1 indicating the lowest demand level and D4 the highest. Similarly, the numbers assigned to G (G1-low to G3-high) indicate increasing gas price levels.

6.1 Residual demand slope estimates

Panel (A) of Table 3 summarizes $\hat{\beta}_{th}$, the estimated slopes of residual demand curves of each day-hour market (t, h); the mean is around 4.04 GWh/$ with some variation across markets.[47] To examine how the slope differs by the demand and gas price levels of the market, I run a simple regression of $\hat{\beta}_{th}$ on demand and gas price variables. Panel (B) reports the coefficients of the regression. One interesting finding is that $\hat{\beta}_{th}$ is smaller when the gas price is higher, shown by a negative coefficient of the "NG price" variable in Panel (B). This indicates that the supply from the non-strategic firms becomes relatively more

[44]Research shows that forward contracting incentives can be affected by changes in market structure (Brown and Eckert 2017; Miller and Podwol 2020). Online Appendix C.4.3 discusses how these findings apply to my setting and offers conjectures on how incentives may change in response to the energy transition.

[45]In typical market conditions – absent gas price shocks or disruptions – market power is less likely to be exercised during off-peak hours and more likely during peak hours (Borenstein and Bushnell 1999; Borenstein et al. 2002). Note that D1 and D2 roughly correspond to off-peak demand levels (5 AM -10 AM and 11 PM), whereas D3 and D4 align with peak demand (11 AM -10 PM). Bin cutoffs are based on the observed distributions of demand and gas prices.

[46]Table B.1 and Figure C.5 of the Online Appendix provide the summary and details of the categorization of demand and gas price variables, respectively.

[47]I also computed demand elasticities evaluated at the observed pre-retirement equilibrium, and find that market-level elasticities range between 0.15 and 2.87, with a mean around 0.64. Also, variations in elasticities across demand and gas price levels are similar to those of β.

(A) Summary statistics of $\hat{\beta}_{th}$							
mean:	4.04	s.d.:	1.02	min:	2.52	max:	8.30
(B) Regression result of $\hat{\beta}_{th}$ on demand and NG price of the market (t, h)							
	Demand:	0.004		NG price:	-0.04		
		(0.02)			(0.01)		

Notes: $\hat{\beta}_{th}$ is the estimated slope of the residual demand curve of day t-hour h (*unit*: GWh/\$). Section (B) reports the estimates of OLS regression of $\widehat{\beta_{th}}$ on Demand$_{th}$ and NG price$_t$ variables. Demand is the aggregate market demand of the day t- hour h market (*unit*: GWh). Gas price is the spot gas price index of day t (*unit*: \$/MMBtu). Standard errors in the parenthesis. N = 348.

Table 3: Residual Demand Slope Estimates ($\hat{\beta}_{th}$)

price-inelastic on days with higher natural gas prices. Because the supply bids of non-strategic (fringe) firms reflect their marginal costs, the inelasticity of the residual demand can be linked to the dispersion of marginal costs among gas generators, which increases further as the overall gas price increases, as documented in Figure 5.[48] Note that I do not find a strong (significant) correlation between $\hat{\beta}_{th}$ and the demand.

6.2 Counterfactual equilibrium prices

6.2.1 Competitive prices

Panel (A) of Table 4 summarizes the competitive prices simulated for the pre- (*Before*) and post-retirement (*After*) samples. The competitive prices changed overall after the transition, indicative of a change in the marginal cost distribution resulting from the transition. The first two rows of the table show that competitive prices increase the most in the lowest-demand sample (D1) and decreases the most in the highest-demand sample (D4). Subsequent panels from (G1-low) to (G3-high) show that the higher the gas price is, competitive prices tend to increase more after the transition, although some variation exists across the demand.

6.2.2 Selection of strategic firms

In order to compute the Cournot equilibrium, the set of strategic firms need to be determined. Although it is common to assume that large-scale firms with high market share are strategic players, it difficult to pin down several that would indeed behave strategically when the shares are relatively balanced across many of these firms and if there is no explicit cutoff values used for shares or scales deem-

[48]The source of the documented marginal cost dispersion is explained more in Online Appendix C.2.1.

	(A) Competitive Price					(B) Cournot Price				
		Low Demand $\Rightarrow$		High Demand			Low Demand $\Rightarrow$		High Demand	
	Total	(D1)	(D2)	(D3)	(D4)	Total	(D1)	(D2)	(D3)	(D4)
Full Sample										
Before	98.5	75.9	87.4	88.3	124.9	112.6	81.2	95.5	99.7	149.0
After	97.8	81.8	88.7	87.3	118.9	122.1	96.4	108.1	108.8	153.5
Sample by Gas Price Levels										
(G1 - low) Low Gas Price										
Before	60.3	51.1	52.4	53.8	75.7	67.0	53.5	58.4	58.4	87.2
After	57.9	50.9	52.3	52.3	69.7	69.8	58.8	59.9	61.8	87.7
(G2 - med) Med Gas Price										
Before	90.4	75.4	79.0	81.4	119.4	100.5	83.0	84.3	88.2	137.2
After	89.1	81.9	76.7	79.0	112.0	108.6	98.1	91.6	96.7	138.8
(G3 - high) High Gas Price										
Before	151.1	115.0	132.4	154.1	164.5	178.1	121.5	144.7	168.8	195.1
After	153.0	129.4	137.7	155.2	159.8	196.5	152.0	173.5	192.4	202.0

Notes: This table compares equilibrium prices simulated under competitive and Cournot assumptions, *before* and *after* the retirement-induced transition as defined in the baseline scenario. Prices are averaged by demand and gas price bins. Demand bins: (D1) $<$ 14 GW, (D2) 14 -15.5 GW, (D3) 15.5 -17 GW, (D4) $>$17 GW. Gas price bins: (G1-low) \$4 - \$9/MMBtu , (G2-med) \$9 -\$15/MMBtu, and (G3-high) \$15–\$27/MMBtu. Each demand-gas price bin contains roughly the same number of observations. $N = 348$.

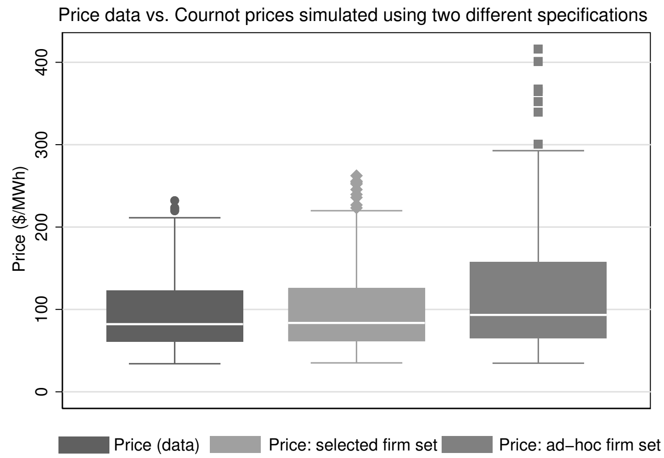
Table 4: Simulated Competitive and Cournot Prices

ing a firm to be strategic. Moreover, even a large-scale firm can behave quite competitively depending on the market condition, because firms compete in the multi-unit uniform auction in this market. In this uniform auction setting, a firm has an incentive to behave strategically only when its generator (or power plant) is close to being marginal, the probability of which depends critically on the demand and supply conditions of the market.[49]

To address these concerns, I select strategic firms based on what the data and the model predicts, among large-scale firms with considerable market share (calculated based on their infra-marginal quantity).[50] I select firms identified as behaving strategically in the actual equilibrium (SFE of the pre-retirement sample), whose quantity, as *observed* from the data (generated from the SFE), considerably differs from and is smaller than the counterfactual *competitive* quantity of the pre-retirement sample. The deviation of the actual quantity from the competitive benchmark indicates that the firm was mak-

[49]For example, when the market demand is high, a large-scale firm that only operates the low-cost generators will not bid strategically, despite having a high market share, as none of its generators are close to being marginal. If so, treating this firm as a strategic player in the Cournot computation could exaggerate the strategic outcome.

[50]I limited the selection to firms with capacity exceeding 200 MW. Although I did not explicitly restrict the selection to firms with high market shares, most firms chosen through this method had substantial market shares. This shows that the approach is especially useful for excluding firms with large infra-marginal quantities – such as those owning large nuclear plants – but lacking marginal units for strategic bidding.



Notes: The figure displays three price distributions for the *pre-retirement* situation. The left distribution represents actual equilibrium (SFE) prices observed in the data. The middle distribution shows Cournot prices simulated using a selected set of strategic firms. The right distribution shows Cournot prices simulated using the fixed set of firms (8 firms with the largest scales) that are chosen in an ad-hoc way and fixed throughout the sample.

Figure 6: Observed Prices vs. Cournot Prices Simulated using Selected Firm Set and Ad-hoc Firm Set

ing strategic production decisions under the given market conditions.[51] The rest of the firms not selected are categorized as *non-strategic* firms that behave competitively, supplying at a cost-minimizing fashion. I select firms separately for each market (t, h), and the size and composition of the group of strategic firms differ across markets, with a total of 20 firms identified as strategic throughout the entire sample.[52] I assume that the strategic firm set will not change in the counterfactual environment.[53] For a detailed discussion of the selection method, see Appendix A.4.

Model Fit Figure 6 presents, from left to right, the distributions of equilibrium prices observed from data (SFE), Cournot prices simulated with the selected strategic firms, and Cournot prices simulated with an ad-hoc set of strategic firms, all for the *pre-retirement* sample. The ad-hoc firm set, which consists of a total of 8 firms with the largest scales, represents a firm set arbitrarily chosen solely based on the scale of firms. The ad-hoc firm set is fixed throughout the sample unlike the selected firm set, the composition of which differs slightly across the sample accounting for the variation in market condi-

[51]The core idea behind my approach – selecting firms based on observed strategic behavior in the data – is similar to that of Ryan (2021). To justify the selection of strategic firms over non-strategic firms, Ryan (2021) showed that bids submitted by strategic firms responded significantly to transmission congestion (a source of strategic behavior), whereas those of non-strategic firms did not.

[52]The number of strategic firms at the market level (t, h) ranges from 7 to 13. For a summary of firm characteristics, refer to Table 6 and Table C.2 in the Online Appendix.

[53]Because the selection process relies on information from the pre-retirement market, a firm that was previously non-strategic could begin behaving strategically in the counterfactual environment. To address this, I impose additional measures – described in Appendix A.4 – to ensure the selected firm set is as comprehensive as possible. Moreover, it is standard in the literature using Cournot simulations to fix the set of firms throughout the counterfactuals, unless entry and exit are explicitly modeled in a dynamic setting.

tions.

First, when comparing the distribution of observed prices (left) with Cournot prices simulated using the selected firm set (middle), I find that simulated Cournot prices closely align with the observed equilibrium prices, indicating a good fit. Additionally, I find a good fit between the firm-level quantity computed from the Cournot model and the actual firm-level quantity, as shown in Figure C.10 in the Online Appendix. These findings validate the use of the Cournot equilibrium to approximate the actual strategic equilibrium (SFE).

Comparing of all three distributions, including the last one simulated with a fixed set of large-scale firms (ad-hoc firm set), reveals that the selected firm set performs relatively better than the alternative firm set in terms of model fit. Specifically, the distribution of prices simulated with the selected firm set (middle) aligns more closely with the distribution of observed prices (left) than the distribution of prices simulated with the ad-hoc firm set (right).

Strategic Cournot prices Panel (B) of Table 4 summarizes the Cournot prices simulated for the pre- (*Before*) and post-retirement (*After*) samples. As shown in the first two rows of the table, strategic prices increase more in the low-demand sample (D1 and D2) than in the high-demand sample (D3 and D4), on average. When examining the pattern across different gas price levels, I find that strategic prices, on average, increase more under higher gas price levels (from (G1-low) to (G3-high), for *Total*).

6.3 Measuring the change in market power

The market power is measured as the extent to which the strategic Cournot price departs from the competitive level. The market power of each day and hour market, (t, h), is as follows:

$$\Delta P_{T,th} = \text{markup }_{T,th} = P_{\text{Cournot},T,th} - P_{com,T,th}$$

where, T denotes whether the sample is pre-retirement or post-retirement.[54] Because my focus is on measuring the *change* in market power resulting from the transition, I use $\Delta\Delta P_{th}$ as the primary measure of interest:

[54]This approach to measuring market-level markup is widely used in electricity market studies (Wolfram 1999; Borenstein et al. 2002; Mansur 2007; Reguant 2014, etc). Conceptually, it resembles assessing market power in an oligopoly by comparing outcomes to a competitive benchmark. Firm-level markups are less informative in this quantity competition setting, as only a single market price – determined by all strategic firms' supply decisions – is observed. Moreover, examining the markup of marginal price setter is not feasible, as the Cournot model does not define a price-setting firm.

$$\Delta\Delta P_{th} = \Delta P_{post,th} - \Delta P_{pre,th}$$

This represents the difference between the pre-retirement market power and the post-retirement market power. A positive (negative) value of $\Delta\Delta P_{th}$ indicates an increase (decrease) in market power after the transition, which results in increasing (decreasing) the strategic price by $\$\Delta\Delta P_{th}/\text{MWh}$ more relative to a change in the competitive price.

Result Table 5 reports the $\Delta\Delta P_{th}$ of each day-hour market (t, h) summarized by demand (columns D1 to D4) and gas price level (rows G1-low to G3-high) of the market.[55] On average, the market power increases after the transition, raising the price additionally by \$9.8/MWh relative to the change in competitive prices (shown in the first row of the column *Total*). When examining the pattern across different demand levels, shown in the first row of the table, $\Delta\Delta P_{th}$ is higher in the low-demand sample (columns (D1) and (D2)) than in the high-demand sample (columns (D3) and (D4)), though not distinctive. This indicates that the energy transition is expected to increase the market power more in the low-demand sample than in the high-demand sample.

However, it is important to note that the *absolute* level of market power, ΔP_{th}, remains lowest during low-demand (off-peak) hours and highest during high-demand (peak) hours in both pre-retirement and post-retirement cases, which corresponds to the well-established findings in the literature. Figure C.9 in the Online Appendix presents the absolute market power levels, averaged within each demand bin (D1 to D4), for the pre-retirement sample (panel (a)) and the post-retirement sample (panel (b)). Note that $\Delta\Delta P_{th}$ quantifies the level difference between these panels.

A more distinct pattern emerges from the summary across the gas prices, presented in rows from (G1-low) to (G3-high). $\Delta\Delta P_{th}$ consistently shows a positive value, with a notable increase as we move from (G1-low) to (G3-high) in the *Total* column, with $\Delta\Delta P_{th}$ rising from 4.9 to 16.6, on average. This indicates that energy transition is expected to increase the market power more when the gas prices are higher.

To summarize, two patterns emerge from the baseline results: first, market power increases more due to the transition when gas prices are higher; and second, low-demand hours suffer more from the increased market power than the high-demand hours. The result can be interpreted as follows; if

[55] The percentage change in $\Delta\Delta P_{th}$, shown in Table C.6 in the Online Appendix, exhibits patterns qualitatively similar to those of the level changes. I continue to report results in level changes because percentage changes can be sensitive to variation in average electricity prices, which is substantial across the sample.

		$\Delta\Delta P = \Delta P_{\text{post}} - \Delta P_{\text{pre}}$			
		Low Demand		$\Rightarrow$	**High** Demand
	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P$	9.8	9.2	11.3	10.7	8.9
Further Controlling for the Daily Gas Prices					
(G1-low) Low Gas Price					
$\Delta\Delta P$	4.9	5.4	1.6	5.0	6.4
(G2-med) Med Gas Price					
$\Delta\Delta P$	9.4	8.4	9.6	10.8	8.9
(G3-high) High Gas Price					
$\Delta\Delta P$	16.6	16.1	23.4	21.9	11.5

Notes: Table reports the average market-level $\Delta\Delta P_{th}$. Demand is categorized into four bins: (D1) below 14 GW, (D2) between 14 and 15.5 GW, (D3) between 15.5 and 17 GW, and (D4) above 17 GW. The number of observations in each demand bin is roughly the same. The gas price bins are defined as follows: (G1-low) for days with gas price index between \$4 and \$9/MMBtu, (G2-med) for days between \$9 and \$15/MMBtu, and (G3-high) for days above \$15/MMBtu up to \$27/MMBtu. Because I selected days in the high-cost regime, even the "Low Gas Price" category includes days with gas prices higher than the normal (lowest) level of \$4/MMBtu. N = 348.

Table 5: Change in the Market Power, $\Delta\Delta P_{th}$

an industry transitioning to having a higher share of gas generation were to experience the same gas price shock seen during the winters of 2013-2014, wholesale electricity prices would rise even more than before the transition, primarily due to increased market power. The market power increase due to the transition would be more intense when the gas price shock is more severe, as indicated by the increase in $\Delta\Delta P_{th}$ from (G1-low) to (G1-high), and more prevalent during the low-demand hours (D1 and D2) as shown earlier.

These patterns are also documented from a simple regression of $\Delta\Delta P_{th}$ on the market-level demand and gas price levels, shown in Table B.2 in the Appendix. The coefficient estimate of the gas price variable is 0.81 and significant, capturing the positive correlation between the gas price and the $\Delta\Delta P_{th}$. The coefficient for the demand variable is negative at -0.07, but not significant, implying that the relationship between $\Delta\Delta P_{th}$ and the demand is not as strong as that with the gas price.

6.4 Firm-Level Analysis: Exploring the Source of Market Power

Given that the results of the baseline case indicate a change in the strategic behavior of firms resulting from the energy transition, it is important to examine the factors that may have contributed to these findings. I investigate how the relevant market variables and the strategic responses of firms are affected by the retirement, accounting for the heterogeneity among firms. Once the mechanism behind the baseline

Firm Type	No. of Firms	Total Capacity (MW)	Firm Capacity (MW)		No. of Units
			mean	s.d.	mean
Retired firm	4	6,245	1,561	665	8.3
Non-retired firm					
Gas-intensive	8	9,308	1,163	988	4.4
Balanced	8	9,890	1,236	709	10.1

Notes: The table summarizes the characteristics of strategic firms, categorized into three types: retired firms, gas-intensive firms, and balanced firms. The "No. of firms" column reports the total number of firms in each firm type and "Total capacity" column reports the sum of the capacity of all firms by firm type. The "Firm capacity" columns provide the mean and standard deviation of the *firm-specific* capacities by firm type. The "No. of units" column reports the average number of generating units (plants) operated by each firm within the respective firm type category.

Table 6: Summary of Strategic Firms: by Firm Type

results is established, we can more effectively identify the underlying forces contributing to changes in outcomes in the additional counterfactual cases considered in Section 7, which are marginal departures from the baseline scenario.

How does the retired firm's production change? I begin by examining how the production of *retired firms* (i.e., firms that own the retired baseloads) changes as their retired plant is replaced with a gas power plant of the same capacity. In Figure C.11 of the Online Appendix, I plot the average quantity produced by retired firms together, before and after the transition, separately by demand and gas price levels of the market. Although the total capacity of each retired firm remains unchanged, their combined production decreases, particularly during lower-demand hours (D1 and D2) and under higher gas prices (G1-low $\rightarrow$ G3-high). In other words, during low-demand hours, production increasingly shifts away from retired firms toward other firms the higher the gas prices are.[56]

Which types of firms are active in exercising market power? The strategic firms used in the analysis are mostly large-scale firms with considerable market shares, yet they exhibit heterogeneity in characteristics, including the composition of fuel technologies. Therefore, I investigate which *type* of strategic firms more actively exercise market power in response to the changes in the competitive environment resulting from the grid's transition.

I categorized strategic firms into three groups that differ in their fuel technology composition. The "Retired firm" refers to firms that previously owned the retired power plants, whose generation mix is directly affected by the transition. Among firms not part of the retired category, those with more

[56]The reduction in quantity that I document for the retired firms is not a result of fixed cost differences between a baseload power plant and a gas power plant. This is because the model used for computing these quantities does not account for fixed costs.

than 80% of their generation coming from gas power plants are categorized as "Gas-intensive" firms. The rest of the firms, labeled as 'Balanced", are those generating electricity using relatively diverse fuel technologies. Table 6 summarizes the characteristics of firms by their type.[57]

A strategic firm exercising market power would profitably *withhold* the quantity relative to the level produced if it instead behaved as a price taker. Therefore, I measure the firm-level withholding – or the net strategic quantity – as a difference between a firm's Cournot quantity, $q_{i,st}$, and the competitive quantity, $q_{i,com}$. The negative net strategic quantity (i.e., $q^*_{i,st} = q_{i,st} - q_{i,com}$) indicates a withholding of production at the firm level.

As I am interested in the *change* in the firm's strategic behavior due to the transition, I select firms that *additionally* withhold their net strategic quantity ($q^*_{i,st}$) after the transition, but enjoy a higher markup by doing so.[58] That is, for each (t, h) market, I find firms whose (i) net strategic quantity is negative in both pre- and post-retirement states ($q^*_{i,st,pre} < 0$ and $q^*_{i,st,post} < 0$), (ii) the extent of withholding *increases* in the post-retirement state compared to the pre-retirement state ($q^*_{i,st,post} < q^*_{i,st,pre}$, or $\Delta q_{i,wh} = |q^*_{i,st,post}| - |q^*_{i,st,pre}| > 0$) and (iii) markup increases further as a result of the additional withholding ($\text{markup}_{i,post} > \text{markup}_{i,pre} > 0$).[59] The method allows me to identify firms that more actively exercise market power throughout the transition process, among those with a reasonably large market presence.[60]

Figure 7 reports the percentage share of each firm type among the identified *withholding firms*, summarized over different demand and gas price levels of the market (the same categories used in Table 5). On average, the gas-intensive firms take up almost 60% share of the withholding firms, though some variation exists across categories: they profitably withhold the quantity even more after the transition compared to other types of firms, more so when the demand is lower and gas prices are higher.[61] In Column (1) of Table 7, I also examine the size of withholding by firm type, where I find that the extent of withholding is significantly greater for gas-intensive firms compared to others. This suggests that changes in market conditions resulting from the retirement and replacement process under the baseline

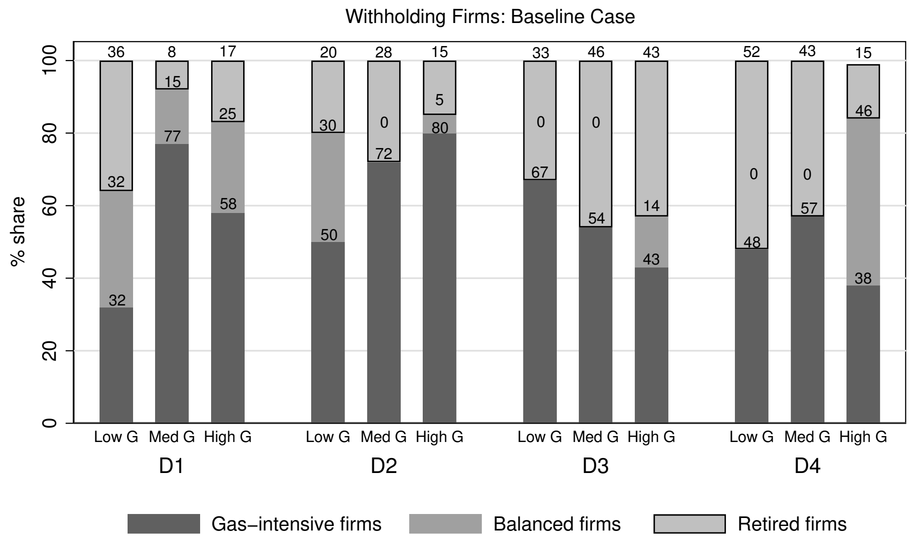
[57] Balanced firm's generation set is a mix of coal, nuclear, natural gas, oil, hydro, and biomass. Summary of the fuel mix of balanced firms can be found in Table C.11 of the Online Appendix.

[58] I select firms among those with at least a 10% share of total strategic supply (Q_{st}).

[59] Condition (iii) ensures that the profit loss from withholding quantity is offset by a gain from a higher price-cost margin. I also confirm that selected firms' markup increases are associated with overall profit gains. For this, I compute a lower bound of net profit gain: Δ profit = $\Delta markup \times q_{af} + markup_{bf} \times \Delta q$. This lower bound assumes a flat marginal cost across all infra marginal output, ignoring the piece-wise-linear cost structure.

[60] About 50% of the selected withholding firms have the highest market share, and the rest are all among the top three.

[61] Although gas-intensive firms are the most frequent withholders, their withholding status does not exhibit a clear pattern when analyzed against demand and gas price levels, as shown in Figure 7. One explanation is that the equilibrium computation relies on supply and demand curves derived from actual data, making the strategic environment (e.g., marginal units, competitor set) noisier than in a controlled simulation. In addition, reporting frequencies at finer demand-gas price bins may introduce more noise than summaries based on broader categories.



Notes: Demand is categorized into four bins, (D1) to (D4), with (D1) representing the lowest demand level and (D4) the highest demand level. Gas prices are categorized into three bins, (G1-low), (G2-med), and (G3-high). The graph reports the percentage of each firm type out of the total number of firms identified as exercising greater market power. For example, an 80% value for 'Gas-intensive firms' in the (D2)-(G2-med) category indicates that among the firms identified as exercising market power in the (D2)-(G2-med) sample, 80% of them were gas-intensive firms.

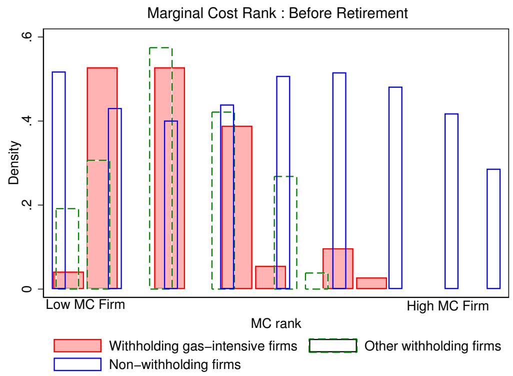
Figure 7: Percentage of Selected Strategic Firm: by Firm Type

case provide gas-intensive incumbent firms with increasingly more ability to exercise market power.

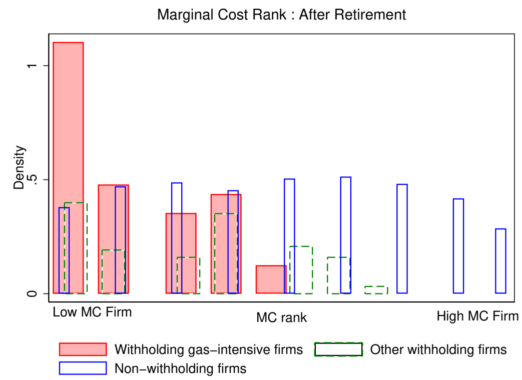
Firm-level marginal cost distribution analysis I examine the exogenous change in the marginal cost distribution, $C'(\mathbf{q}_{st}) = \{C'(q_1), \ldots, C'(q_{N_{st}})\}$, by comparing distributions before (C'_{pre}) and after (C'_{post}) the transition, fixing each firm's quantity to its pre-retirement Cournot quantity, $\mathbf{q}_{st,bf} = \{q_1, \ldots, q_{N_{st}}\}$.[62]

I begin by analyzing how the relative order (rank) of firm-specific marginal costs is affected by the transition. In each (t, h) market, firms are ranked in an increasing order based on their marginal costs (from low cost to high cost) for both the pre- and post-retirement cost distributions. The distribution of assigned ranks at the firm level are then plotted for different firm groups: withholding firms, further divdied into gas-intensive and non-gas-intensive, and non-withholding firms. Figure 8 displays these rank distributions, with Panel (a) representing the ranks for the pre-retirement cost distribution, $C'(\mathbf{q}_{st,bf})_{\text{pre}}$, and Panel (b) for the post-retirement cost distribution, $C'(\mathbf{q}_{st,bf})_{\text{post}}$. Comparing the panels reveals that withholding firms, especially the gas-intensive ones, become relatively low-cost suppliers after the transition. That is, the shaded distribution of ranks, representing that of withholding gas-intensive firms, shifts more towards the lowest rank (skewed more to the right) in Panel (b) compared to Panel (a). The decrease in their relative marginal costs is more pronounced in low-demand (D1) and

[62]Although firms re-optimize their quantities after a change in marginal cost distributions, the re-optimized quantities are not used when evaluating the post-retirement cost distribution (C'_{post}). Thus, the analysis isolates the impact of plant retirements and installations on the cost distribution, prior to firms' adjustments to the new distribution.



(a) MC rank before retirement



(b) MC rank after retirement

Notes: Graphs show the distribution of relative rank of the marginal cost at a firm level, before and after the industry transition. Relatively lower cost firms are assigned a low rank, thus located towards the left portion of the graph.*Withholding* firm refers to firms identified as withholding the quantity *more* after the transition ($\Delta q_{i,wh} > 0$). Panels (a) and (b) shows the (relative) rank of marginal cost of (i) gas-intensive withholding firms, (ii) other withholding firms, and (iii) non-withholding firms that are not identified as withholding the quantity more after the transition.

Figure 8: Marginal Cost Rank: by Firm Type and the Withholding Status

high gas price (G3-high) scenarios, as shown in Figure C.12 of the Online Appendix.

The change in rank is accompanied by an overall increase in the marginal costs of strategic firms. In Figure B.2 of the Appendix, the average change in marginal costs of strategic firms due to the transition is shown across demand (Panel (a)) and gas prices (Panel (b)). The extent of the marginal cost increase is more significant during low-demand hours (D1), when the retired baseloads are the marginal plants of the retired firms, and in high gas price scenarios (G3-high), where the marginal cost difference between the retiring plant and the replacing gas plant is large.

The price elasticity of non-strategic supply The elasticity of non-strategic supply, captured by the slope of residual demand, β_{th}, also affects the decisions of strategic firms. Specifically, the more elastic the non-strategic supply, the more constrained is the ability of strategic firms to profitably withhold quantity. This relationship is confirmed by the first row estimates in Table 7, showing a negative correlation between β_{th} and the additionally withheld firm-level quantity ($\Delta q_{i,wh}$) as well as the extent of market power change ($\Delta\Delta P_{th}$), both of which serve as indicators of market power exertion.

As previously documented with $\hat{\beta}_{th}$ in Table 3 and shown in Figure 9, the residual demand becomes more price *inelastic* on days with higher gas prices. This suggests that the competitive constraint imposed by non-strategic suppliers is reduced on days with higher gas prices, which explains why I find $\Delta\Delta P_{th}$ to be larger under higher gas prices.

	(1)	(2)	(3)
	$\Delta q_{i,wh}$	$\Delta\Delta P_{th}$	$\Delta\Delta P_{th}$
Residual demand slope (β_{th})	-0.07	-3.77	-2.68
	(0.03)	(0.59)	(0.57)
Gas-intensive firm$_i$	0.35		
	(0.06)		
Balanced firm$_i$	-0.05		
	(0.09)		
$\Delta q_{i,wh}$		9.55	
		(1.09)	
Δ MC mean$_{th}$			0.89
			(0.20)
ΔMC mean$_{th} \times\ \beta_{th}$			-0.17
			(0.05)

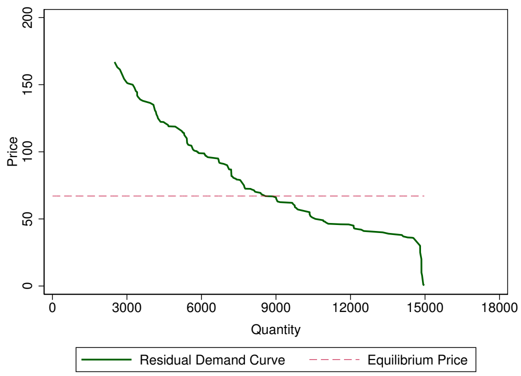
Notes: Column (1) regression is at the firm level. $\Delta q_{i,wh}$ is the change in withholding firm i's withheld quantity in absolute value (*unit*: GW)."Gas-intensive firm" and "Balanced firm" are dummy variables assigned to the withholding firms that are categorized into each firm group. Columns (2), (3) regressions are at the market level. $\Delta\Delta P_{th}$ is the change in market power (*unit*: \$/MWh). Δ MC mean$_{th}$ is the average change in marginal costs of strategic firms, i.e., $\overline{MC}_{th,post} - \overline{MC}_{th,pre}$ (*unit*: \$/MWh). Standard errors in parenthesis. N =334.

Table 7: Regression of Stategic Outcomes on Firm- and Market-Level Variables

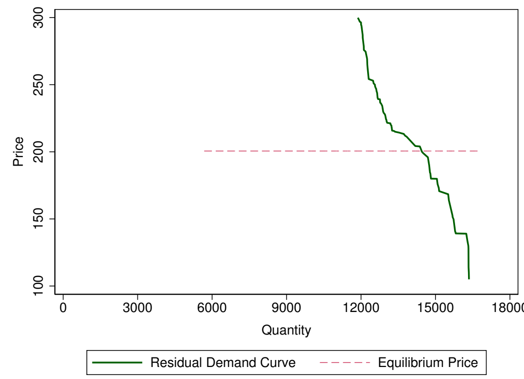
Summary: understanding the baseline case result for $\Delta\Delta$P The examinations help explain the findings from the baseline case analysis. First, the analysis shows that the retirement and replacement process causes a greater disturbance to the market environment when demand is lower and gas prices are higher. For example, the reductions in production by retired firms and the resulting disruptions in the marginal cost distribution are more pronounced in samples characterized by low demand and high gas prices. This explains why the transition has a stronger impact on market outcomes under these situations.

Why does market power increases after the transition? I identify two types of strategic interactions that drive the increase in market power following the transition. The first type occurs between a group of strategic firms and non-strategic firms. The analysis shows that the marginal costs of strategic firms increase after the transition, leading to a collective reduction in their quantities. A reduction in strategic quantity does not necessarily increase market power if it is offset by an elastic supply from non-strategic firms. However, the analysis reveals that non-strategic supply is *inelastic*, particularly on days with higher gas prices. This inelasticity enhances strategic firms' ability to withhold quantity beyond what is implied by the marginal cost increase, contributing to the increase in market power.

Second, strategic interactions among the strategic firms themselves – as reflected in changes in firm-level withholding behavior – further amplify market power. This is evidenced in Column (2) of Table



(a) Low NG price day ($9/MMBtu)



(b) High NG price day ($22/MMBtu)

Notes: Figure shows the actual residual demand curve of the market, generated from the non-strategic firms' bidding data.

Figure 9: Residual Demand Curve: Low vs. High Gas Price Days

7, which shows a strong correlation between the extent of firm-level withholding and increases in unilateral market power. Among these firms, I find that a particular type – large-scale, gas-intensive firms – exploit the retirement situation the most by increasing their withholding in the post-retirement period, especially under lower-demand and higher gas price conditions. This pattern is explained by the fact that, after the transition, gas-intensive firms become relatively low-cost suppliers among strategic firms, particularly in samples with lower demand and higher gas prices, as revealed by the analysis of firm-level cost distributions. As a result, they face more inelastic firm-specific residual demand after the transition, which strengthens both their incentive and ability to withhold output.

7 Industry Structure and the Capacity Installation

This section introduces variations in industry structure by considering several stylized paths of energy transition that differ in installations of new gas generation capacities. Note that the model does not endogenize the capacity investment decision; instead, it takes the decision as given and focuses on the final form of the industry that emerges if investments occur according to the assumed scenario.

Actual installation pattern observed from the data Although new generation capacity installations are still ongoing, several patterns are evident in the planned capacity data from the EIA-860.[63] First, a substantial portion of the new gas generation capacity is proposed by the large-scale incumbent firms that expand their existing gas generation facility. Second, not many firms enter the industry, with almost

[63]EIA-860 form's section 3: Generator, *proposed* capacity data is used. Table C.10 in the Online Appendix reports the summary of *proposed* gas power plants in the New England electricity market (ISO-NE), from year 2013 to 2019.

Case	Which firm installs new gas generation capacity?	Size of the new capacity installed (industry level)	Firm scale change
(1)	small fringe suppliers (entrants)	= total retired capacity	retired firm (↓), others (–)
(2)	retired firms (incumbent)	> total retired capacity	retired firm (↑), others (–)
(3)	firms not operating the retired generation (incumbent)	= total retired capacity	retired firm (nuclear plant owner: ↓, coal plant owner: –), others (↑)

Notes: Note that *retired* firms refers to strategic firms that used to operate the retired baseload generation. The size of the new capacity installed shown in the second column refers to the accumulated sum of capacities of new gas generators installed in each counterfactual scenario. *Firm scale* column shows whether or not the scale of firms have increased (↑), decreased (↓) or unchanged (–) after the retirement.

Table 8: Description of Capacity Installation Counterfactual Cases

no entry by the small fringe suppliers. Third, some firms convert the site of the retired coal power plant into a new gas generation facility, indicating that re-using the infrastructure (e.g., transmission lines) and facilities of the retired power plant may be economical for firms, and also for the grid.[64] Although these installation patterns coexist currently, I isolate elements from each to design the counterfactual scenarios.

Additional industry structures to simulate I examine the impact of transition on market power under three additional counterfactual cases that differ in how the retired coal plant is marginally replaced by the new gas power plant. Each case is designed to incorporate some features of the actual capacity installations observed from data. Additionally, the cases considered are designed to better identify the underlying forces leading to a change in competition relative to the baseline case. The firm scale, capacity and the number of firms change as I allow for different ways of installing new capacity, as summarized in Table 8.

In Case (1), hypothetical fringe suppliers enter the industry with new gas power plants, replacing the total capacity of the retired baseload generation. Although this scenario differs from the actual trend, it serves as a benchmark for a competitive path of transition. Each fringe plant has a capacity of one of the following, $q_{i,\text{fringe}} = \{50, 80, 100\}$ MW, thereby introducing about 50 new fringe suppliers to the industry.[65] The marginal cost of these new gas power plants is generated using the gas price index data and the heat rate information of the most up-to-date gas turbine technology, similar to how I constructed the marginal cost of a hypothetical gas power plant in the baseline case.[66] Because fringe

[64] This makes the baseline case assumption fairly realistic. However, new gas plants are likely to have larger capacity than the retired coal plants due to much lower fixed and capital costs – \$650/kW for combined cycle gas versus \$5,212/kW for coal (U.S. Energy Information Administration 2019).

[65] The capacity sizes are chosen based on actual capacities of fringe power plants that enter the New England grid (*source*: EIA-860).

[66] To avoid having a flat region in the residual demand curve, I randomly perturbed the marginal cost values of these power

suppliers are not strategic players, they affect the market outcome only through a change in the residual demand curve faced by strategic firms. Therefore, the slope (β_{th}) of the new residual demand curve – after adding the hypothetical fringe firms – must be re-estimated. See Online Appendix C.6 for the estimation details.

Case (2) is similar to the baseline case, as it allows the retired baseload generation to be replaced by the same operating firm (i.e., the *retired* firm). However, it differs from the baseline case in that the newly installed gas generation has a capacity 50% greater than that of the retired plant.[67] As a result, both the capacity of firms that previously operated the retired baseload plants and the overall industry capacity increase.

In Case (3), I allow large incumbent firms that *do not* operate any of the retired baseload generation (i.e., firms other than the *retired* firms) to expand the capacity of their existing gas generation. Specifically, approximately 400 MW of additional gas generation capacity (hypothetical gas power plants) is allocated to each incumbent strategic firm, starting with the largest gas-intensive firm.[68] The capacity added by these firms matches the retired nuclear generation capacity but does not include the capacity of the retired coal plants.[69] Each retired coal plant is instead replaced by the same firm that operated it, using a new gas power plant with equivalent capacity.

Results Figure 10 summarizes the average values of the change in market power ($\Delta\Delta P_{th}$) for each of the counterfactual scenarios. A more detailed summary of these values can be found in Table B.3 in the Appendix. In Panel (a) of Figure 10, the average value is plotted across different demand levels (D1 to D4) and Panel (b) shows the average value plotted across different gas price levels (G1-low to G3-high).[70] The graph overlays the results of each counterfactual scenario with the baseline results to provide a clearer comparison across cases.

The most pro-competitive scenario is Case (1), where the industry becomes significantly more fragmented after the transition. The average $\Delta\Delta P_{th}$ is \$-2.7/MWh, indicating that market power even decreases post-transition (see Table B.3). The pattern of $\Delta\Delta P_{th}$ also differs from the baseline case. As shown

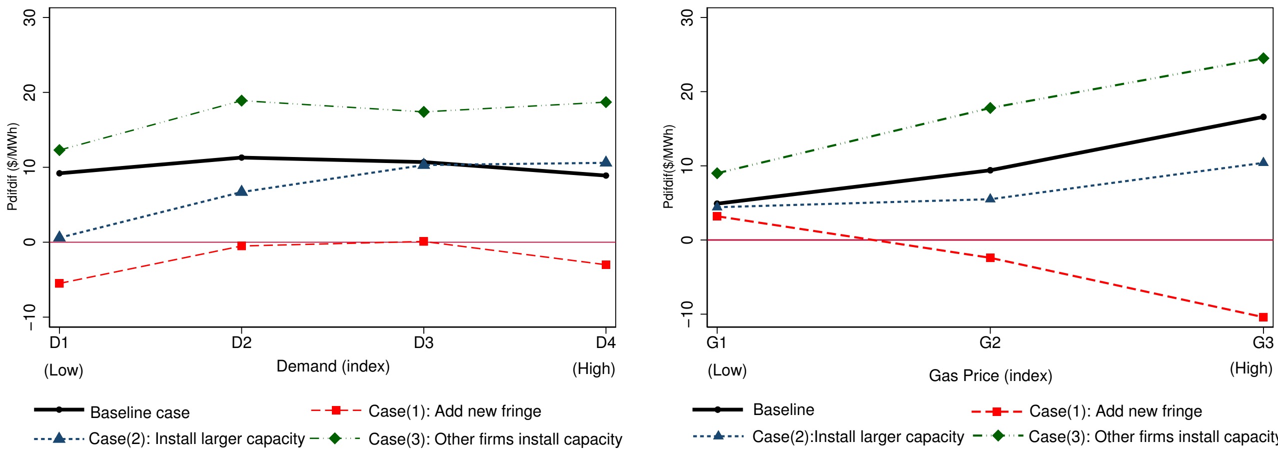
plants between 80 to 120% of the representative marginal cost.

[67] The 50% capacity expansion is consistent with the observed rate of expansion by retired firms in the data (EIA-860).

[68] When allocating additional capacity, large-scale gas-intensive firms were prioritized. The 400 MW capacity added to the hypothetical power plant is based on the average capacity of proposed natural gas generation (source: EIA-860). The marginal cost for the hypothetical plant was constructed similarly to the baseline simulation.

[69] This approach is practically motivated: the number of strategic incumbent firms receiving additional gas capacity is small relative to the total retired capacity, which includes both coal and nuclear retirements.

[70] In Panel (a), gas price differences are not controlled for within each demand bin, and in Panel (b), demand differences are not controlled for within each gas price bin. A full summary of average $\Delta\Delta P$ values that controls for both demand and gas price levels is provided in Table B.3 in the Appendix.



(a) Averaged Over Demand

(b) Averaged Over Gas Price Shock

Notes: The average change in market power, $\Delta\Delta P_{th}$, is displayed across demand (panel (a)) and gas price (panel (b)). The results for three additional cases are plotted together with the baseline case, which is displayed in a bold line. Case (1) is when adding new fringe, Case (2) is when the retired firm installs a larger capacity than the retired generation, and Case (3) is when other firms (non-retired firms) install capacity (green, dash-dot line, diamond marker). The demand index represents demand bins from D1 (lowest) to D4 (highest), and the Gas Price index denotes categories G1(low), G2(medium), and G3(high). These indices were previously used when reporting the results for the baseline case.

Figure 10: Summary of $\Delta\Delta P_{th}$ of Capacity Counterfactuals

in the Case (1) plot in Panel (a), market power increases the least in lower-demand hours (D1), in contrast to the baseline case. Importantly, market power decreases further as gas prices increase, as shown by a decreasing path of the Case (1) plot in Panel (b). Adding fringe suppliers to the industry, as in Case (1), restrains strategic firms' market power by making residual demand significantly more elastic (β_{th} increases by about 50%, on average), particularly on higher gas price days when residual demand was more inelastic before the adjustment.[71] As a result, the adverse effects found in the baseline case are mitigated, even on days hit by large gas price shocks.

In Case (2), where retired firms add larger gas generation capacity to replace their own retired plants, the overall increase in market power is greater than under fringe entry (Case (1)) but smaller than in the baseline case; the average $\Delta\Delta P_{th}$ is \$6.5/MWh. When examining the pattern across demand, I find that market power increases less than the baseline case during lower-demand hours (D1-D2), though it increases slightly more during high-demand periods (D4), as shown in Panel (a) of Figure 10.[72] Notably, market power also increases less than the baseline case with rising gas prices; the slope of the Case (2) plot in Panel (b) is flatter than in the baseline case. These patterns are explained as follows: allowing retired firms to install larger capacity makes their supply marginally more price-responsive (i.e., more

[71] See Online Appendix C.6 for a detailed summary of the new slope estimates (β_{th}).

[72] Market power increases in D4 because a higher proportion of *retired* firms are identified as withholding firms during the highest demand hours (D4) in the baseline case. Therefore, increasing the scale of retired firms beyond the baseline level – as in Case (2) – leads to an even greater increase in market power within this demand range. Note that retired firms operate not only baseload units but also gas- and oil-fired units that are used during high-demand hours.

elastic) than in the baseline case. This implies that the residual demand faced by *competitors* of the retired firms – primarily the large gas-intensive firms identified as major withholders – becomes more elastic. As a result, the gas-intensive firms – identified as the main withholders in the baseline case – are less able to exercise market power.

In Case (3), where gas-intensive incumbent firms install new gas generation, the overall increase in market power is higher than that of all other counterfactual cases, even exceeding the baseline case; the average $\Delta\Delta P$ is \$16.4/MWh. This pattern holds across all demand and gas price levels, with the Case (3) plots in Panel (a) and (b) consistently above the plots of other cases. Moreover, market power increases further as the gas price increases, shown by the steep increasing path of the Case (3) plot in Panel (b). The reason market power increases the most after in Case (3) is as follows. These firms – the large gas-intensive ones – are identified as exercising relatively greater market power throughout the transition in the baseline case. Allowing them to expand their gas generation capacity effectively scales up already dominant firms, leading to even greater market power in the baseline case. At the same time, the scale of the retired firms – which would compete with these gas-intensive firms – decreases, further reinforcing the dominant position of the large gas-intensive firms.

The results of this capacity counterfactual analysis have policy implications given that the ongoing capacity installations in the New England grid is far from the ideal situation (e.g., fringe entry) and instead, often involve the capacity expansion of large-scale incumbent firms that have the potential to exert market power. Some retired firms appear to replace their own generation with larger gas power plants (as in Case (2)), whereas a more common form of installation involves other incumbent firms, already heavily concentrated on gas generation, expanding their existing facilities.[73]

Therefore, the results highlight the importance of properly incentivizing the replacement (installation) of capacity following retirement, based on a careful consideration of the change in strategic interactions between firms upon transition. Although Case (1) may not be entirely realistic, it demonstrates a pro-competitive outcome and highlights the need to investigate potential barriers or disincentives that could discourage small-scale entries into the industry. Surprisingly. there has been limited attention given to this important aspect of the transition; how firm characteristics and industry concentration may change throughout the process. The question of how market authorities can effectively incentivize capacity entries to guide the industry toward a smoother transition path remains a subject for future

[73]However, the current observations are insufficient to definitively determine the direction of capacity installations, as they reflect a mix of the cases considered in the analysis.

research.

8 Conclusion

An increasing number of baseload coal and nuclear power plants are retiring from the grid, and the U.S. wholesale electricity industry is undergoing a major transition towards cleaner natural gas and renewable energy. Most of the discussions regarding the transition centers around the environmental benefits or concerns over the reliable supply of energy following the transition. This study highlights the importance of considering the impact of this transition on market competition, focusing on the volatile input cost of cleaner energy. That is, the costs associated with generating electricity with gas or renewables are low but could substantially increase depending on fuel market conditions or the weather. This feature differentiates the clean energy from the traditional baseloads characterized by having low and stable input costs. What will market competition be like if the cost of clean energy sources increases again in an industry that has already transformed into using proportionally more of these energy sources? Will the change in industry structure – shaped by how clean generation replaces retired capacity – also affect competition? A comprehensive cost-benefit analysis of transitioning to cleaner energy requires understanding how such a transition affects firms' strategic incentives and reshapes the industry structure.

I study this question in the context of New England wholesale electricity market which is awaiting retirements of major coal and nuclear power plants, despite having volatile gas prices. With a counterfactual analysis based on the model of quantity competition, I show that market power increases after the transition, especially more so when gas prices are higher. However, the expected market power increase can be mitigated if the new capacities are installed in a way to make the industry more fragmented or to curb the scale expansion of incumbent firms that are gas-intensive in their generation. The result, therefore, emphasizes the importance of a well-planned transition towards cleaner energy, which comes through a carefully incentivized installations of new capacities, as means of keeping the market competitive even under the increased exposure to the cost volatility.

Although these findings have strong policy implications, it is worth mentioning that the results presented here is an upper bound of the likely outcome, and that the equilibrium computation would differ from the complicated market-clearing process employed by system operators (ISO), which fully accounts for transmission congestion. Nonetheless, the primary goal of this study is to understand firm's changing incentives and market conditions that contribute to these changes, in order to offer policy guidance to regulators.

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Appendix

A Estimation and Key Parameters

A.1 Optimal Bidding Model

The following model describes the bidding decisions of an electricity-generating firm competing in a multi-unit uniform auction (Kim 2022; Reguant 2014). Suppose there are $i = \{1, \ldots, N\}$ firms that each operates J_i number of units, indexed by $j = \{1, \ldots, J_i\}$, that can generate electricity using multiple energy sources. In the daily auction, a firm submits hourly price bids (b) and quantity bids (q) – which consist of multiple steps (k) of bids – for each of its generating units. Therefore, the k^{th} step of a bid submitted for firm i's unit j in the auction held at hour h of day t is $\mathrm{b}_{ijkht} =< b_{ijkht}, q_{ijkht} >$. Given the market clearing price P_{ht}, the (ex-post) profit function of firm i in the hourly auction (ht) is shown below:

$$\pi_{iht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) = \; P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) \; \left(Q_{iht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht})) \; - \nu_{iht} \;\right) \; - \sum_{j=1}^{J_i} C_{ijt}(\; q_{ijht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht})) \;) \tag{A.1}$$

The main idea behind the estimation is that the equilibrium bids submitted by firms – observed in the data – maximize their expected profits. From this, we derive the first-order condition shown in Equation (A.2), which is used to estimate the parameters.

$$\mathbb{E}_{-it} \left[\frac{\partial P_{ht}}{\partial b_{ijkht}} \; [\; (Q_{iht}(P_{ht}) - \nu_{iht}) \; + \; (b_{ijkht} - \; C^{'}_{ijt}) \; \frac{\partial RD_{iht}}{\partial P_{ht}} \;] \; \right] = 0 \tag{A.2}$$

The empirical analogue of the first-order condition is shown in Equation (A.3), which includes an expectation over the bids of other firms ($\mathbf{b}_{-it}$) that are uncertain to firm i. Further details of the estimation procedure are provided in Kim (2022).

$$m_{ijkht}(\theta \; ; S) = \frac{1}{S} \sum_{s=1}^{S} \frac{\partial \widehat{P^{s}_{ht}}}{\partial b_{ijkht}} \Big(\; (Q^{s}_{iht} - \nu_{iht}(\gamma_{ih}) \;) \; + \; (b_{ijkht} - mc_{ijt} \;) \; \frac{\partial \widehat{RD^{s}_{iht}}}{\partial P_{ht}} \Big) \tag{A.3}$$

A.2 Marginal Cost Estimation

A common practice in electricity market studies is to measure the marginal cost of power plants using fuel price index data, which is a weighted-average of firm-level spot gas prices. However, this approach can be inaccurate when the natural gas market is illiquid and spot gas prices become volatile. In such cases, the difference between the spot price a firm actually pays and the fuel price index value widens, making the index data an inaccurate proxy for firm-level gas prices. Online Appendix C.2.1 provides additional examples where this measurement issue is more pronounced.

To address this empirical challenge, I use high-frequency bidding data to estimate the marginal cost implied by firms' bids – reflecting the opportunity cost they internalize. Specifically, I estimate the marginal cost of a generating unit j, operated by firm i, on a daily basis, denoted C'_{ijt}. The estimation uses GMM based on the empirical analogue of the firm's first-order necessary condition for profit maximization, shown in Equation (A.3). I assume the marginal cost is constant over quantity, i.e., $C'_{ijt}(q_{ijt}) = mc_{ijt} + \epsilon_{ijkht}$. Additional details on the estimation procedure are available in Kim (2022). Note that marginal costs can only be estimated for units with a positive probability of being marginal. For other units, I use bid prices as proxies for marginal costs. This is reasonable because firms typically bid their marginal costs for units that are unlikely to affect market prices, as these units cannot be used strategically.

The marginal cost of hypothetical gas power plants is measured as follows. The marginal cost consists of two components: fuel cost and emissions cost. The fuel cost is calculated by multiplying the assumed heat rate of 7 MMBtu/MWh by the fuel price index. The emissions cost is calculated by multiplying the assumed heat rate by the emissions factor for natural gas, as reported by the EPA, and by the emissions permit (RGGI) prices during the sample period, also reported by the EPA.[1] The heat rate of 7 MMBtu/MWh is chosen based on several web page sources reporting the new combined-cycle unit's base heat rate.[2]

A.3 Startup cost and ramping cost

Startup costs and ramping costs This study abstracts from fixed costs, as modeling and estimating fixed costs would require a dynamic framework, which is incompatible with the static model employed here. However, the equilibrium differences I measure between the pre-and post-transition samples are not affected by this omission, because both equilibria are computed under a model that excludes fixed costs. Omitting fixed costs becomes problematic primarily when market power is assessed by comparing actual market outcomes (which are influenced by fixed costs) to counterfactuals computed without them (Reguant, 2014).

Although I do not explicitly model ramping costs, I incorporate a proxy using information revealed in coal plant bids. A price bid submitted by a coal power plant typically consists of a component reflecting marginal operating costs and another capturing ramping costs. These ramping-cost bids can be identified by examining the bid data and their assigned probability weights in marginal cost estimation

[1] Emissions factor table can be found in the following link. https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

[2] For example, see https://www.transmissionhub.com/articles/2016/05/hawaiian-electrics-kahe-project-to-consist-of-three-ge-combustion-turbines.html

($\partial p/\partial b$, the probability of being marginal). I include the price-quantity pairs of these higher-step bids in the cost function, treating them as if they represent a separate generating unit within the coal plant. Nevertheless, this approach is only a proxy and does not fully capture true ramping costs.

Cases in which omitting startup cost or ramping cost could be problematic During very low-demand hours (e.g., 2 AM), a power plant with high fixed costs may continue generating electricity at a price below marginal cost, anticipating it will operate later when prices exceed marginal cost and the earlier losses can be recouped. Because the plant is already online, shutting down and restarting after a few hours would be inefficient. Thus, operating below marginal cost in these hours reflects fixed-cost considerations and dynamic decision-making.

A second case arises when demand or supply changes discountinously during regular operating hours. If the demand spikes, a firm may be unable to ramp up quickly and continue producing at the previous level. If demand drops sharply, even if it would be optimal to reduce output, high start-up costs and expectations of a demand rebound may lead the firm to maintain production. These, too, are dynamic production decisions.

Third, in the event of a sudden and significant drop in supply, generators with high ramping costs may not increase output – even if doing so would be optimal from a static perspective. Such behavior, as discussed in Jha and Leslie (2025), typically occurs in systems with high renewable penetration.

Of these, only the first scenario – production during very low hours – is relevant to my analysis. To account for this, I exclude very low-demand hours from the sample. The second scenario is unlikely in my setting, as the sample does not exhibit large, discontinuous changes in demand or supply. The third scenario is also not applicable, as renewable generation represents less than 10% of total supply in the New England grid during the study period and is therefore excluded from the analysis.

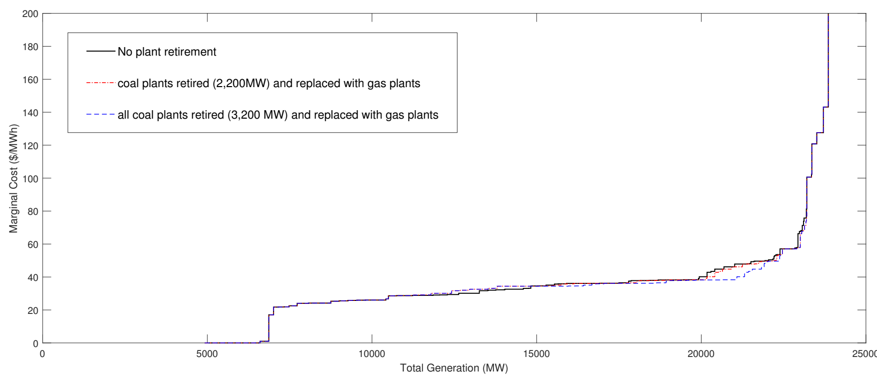
Although I exclude hours in which fixed costs are most influential, dynamic considerations may still affect firms' supply decisions. Potential biases in market power assessment from excluding fixed costs are discussed in Online Appendix C.2.2.

A.4 Strategic firm selection procedure

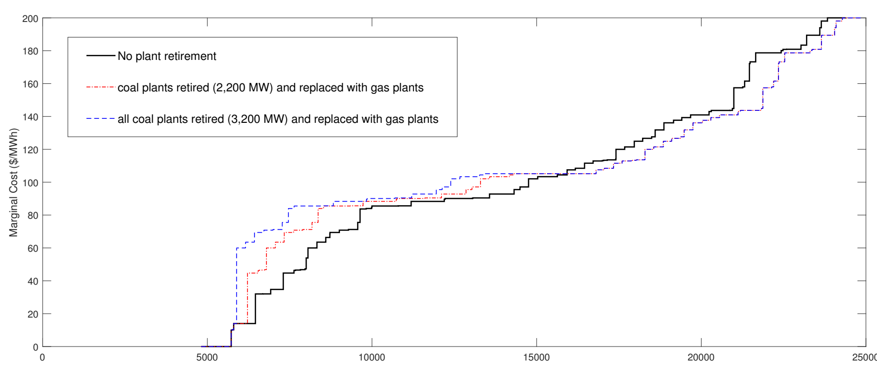
For each market (t, h) in the pre-retirement sample, I compute the competitive quantity at the firm level and compare it to the firm's actual observed quantity. I select firms whose observed quantity is at least 5% smaller than the counterfactual competitive quantity and differs by more than 50 MW in absolute terms are classified as *strategic*. Firms not meeting this criterion are categorized as *non-strategic*, which includes not only small, single-plant operators but also large firms unable to position their units close to the market-clearing point.

Although the selection of firms is based on observed behavior in the pre-retirement market, the market environment may change after the counterfactual adjustment. To address this, I also identify firms that were not strategic pre-retirement but could become so under the counterfactual (e.g., by operating generators that could become marginal). Specifically, for some large-share firms that did not meet the first selection criterion, I examine whether they operate generators in an expanded marginal set – defined as generators with marginal costs within ±20 MW of the equilibrium price, or located within ±1,000 MW of the market clearing point on the supply curve. If such firms also have sufficient residual capacity (at least 10% of their total capacity within this range), I classify them as strategic in the counterfactual setting. Further discussion on the strategic firm selection can be found in Online Appendix C.5.

B Additional Tables and Figures



(a) Normal Day (No Gas Price Shock): Gas Price =$4/MMBtu



(b) Day with Gas Price Shock: Gas Price = $15/MMBtu

Notes: The graph is generated with the generator-specific marginal costs. The original curve is indicated as "No plant retirement". In the "plant retirement" situation, the retired coal power plant is replaced with a hypothetical gas power plant of the same capacity. Red dash-dot line shows the case where a total of 2,200 MW of coal generation retires, and the blue dash line shows where a total of 3,200 MW of coal generation retires.

Figure B.1: The effect of the transition on the industry-level marginal cost curve

		Demand (GW)			
		Low Demand		⇒	High Demand
	Total	(D1)	(D2)	(D3)	(D4)
mean	15.785	11.665	14.819	16.289	18.752
med	16.057	11.873	14.826	16.297	18.372
s.d.	2.958	1.632	0.459	0.536	1.385
min.	8.107	8.107	14.073	15.500	17.022
max.	22.776	13.978	15.477	16.996	22.776
N	348	83	61	83	121

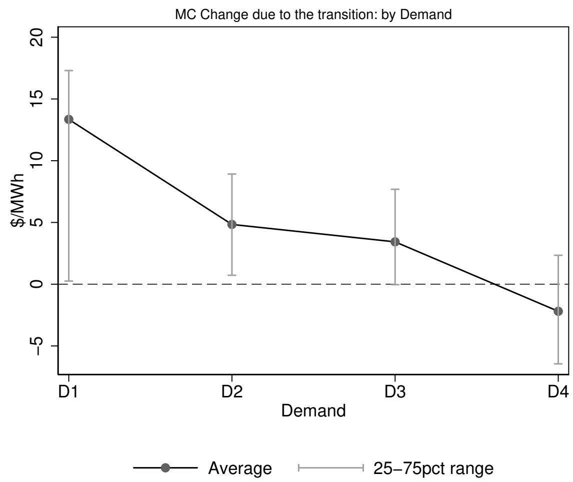
Notes: (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same.

Table B.1: Summary statistics: aggregate demand

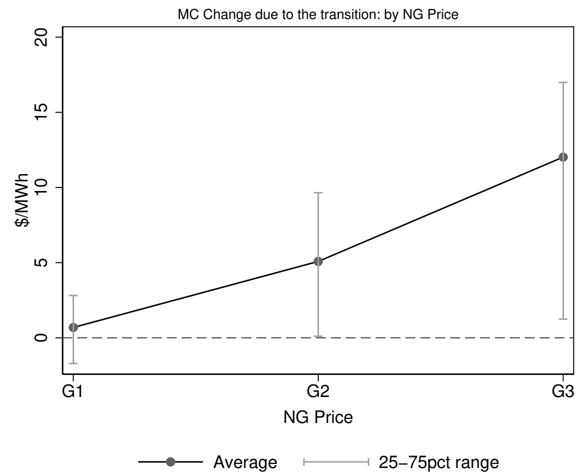
	Baseline $\Delta\Delta P_{th}$	Case (1) $\Delta\Delta P_{th}$	Case (2) $\Delta\Delta P_{th}$	Case (3) $\Delta\Delta P_{th}$
Demand	-0.07	0.85^{***}	1.62^{***}	0.98^{***}
	(0.17)	(0.19)	(0.24)	(0.24)
Gas price	0.81^{***}	-1.15^{***}	0.38^{**}	1.04^{***}
	(0.08)	(0.09)	(0.12)	(0.12)
constant	9.85^{***}	-2.68^{***}	6.54^{***}	16.5^{***}
	(0.52)	(0.59)	(0.74)	(0.73)

Notes: Market level $\Delta\Delta P_{th}$ values are regressed on the demand and gas price levels of the market. Each column shows the resgression result of $\Delta\Delta P_{th}$ obtained under different counterfactual scenarios. CF(1), CF(2), and CF(3) refer to the additional capacity counterfactuals examined in Section 7, and RN(1) and RN(3) are renewables counterfactual examined in Appendix C.7. *Demand* is the aggregate market demand of the day t-hour h market (*unit*: GWh). *Gas price* is the spot gas price index of day t (*unit*:$/MMBtu). Both variables are demeaned. Standard errors in the parenthesis. N = 348.

Table B.2: Regression of $\Delta\Delta P_{th}$: patterns over demand and gas Price



(a) ΔMC mean$_{th}$: by demand



(b) ΔMC mean$_{th}$: by NG price

Notes: ΔMC mean$_{th}$ is the difference between the market level average marginal costs of strategic firms before and after the transition, i.e., $\overline{MC}_{th,post} - \overline{MC}_{th,pre}$ (unit: \$/MW). A *positive* value indicates an *increase* in the average marginal costs after the transition. The graph plots the average (shown in dots) and the distribution (25-75 quantiles, shown in bars) of ΔMC mean$_{th}$ taken within each sample.

Figure B.2: Average change in the marginal cost of strategic firms due to the transition

	CF	Total	$\Delta\Delta P_{th}$ Low Demand (D1)	(D2)	⇒ (D3)	High Demand (D4)
$\Delta\Delta P$	(*)	9.8	9.2	11.3	10.7	8.9
	(1)	−2.7	−5.5	−0.5	0.1	−3.1
	(2)	6.5	0.6	6.7	10.3	10.6
	(3)	16.4	12.3	18.9	17.4	18.7
Further Controlling for the Daily Gas Prices						
(G1 - Low)						
$\Delta\Delta P_{th}$	(*)	4.9	5.4	1.6	5.0	6.4
	(1)	3.2	1.1	1.3	1.9	7.9
	(2)	4.4	4.2	−0.1	2.5	9.8
	(3)	9.0	9.9	5.7	6.4	12.6
(G2 - Med)						
$\Delta\Delta P_{th}$	(*)	9.4	8.4	9.6	10.8	8.9
	(1)	−2.4	−6.2	0.3	0.2	−0.6
	(2)	5.5	−2.5	7.8	10.7	12.2
	(3)	17.8	10.7	24.6	21.2	21.2
(G3 - High)						
$\Delta\Delta P_{th}$	(*)	16.6	16.1	23.4	21.9	11.5
	(1)	−10.4	−14.5	−3.4	−2.9	−15.5
	(2)	10.4	0.07	14.2	21.1	10.5
	(3)	24.5	18.2	31.0	26.5	23.6

Notes: Table summarizes the mean of $\Delta\Delta P_{th}$ within each demand-gas price bin (D-G). Each row presents the results from different capacity installation scenarios: baseline case (*), Case (1): add new fringe, Case (2): retired firms installing larger capacity, and Case (3): expand incumbent's capacity. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: days with gas prices between \$4 to \$9/MMBtu (G1 - Low), between \$9 and \$15/MMBtu (G2 - Med), and above \$15/MMBtu and up to \$27/MMBtu (G3 - High). As we selected days only among those with daily gas prices above the normal level of \$4/MMBtu, even the "Low Gas Price" category includes the sample days with gas prices higher than the normal (lowest) level. N = 348.

Table B.3: Price difference, $\Delta\Delta P_{th}$: capacity installation counterfactuals

C Online Appendix (Not for Publication)

C.1 Cournot Model

Firm i's profit maximizing problem is shown below:

$$\mathcal{L}_i \equiv \pi_{it} + \lambda_{it}(q_{i,max} - q_{it})$$

$$\frac{\partial \mathcal{L}_i}{\partial q_{it}} = \frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \leq 0, \quad q_{it} \geq 0, \quad \frac{\partial \mathcal{L}_i}{\partial q_{it}}\, q_{it} = 0 \tag{C.1}$$

$$\frac{\partial \mathcal{L}_i}{\partial \lambda_{it}} = q_{i,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0, \quad \frac{\partial \mathcal{L}_i}{\partial \lambda_{it}}\, \lambda_{it} = 0 \tag{C.2}$$

We can rewrite equations (C.1) and (C.2) by plugging in the actual specifications, which are shown below in equations (C.1a) and (C.2a):

$$\frac{\partial p_t}{\partial q_{it}}\,[q_{it} - q^f_{it}] + p_t - C'(q_{it}) - \lambda_{it} \leq 0, \;\; q_{it} \geq 0, \;\; \frac{\partial p_t}{\partial q_{it}}\,[q_{it} - q^f_{it}] + p_t - C'(q_{it}) - \lambda_{it}\; q_{it} = 0 \tag{C.1a}$$

$$q_{i,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0 \quad (q_{i,max} - q_{it})\, \lambda_{it} = 0 \tag{C.2a}$$

As the derived conditions become a mixed complementarity problem (MCP), I rewrite these using complementarity symbols:

$$\begin{aligned} \frac{\partial p_t}{\partial q_{it}}\,[q_{it} - q^f_{it}] \;+\; p_t \;-\; C'(q_{it}) \;-\; \lambda_{it} \leq 0 \;\;\perp\;\; q_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s \\ q_{i,max} \;-\; q_{it} \geq 0 \;\;\perp\;\; \lambda_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s \end{aligned} \tag{C.3}$$

These complementarity conditions are similar to those derived in Bushnell et al. (2008).[1] The Cournot equilibrium quantities, $\mathbf{q}^*_t = [q^*_{1t}, \ldots, q^*_{Nt}]$, is the set of firm-specific quantities that simultaneously solves the system of complementarity conditions. That is, we stack the first-order conditions, shown in (C.3), for all strategic firms, and then numerically solve a vector of quantities of strategic firms that satisfies the entire system of conditions. To obtain the solution, we use PATH algorithm, which is effective in solving the mixed complementarity problem (Kolstad and Mathiesen 1991; Ferris and Munson

[1] These conditions can be converted into a new form by removing the multiplier λ_{it} from the equations. Details can be found in the Online Appendix.

1998).[2] Once we find the equilibrium quantities, the market price can be obtained by plugging these values into the residual demand curve in Equation (2).

Mixed Complementarity Problem The Bushnell et al. (2008) version of the mixed linear complementarity problem (MCP) can be re-arranged into a more compact expression. The original expressions are as follows:

$$\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \leq 0, \quad q_{it} \geq 0, \quad \Big(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\Big) q_{it} = 0 \tag{C.4}$$

$$q_{it,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0, \quad (q_{it,max} - q_{it})\lambda_{it} = 0 \tag{C.5}$$

First, if $q_{it} \in (0, q_{it,max})$, $\left(\frac{\partial \pi_i}{\partial q_{it}} - \lambda_{it}\right) = 0$ is implied by the third condition of equation (C.4) because $q_{it} > 0$. Also, because $q_{it,max} - q_{it} > 0$, $\lambda_{it} = 0$ is implied by the third condition of equation (C.5). Thus, $\frac{\partial \pi_{it}}{\partial q_{it}} = \lambda_{it} = 0$ holds as $\left(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\right) = 0$.

Second, if $q_{it} = q_{it,max}$, then $\lambda_{it} \geq 0$ from the third expression of equation (C.5), and because $q_{it} > 0$, it must be that $\left(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\right) = 0$ from the third condition of equation (C.4). Therefore, $\frac{\partial \pi_{it}}{\partial q_{it}} = \lambda_{it} \geq 0$ holds.

Finally, if $q_{it} = 0$, then $q_{it,max} - q_{it} > 0$ unless $q_{it,max}$ is zero which is not the case. Therefore, $\lambda_{it} = 0$ from the last condition of equation (C.5). And because $\frac{\partial \pi_{it}}{\partial q_{it}} \leq \lambda_{it}$ holds as implied by the first condition of equation (C.4), $\frac{\partial \pi_{it}}{\partial q_{it}} \leq \lambda_{it} = 0$ holds.

As a result, we have an expression for mixed complementarity problem (MCP):

$$\begin{aligned}
&\text{For } \ \forall i \in \mathcal{F} \\
&\qquad 0 < q_{it} < q_{i,max} \quad \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} = 0 \\
&\qquad q_{it} = 0 \qquad\qquad\quad\ \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} \leq 0 \\
&\qquad q_{it} = q_{i,max} \qquad\quad \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} \geq 0
\end{aligned} \tag{C.6}$$

This matches the standard specification of MCP problem. Three pieces of data are necessary which are the upper bounds u, lower bounds l and the function F. The general form of MCP problem is described as below:[3]

(MCP) Given lower bounds l, upper bounds u and a function $F : R^n \to R^n$, find $z \in R^n$ such that

[2] This simulation method has been used in other research including Borenstein and Bushnell (1999), Bushnell et al. (2008), Ito and Reguant (2016), Brown and Eckert (2017), Bahn et al. (2021) and etc.

[3] Descriptions are taken from Ferris and Munson (1998).

precisely one of the following holds for each $i \in \{1, \dots, n\}$:

$$\begin{aligned} F_i(z) = 0 &\quad \text{and} \quad l_i \leq z_i \leq u_i \\ F_i(z) > 0 &\quad \text{and} \quad z_i = l_i \\ F_i(z) < 0 &\quad \text{and} \quad z_i = u_i \end{aligned} \tag{C.7}$$

Therefore, the function F that enters the PATH solver must be $-\frac{\partial \pi_{it}}{\partial q_{it}}$.

C.2 Costs

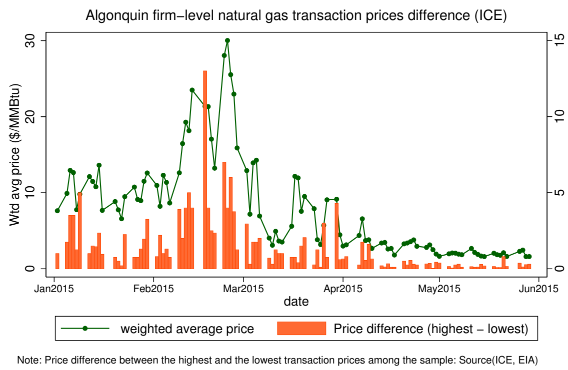
C.2.1 Marginal Cost Dispersion

This section discusses the reasons why the dispersion in marginal costs among natural gas power plants increases, especially more so as the intensity of the natural gas price shock (degree of pipeline congestion) increases.[4] This also explains why the residual demand curve (non-strategic supply) becomes more inelastic as the natural gas price further increases. That is, the residual demand curve is generated from the supply bids of power plants owned by non-strategic suppliers, most of which are gas-fired plants. And as the bids submitted by non-strategic firms would be close to marginal cost, the residual demand elasticity is closely related to the marginal cost dispersion. Additionally, the sources discussed here explain why the measurement error arises when using the index gas price data to measure the marginal cost of gas power plants, which justifies estimating the marginal costs instead of measuring them using the data.

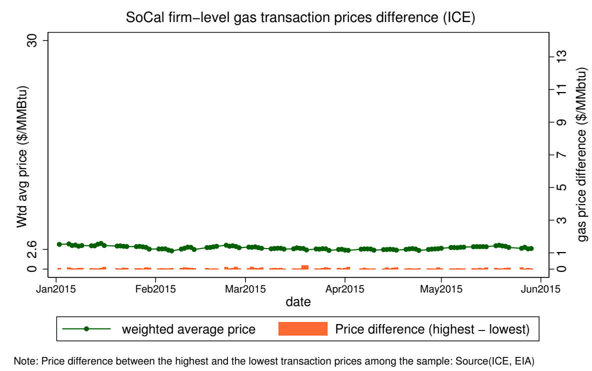
First, some of the gas-fired units are equipped with dual generation technology that enables the generation of electricity with fuels other than gas, called *dual* gas units. For example, more than 28 percent of gas generators in New England were dual units (as of 2014). As these generators can switch to using oil when the gas price increases substantially, the cost of a dual gas unit increases by less than that of a non-dual gas unit, especially on days with a large shock. The marginal cost measured for these dual units without identifying their switch decisions –which are difficult to observe – could significantly mismeasure their costs.

Second, firms can purchase gas from two different channels (i) from the daily spot gas market, or (ii) through a long-term contract with a gas supplier. Firms that enter into a long-term contract with gas suppliers can secure gas at the contracted price. Unlike spot gas prices that change every day and moment based on the gas market condition, the pre-committed contracted price is not affected by day-to-day spot gas market conditions. Therefore, especially on days with severe gas price shocks, the cost difference between gas units that purchase gas via a long-term contract and those buying from the spot

[4] The increase in dispersion of gas-fired generators' marginal costs has been documented in Figure 5 as well.



(a) Algonquin city gate



(b) SoCal city gate

Notes: Data source is over-the-counter individual transaction-level gas spot prices at two city gate points, provided by Intercontinental Exchange (ICE). The line in the figure shows the weighted average values of transaction-level gas prices, and the bars show the difference between the highest and the lowest among transaction-level gas prices. Only the subset of transactions is available as data.

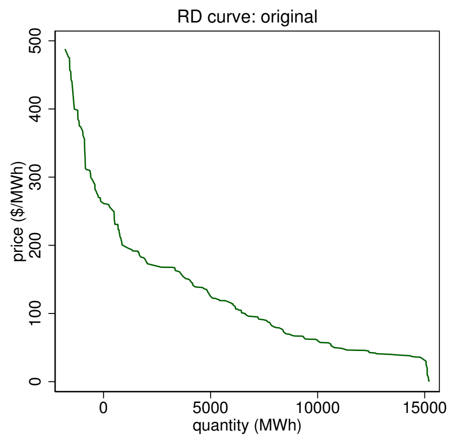
Figure C.1: Over-the-Counter Gas Spot Prices: Year 2015

market could be substantial.

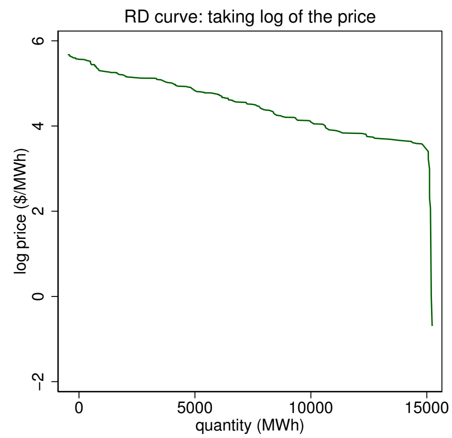
Third, when the spot gas market is under shock (caused by severe pipeline congestion), the gas spot prices vary throughout the day by fluctuating over time, even within a single day. Because the timing of gas procurement differs across firms, significant fluctuations in spot gas prices over time results in differing firm- and unit-level gas prices. Figure C.1 depicts a substantial cross-sectional differences in firm-specific spot gas prices in New England area experiencing the gas price shock. In this case, the gas price index data (which is a weighted-average measure) cannot accurately represent the gas price that applies to each firm, thus using index data to measure marginal cost becomes problematic.

C.2.2 Potential bias in market power assessment when excluding fixed costs

Although I exclude hours in which fixed costs are most influential, dynamic considerations may still affect firms' supply decisions even after this adjustment. If supply decisions reflect dynamic considerations involving start-up costs, the static model may introduce bias. In such cases, a *retired* firm operating a coal plant might produce more in the actual pre-retirement market than the static model predicts. This would imply a smaller degree of quantity withholding (i.e, $q_{\text{com, pre}} - q_{\text{cour, pre}}$) than estimated, leading the analysis to understate the retired firm's market power in the pre-retirement period – and thus understates the retirement's impact on its exercise of market power. Market power may be overstated during high-demand hours if marginal units face ramping costs that are not captured in the model. However, marginal units during these hours are typically gas-fired plants, which have low ramping costs. As a result, high-demand periods are less susceptible to this type of bias than low-demand hours.



(a) RD curve: original



(b) RD curve: taking log of price

Figure C.2: Residual Demand Curve: original vs. logged ($t = 97$, $h = 11$)

C.3 Residual Demand

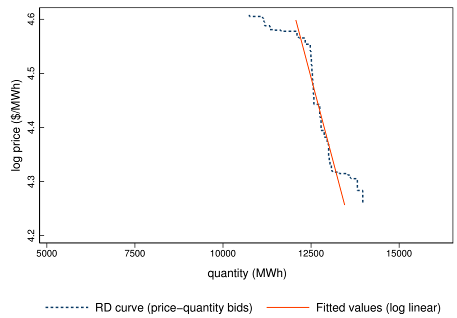
C.3.1 Assessing the fit of the residual demand estimate

I construct the residual demand curve (of strategic firms) using observed equilibrium supply bids from non-strategic firms. This curve is then fitted using a parametric log-linear demand specification (Equation (2) for use in the Cournot model. I apply a spline regression with one or two knots, selected based on the curve's shape, to fit a broader range of the curve. The same fitted curve is used in counterfactual simulations, under the assumption that non-strategic firms continue being non-strategic post-retirement, bidding their marginal costs.

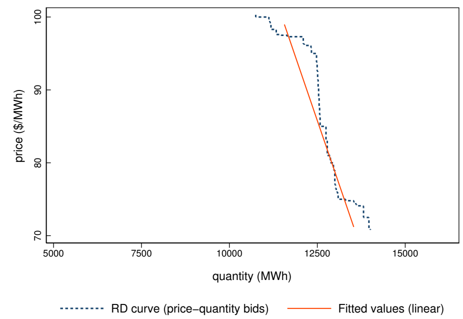
The log-linear specification follows prior literature (e.g., Bushnell et al. 2008) and is further supported by visual inspection of the original curve. Figure C.2 panel (a) shows an actual residual demand curve nonparametrically constructed from bids, $RD(p) = \overline{D} + D(p) - S(ns, p)$, and panel (b) shows the log-transformed version (taking log values to the price bids), which appears nearly linear. This supports the use of a log-linear demand function in the analysis.

The log-linear specification also outperforms other parametric forms, such as the linear specification, in terms of overall fit. The original residual demand curve contains uneven segments due to the step-like nature of bids. Applying a log transformation before fitting smooths out these irregularities and produces a more consistent fit. Figure C.3 illustrates this using a sample market $(t, h) = (383, 16)$): panel (a) shows the logged original curve with the fitted log-linear demand, while panel (b) shows the original curve with the fitted linear demand. The linear fit in panel (b) is notably steeper – implying greater elasticity – particularly when approximating the non-linear sections of the original curve.

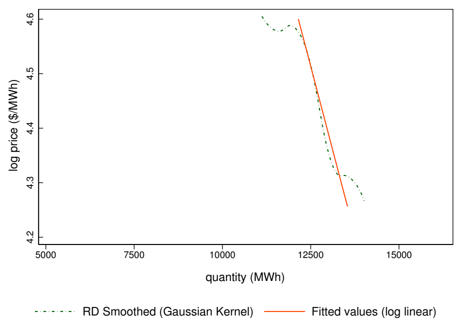
Log transforming prices also acts as a smoothing device. Panels (c) and (d) compare the fits of the log-linear and linear curves to a version smoothed using a Gaussian kernel – a standard method for



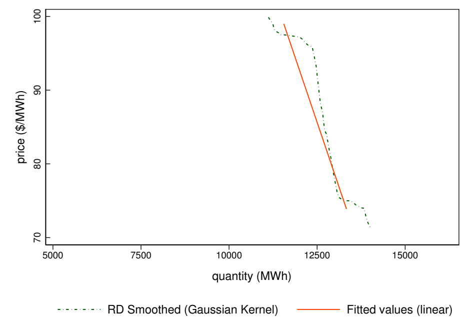
(a) Log-linear fit: $t = 383, h = 16$



(b) Linear fit: $t = 383, h = 16$



(c) Log-linear fit to kernel smoothed: $t = 383, h = 16$



(d) Linear fit to kernel smoothed: $t = 383, h = 16$

Figure C.3: RD curve: Log-linear and Linear fit comparisons

smoothing nonlinear functions. The slope of the log-linear curve in panel (c) more closely matches that of the kernel-smoothed curve (dashed line) than does the linear fit in panel (d). Although the linear specification is commonly used and fits well locally near equilibrium, the log-linear specification better captures the overall shape of the residual demand curve across a wider range – an essential feature for counterfactual analysis involving non-local equilibrium outcomes.

C.3.2 Import/export bids

I have omitted the import and export bids when nonparametrically constructing the residual demand curve. Instead, I accounted for the ex-post size of net import – net interchange – by excluding that amount from the total demand, $\bar{D}$.

Omitting these import/export bids will not critically affect the slope estimates to a great extent. First, the ISO-NE is interconnected with three balancing authorities and trades the largest amount with Hydro Quebec (HQT). New England imports electricity from HQT for most hours, nearly at full transmission capacity.[5]

Second, I confirm also from the import/export bids data (published by ISO-NE) that the net import does not respond much to price changes. In other words, the proportion of price-responsive

[5]Source: EIA-930 data. https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ISNE

import/export bids is small. Import/export bids can take two different forms: fixed-price bids and price-responsive bids. The former category of bids consists only of quantity bids with no price specified (denoted as "fixed" in the dataset), whereas the latter is submitted with price bids. As the size of the export bid is very small, I will discuss mainly about the import bids. On average, import quantities associated with the fixed-price import bids make up almost 86.5% of the total import quantity, and price-responsive bids account for less than 15%, which is only about 425 MWh in size. Even among these price-responsive bids, the portion of the bids that have price bids close to equilibrium price, which are the import bids that can potentially impact the estimation of RD slope, is very small, with an average of 30 MWh and being zero in nearly 50% of the sample.

C.3.3 Caveats: Sensitivity of RD slope to the strategic firm set

The slope of the residual demand depends on the selected set of strategic firms. This may bring concern as I use a different set of strategic firms for each market, (t, h). In this section, I will discuss the sensitivity of the RD slope estimate to the selection of strategic firm set and demonstrate that it is not a big problem in my case.

The number of strategic firms could affect the slope of the residual demand. For example, having a larger number of strategic firms makes the RD more inelastic, by construction, as fewer firms are categorized as non-strategic. However, there exists a trade-off (compromise) between strategic firm selection and RD slope. For example, including one more firm in the strategic category increases the total number of strategic firms competing in the Cournot model, which reduces overall market power, offsetting the effect of a more inelastic residual demand. Thus, having a greater number of strategic firms in a specific market, and consequently a more inelastic residual demand slope than in other markets, does not necessarily imply higher market power.

The slope of RD could also change with the composition of the firm set. For this reason, accurately selecting the set of strategic firms is important. I provide a detailed justification of the strategic firm selection in Appendix C.5. Nevertheless, the strategic firm selection is not the only determinant of the slope of residual demand. The steepness of the slope is largely driven by the overall shape of the original supply curve (merit order curve) rather than the strategic firm set. To confirm this, I re-estimated the slope of the RD curve constructed using a fixed set of strategic firms for the entire sample.[6] I was able to replicate the important pattern – RD slope becomes more inelastic with the increasing gas price levels – that contributes to finding that the impact of transition on market power increasing further with the gas price levels.

[6] I used a fixed set of eight firms having the largest scale.

C.4 Forward Contract

C.4.1 Forward contract rate estimation

It is common for electricity generating firms to engage in a forward contracting where they sell a certain amount of electricity to the demand side at a committed price (i.e., forward price) in advance of the auction. Therefore, the forward contracted quantity, q^f_{ith}, is not affected by the market price, and must be subtracted from the total quantity, q_{ith}.

I estimate q^f_{ith} within the model exploiting the method similar to Reguant (2014), due to the difficulty in obtaining data on the forward contracts.[7] I assume that firms forward contract a certain percentage, γ_{ih}, of their hourly output production and that this forward contract rate is constant over time.[8]

The estimation employs the GMM estimation based on the empirical analogue of the first-order condition of profit maximization, shown in equation (A.3). I assume that the forward contracted quantity of firm i for the hour h of the day t is, $q^f_{ith} = \gamma_{ih} q^*_{ith} + \varepsilon_{ith}$, where q^*_{ith} is the actual quantity of electricity generated by firm i in auction th, which is observed in the data. Within the model, q^*_{ith} is treated as exogenous, where the value is fixed for the given hour.[9] For a more detailed description of the estimation and identification of the parameter, please refer to Kim (2022).

C.4.2 Summary of forward contract rate estimates

Table C.7 summarizes the firm-specific hourly forward contract rates (γ_{ih}) by off-peak and peak hours.[10] The table reports estimates of 11 large strategic firms which have significant estimates of the rates. The actual range of hours categorized as off-peak and peak differ across firms, but the off-peak hours span roughly from 23 PM - 6 AM. The summary statistics are taken within off-peak and peak hours. The average rate of forward-contracting is about 75% ($\bar{\gamma} = 0.75$) during the off-peak hours and about 27% ($\bar{\gamma} = 0.27$) during the peak hours. Because the forward contracted electricity is assumed to be a certain percentage (rate) of the actual hourly production, and as the production level is higher during peak hours than in off-peak hours, it is natural to estimate a lower rate for the peak hours, by construction. Moreover, firms usually have more incentives to forward contract during off-peak hours

[7] Bushnell et al. (2008) have shown that electricity generating firms in the New England wholesale electricity market indeed enter a forward contract with the demand side. As they had access to confidential information of firm-level forward contracts, they did not estimate the forward contracted quantity in the analysis.

[8] The constant forward contract rate assumption is common in the wholesale electricity market studies, as seen in Bushnell et al. (2008) and Reguant (2014). The fact that the constant rate specification is used even in Bushnell et al. (2008), where the researchers had access to confidential information of the firm's forward contracts, gives justification to our assumption. As forward contracts derive from vertical intergration between the supply and retail companies, forward contracted quantity would have to be adjusted flexibly to the changes in retail customer demand. In this respect, it is reasonable to assume that suppliers contract a fixed *rate* of their daily generation over time, than a fixed amount, given that the total market demand from the retail sector changes every hour and day.

[9] Although q_{iht} varies as the marginal unit (j) and bid step (k) change within the model, the ex-post quantity generated by firm i, q^*_{ith}, does not vary.

[10] Hourly pattern of the cross-sectional average of the forward rates can be found in Figure C.9 in the Online Appendix.

Sample	mean	s.d.	p50	min	max	N
Offpeak	0.75	0.33	0.9	0.12	1	11
Peak	0.27	0.1	0.3	0.15	0.4	11

Notes: Off-peak hours: 23 PM - 6 AM, though the actual range of hours categorized as off-peak slightly differ across firms. Peak hours include the rest of the hours.

Table C.1: Forward contract rate of a subset of strategic firms: summarized by off-peak / peak

when both the demand and wholesale price is low. Although there is no distinctive pattern in the estimated rates across firm types, the retired firms' contracted rates are lower than others, and the rates of balanced firms are slightly higher than others during the off-peak hours.

C.4.3 How would the forward contracting incentives change after the transition?

Throughout the analysis, I fixed the forward contract rate (quantity) to the level estimated from the pre-retirement sample. However, the forward contracted rate and quantity could change in the future, adapting to the changes in the market environment caused by the energy transition.

Studies have shown that forward contracting incentives are affected by changes in market structure. Relevant research, such as Brown and Eckert (2017) and Miller and Podwol (2020), has shown that forward contracting incentives decrease following horizontal mergers. Because mergers lead to increased market power and concentration in general, their findings suggest that firms engage less in forward contracting when market concentration and market power rise.

Building upon the findings from these studies and considering my analysis, which demonstrates an overall increase in market power following the energy transition, it is expected that electricity-generating firms would have reduced incentives for engaging in forward contracting in the counterfactual environment. The reduction in forward contracting would, in turn, exacerbate the exercise of market power.

However, there are limitations when applying the findings from these studies to my empirical setting. First, the change in market structure considered in my analysis differs from that in a horizontal merger case. Second, because abnormal gas price days represent a smaller portion of the entire sample compared to normal days, forward contracting, which involves long-term commitments lasting at least a year, may not be significantly affected by the change in market power during abnormal periods. I do observe an increase in market power in this subsample after the transition; however, market power does not increase much on days when gas prices fall within the normal range, which make up a larger portion of the sample. Because firms' contracting decisions account for the market conditions throughout the entire year, the decision to adjust the contracting rate may be more influenced by market conditions during periods of normal gas prices.

I explore several other factors that may affect the forward-contracting incentives of both electricity-generating firms and retail firms, providing conjectures on how forward contracting incentives might change after the energy transition, although these conjectures are not supported by a formal equilibrium analysis.

Fixed Cost Firms are more inclined to enter into forward contracts when they operate power plants with high startup costs especially during hours when spot prices are too low. This is because the fixed cost of operating a power plant limits a firm's ability to flexibly adjust its production responding to price incentives in the spot electricity market.

As the transition involves the phase-out of high fixed-cost plants, which are subsequently replaced by low fixed-cost gas power plants, firms are expected to have reduced incentives for forward contracting after the transition. Moreover, according to the main result of my analysis, spot prices in low-demand hours are expected to increase more after the transition. This makes the spot market options more appealing than the forward market, thus reducing the incentive for forward contracts.

Heterogeneity in firms' strategic positions The change in forward contracting incentives could vary across firms, depending on their strategic positions. Firms with an increased ability to exercise market power after the transition (e.g., gas-intensive firms) may lower their forward contract rates. This is because their strategic position allows them to profitably raise prices in the spot market more than before, making the forward-contracting option less attractive. Furthermore, this type of firm will no longer face competition from conventional baseloads that oversupply during low-demand hours, which are typically the hours with the strongest incentive to contract forward. Firms that become less capable of exercising market power may also choose not to increase their contract coverage. Although these firms cannot increase spot prices themselves, they still benefit from a spot price increase resulting from market power exercised by other firms.

Price or load uncertainty Both retailers and wholesalers would be more inclined to contract forward if spot prices becomes more variable, as it allows them to secure a stable and predictable electricity procurement and revenue stream through contracting. In my case, spot prices and firm-level generation may become slightly more variable after the transition; however, the increased variability occurs only for part of the sample (about one third of the entire year). Therefore, the role of the variability factor in changing the forward contracting incentive may be relatively small.

Retailer incentive change My analysis primarily focuses on the supply side, and does not study retailers – who are on the demand side and purchase electricity either at the spot price or through forward contracts. Nevertheless, it is worth considering how their incentives for forward contracting may change after the transition.

Retailers cannot fully shield themselves from rising spot prices through forward contracts, as forward prices are typically slightly above spot prices. That is, because forward prices remain relatively stable compared to spot prices that fluctuate, retailers may end up paying more than the spot price during normal (low-cost) periods, even if they benefit during abnormal (high-cost) periods. Thus, retailers' willingness to increase forward contract positions may depend on expectations about the frequency and severity of high-cost periods after the transition.

C.5 Selecting Strategic Firms

C.5.1 How other research defines strategic firms

The conventional method of categorizing Cournot firms appears to rely on market share, firm scale or local market segmentation. The most common approach is to identify the dominant firms (typically those with large-scale operations and high market share) and model them as strategic firms. This approach has been employed in studies such as Bushnell et al. (2008), Ito and Reguant (2016), and Ryan (2021). In Bushnell et al. (2008), for instance, five major firms were used as strategic firms in the Cournot computation, although the criteria for selecting these firms were not explicitly mentioned. In Ito and Reguant (2016), the four largest players were chosen as strategic firms, reflecting the relatively concentrated structure of the Spanish electricity market. Ryan (2021) selected a total of 13 firms that accounted for over 1% of the total offered sell volume between Nov 2009 and April 2010, collectively representing a market share of approximately 70%. Ryan (2021) justified the selection of these firms by demonstrating that bids submitted by these non-strategic firms did not significantly respond to congestion (this article studies the impact of transmission congestion on market power).

This approach of categorizing firms as strategic based on their large scale or high market share implicitly assumes that the firm's capability to exert market power is strongly dependent on its size or share. Although this assumption generally holds true, it may not be perfectly applicable to my analysis, making this categorization method less suitable for my research. I will further elaborate on the reasons behind this in the following section.

Moreover, most research using a static Cournot model in electricity market settings treats the set of strategic firm as fixed. That is, these studies do not endogenize firms' decisions to behave strategically in the counterfactual simulations, instead assuming the strategic firm set is exogenous and remains fixed throughout the analysis. Typically, the firm set is not part of the counterfactual adjustments unless entry and exit are explicitly considered.

C.5.2 Why is the selection process necessary?

I select the strategic firms among the large-scale firms to refine the set of strategic firms used in the Cournot equilibrium computation. Because the electricity-generating firms compete in the multi-unit uniform auction setting, a firm has an incentive to behave strategically only when its generating unit (or power plant) has a probability of setting the price (i.e., close to being marginal). This implies that indicators such as firm size and market share are not sufficient to categorize a firm as a strategic player, as such probability varies with the market condition. For example, when the market demand is high, a large-scale firm that only operates the low-cost generators will not bid strategically, despite having a high market share, as none of its generators are close to being marginal. On the other hand, when the market demand is low, a large-scale firm that mainly operates the high-cost generators (e.g., oil-fired power plants) does not have incentives to bid strategically. If so, treating these firms as strategic players in the Cournot computation could exaggerate the strategic outcome. Furthermore, even a firm with a low market share has a strong incentive and the ability to bid strategically if several of its generators are close to being marginal under the given market condition.

To address these concerns, I select firms that are *observed* to behave strategically in the actual equilibrium (SFE), whose quantity observed from the data (generated from the SFE) considerably differs from the counterfactual *competitive* quantity of the pre-retirement sample. The selection of firms is possible because I can compute the (counterfactual) competitive quantity at the firm level in the pre-retirement sample period. The deviation of the actual quantity from the competitive benchmark indicates that the firm was making strategic production decisions under the given market conditions. The method also allows me to select a different set of strategic firms for each market, accounting for the differences in the strategic environment across markets.

C.5.3 Summary of strategic firms

Table C.2 provides a summary of market-level strategic firms. The composition of the strategic firm group (i.e., the identity of the included firms), although not reported in the table, differs across markets. As shown in Panel (A) of Table C.2, the size of the strategic firm set also varies across markets, with a median size of 9 firms. There is no strong correlation between the number of strategic firms and market demand or gas prices. A total of 20 firms appear as strategic firms throughout the sample, and their characteristics are summarized in Panel (B) of Table C.2.

	mean	med	min	max	s.d.	N
Strategic Firms						
(A) Market-level (t,h) **Sample**						
No. of firms	8.9	9	7	13	1.4	334
(B) Total Sample (18 firms)						
Total Generating Capacity (MW)						
All firms	1,272	918	415	3,372	799	20
Retired firms	1,561	1,619	712	2,295	665	4
Gas-intensive firms	1,163	779	415	3,372	988	8
Balanced firms	1,236	1,012	569	2,381	709	8
Generating Units (firm level)						
No. of units (total)	7.5	4.5	1	21	6.4	20

Notes: Panel (A) summarizes the number of firms selected as strategic firms in each market (t,h). Panel (B) summarizes the characteristics of the final list of strategic firms throughout the market sample by their type.

Table C.2: Strategic Firm Characteristics Summary

C.6 Details of the Capacity Counterfactual

C.6.1 Case (1): Adding new fringe suppliers

The total capacity of the retired baseloads (about 3,700 MW) is met by new fringe suppliers that enter with a gas-fired power plant. The capacity sum of the new power plants entering equals the total capacity of the retired baseloads. The capacity of the *retired* firms decreases as the lost capacity is not replaced. Three different capacity sizes, $\{$ 50 MW, 80 MW, 100 MW $\}$, are assigned to hypothetical power plants, leaving about 50 fringe firms to enter in each market. The capacity sizes used here are chosen based on the capacity of actual fringe power plant (single power plant entry) in New England, as observed in the EIA-860. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section A.2, but to avoid having a flat region in the supply curve, I randomly perturbed the values between 80 to 120% of the representative marginal cost, $r \in [0.8, .12]$, $\ mc_{j,t} = r\ mc_{hypo,t}$ and assigned to each hypothetical plants.

The entry of fringe suppliers affect the market outcome mainly by changing the slope of the residual demand curve (β_{th}). As the estimation of residual demand parameters relies on constructing the residual demand curve out of the actual bids submitted in the auction, I first create the hypothetical bids of these fringe firms and incorporate them into our new residual demand curve. The hypothetical bids are created using the capacity ($q_{i,fringe}$) and the marginal cost ($mc_{i,fringe}$) of fringe suppliers, exploiting the fact that non-strategic players would bid their marginal cost in the auction. The new residual demand curve after adding fringe suppliers becomes significantly more price responsive, with the slope estimate (β_{th}) increasing by about 50%, on average, and the extent of slope increase was larger on higher gas price days and in lower demand hours. Also, I re-calculated the intercept (α_{th}) by removing the production from retired generation from the total strategic quantity, Q_{st}.

The slope estimate β_{th} increased by about 49.9%, on average, after small fringe suppliers enter with new gas power plants, and the extent of slope increase was larger on higher gas price days and lower demand hours. Table C.8 and Table C.9 in the Online Appendix show how the original slope estimates and the new slope estimates changes with the aggregate demand and gas price levels of the market. The pattern is reversed in the new slopes, which is also indicated by the change in slope regression. Figure C.13 in the Online Appendix also shows an example of the new residual demand curve for two different markets.

C.6.2 Case (2): Retired firms add 50% larger gas-generation capacity

The second counterfactual is a close extension of the baseline case, where the *retired* firms now install the natural gas-fired generation having a 50% larger capacity than the one retired. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section A.2. I use the same marginal costs for all hypothetical power plants, regardless of their ownership.

In sum, capacity increases for the *retired* firms but remains unchanged for the other firms. The total capacity at the industry level is larger than in the baseline case.

C.6.3 Case (3): Other gas-intensive incumbent firms add gas generation capacity

The third counterfactual scenario is where I let the other incumbent firms, particularly the gas-intensive type of firms, to install new gas-fired generation to replace the retired baseload generation. I select three firms among the strategic firms of each market, (t, h), giving priority to the gas-intensive type.[11] These firms expand their existing gas generation capacity by installing 400 MW sized hypothetical gas-fired power plants, replacing 1,200 MW of the lost generation from the retired baseloads together. The composition of selected firms that are allocated additional capacity differs across the markets; however, two major gas-intensive firms appear most frequently. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section A.2. I use the same marginal costs for all hypothetical power plants, regardless of their ownership.

An important assumption I make here is that only the total capacity of the retired *nuclear* power generation, about 1,200 MW in total, is replaced by the incumbent firms' new gas-fired generation. In other words, the lost generation from the nuclear power plant is replaced by the new gas generation

[11] In markets where more than three gas-intensive firms exist in the strategic firm set, I selected three from the highest to lower capacities among them. Some markets only have two gas-intensive firms in the strategic firm set, in which case the last 400 MW capacity is allocated to the balanced firm. However, the strategic firms are still the majority in this case.

capacity added by the gas-intensive firms, not by the retired firms. On the other hand, the retired coal-fired generation is replaced by the *retired firm*, with a new gas power plant of the same capacity as the retired one.[12] There is a practical reason behind the assumption. If including the retired coal plants as well, the total capacity that must be replaced by incumbent firms together is too large. Given that the number of gas-intensive incumbent firms in each market is not large, it is practically infeasible to replace the generation lost from both coal and nuclear power plants.

In sum, capacity increases for the gas-intensive firms chosen for additional capacity allocation, whereas the capacity of other incumbent firms stays the same. Also, the capacity of firms operating the retired nuclear power plant decreases, whereas that of firms operating the retired coal power plant stays the same. The total capacity at the industry level does not change, the same as in the baseline case.

C.7 Renewable Generation

C.7.1 Importance of the coal to natural gas transition

I used natural gas generation as an example of the energy with a volatile input cost, and have thus considered only the transition from coal to natural gas. However, renewable generation using wind and solar has also rapidly grown over the course of years and replaced a considerable size of the retired generation capacity. It is indisputable that the electric grid should ultimately transition away from fossil fuels and towards clean renewable energy to meet the deep decarbonization goals.

Nevertheless, that does not make the transition from coal to natural gas less important. Although natural gas is a fossil fuel, it is much cleaner than coal and serves as an important bridge to clean renewable energy. Importantly, studies show that (the price drop of) natural gas played a critical role in the massive retirements of coal power generation (e.g., Linn and McCormack 2019). As long as electricity-generating firms find natural gas as a close substitute for coal, the transition from coal to natural gas may continue for a while.

C.7.2 Extension: intermittent renewable energy and the volatile marginal cost of generation

Although natural gas and renewable energy differ in many aspects, similarities arise when consiering these energy sources from the perspective of an electricity-generating firm facing interrupted energy supply. Specifically, the volatile supply of natural gas – driven by exogenous weather shocks – is comparable to the intermittentcy of renewable generation caused by variations in wind speed and solar irradiation. This similarity in the source and pattern of marginal cost fluctuations allows the findings of

[12] The assumption I make is partially motivated by the fact that converting the nuclear generation facility to a new generation site of different technology is challenging, whereas converting is easy for the coal plant sites. Salem Harbor station (coal-fired) in New England would be an example.

	Proposed capacity		Approved capacity	
Fuel type	Total sum	firm-specific (largest)	Total sum	firm-specific (largest)
Renewables	1,362 MW	450 MW	850 MW	402 MW
Natural gas	5,190 MW	1,597 MW	4,003 MW	1,597 MW
Other	166 MW	42 MW	58 MW	16 MW

Notes: Table summarizes the capacities proposed and approved for construction between 2013 and 2017. *Renewables* includes Solar and Wind generation. *Other* includes diesel fuel (DFO), other waste and biomass generation (OBG), hydro (WAT) and etc. Firm-specific capacity column shows the capacity of the largest project proposed by a single firm. Capacity cleared approval is indicated by the "status" column of the dataset where I grouped U (approved and construction less than 50 %) V (approved and construction more than 50 %) and TS (construction completed and ready for operation) into those approved. Capacity is caculated using the nameplate capacity. *Source*: EIA-860.

Table C.3: Proposed Generation Capacity in New England (ISONE): by Fuel Type

this study to be more broadly applicable to transitions towards renewable energy.

How does the intermittent supply of renewable energy translate into the volatile marginal generation cost? It is important to note that the marginal cost relevant for our analysis is the marginal opportunity cost (or the expected marginal cost) that the multi-unit firms account for in their strategic dispatch decisions in the day-ahead market. The marginal cost of a renewable generator itself is close to zero when renewables are available. When renewable generators become inoperable (or expected to be inoperable in the real time) due to the weather shock, a multi-unit firm that operates these renewable assets would consider replacing them with the high-cost reserve (backup) generation, in which case the firm's marginal opportunity cost is different from and above zero. This implies that the marginal cost of a renewable generator, as perceived by the firm, is not standalone constant at zero but variable due to the intermittency.

Note that such parallelism between gas-fired generation and renewable generation draws from the assumption that renewable assets are part of a firm's strategic assets that participate in the day-ahead market (most of which are dispatchable), thus not supported under the current market system where renewables are not dispatchable and participate only in the real-time market. However, the current system and the market rules are likely to change as the market operators look for better ways of integrating the intermittent renewables. For instance, the New England electricity market operator (ISO-NE) proposed a plan to require intermittent hydro and wind powered generators with a capacity supply obligation to start offering (i.e., submit supply offer bids) in the day-ahead energy market (ISONE Newsletter, 2019).[13]. Therefore, the analogy between natural gas and renewable generations, which I demonstrated earlier, is not an overstretch.

[13]This was part of the "Do not Exceeed (DNE)" dispatch project which was effective June, 2019. *Source*: https://isonewswire.com/2019/06/04/wind-and-hydro-resources-incorporated-into-the-day-ahead-energy-market-with-second-phase-of-do-not-exceed-dispatch-project/

Firm-level capacity (approved): MW	Total	mean	min	max	p25	p50	p75	p99
Natural gas	4,003	445	1.4	1,596	3.7	200	680	1,596
Renewable	850	13	1	402	2	3.9	8.1	402
Among Renewables (approved): MW								
Wind	588	39	1.5	385	1.5	9.1	30	385
Solar	260	5	1	20	2	3	5	20

Table C.4: Firm-level Proposed (and approved) Capacity in New England: NG vs. Renewables

C.7.3 Challenges in incorporating renewable generation into the analysis

There are some practical challenges in incorporating renewable generation assets into our empirical analysis. First and foremost, incorporating renewables as the *volatile-cost* energy in the analysis is practically challenging. Note that the focus of this study is on periods when the supply of renewable energy is disrupted because the fluctuation in the marginal cost of renewable assets stems from intermittency. However, we do not yet have sufficient data (on production, marginal costs) nor an understanding of how firms would strategically utilize their renewable assets, especially in abnormal situations in which the supply of renewable energy is interrupted. This is especially so given that the non-dispatchable renewable assets were not participating in the day-ahead electricity market where strategic actions are most active. As these assets were not participating in the market, the bidding data from which we can estimate marginal opportunity costs does not exist for renewable generation assets.

Second, despite the rapid growth, the size of the existing and the planned installations of renewables is so far much smaller than that of the gas generation, especially in the Northeast where volatility is the biggest concern. For example, the total capacity of the gas-fired generation approved for installation between the years 2013- 2017 in the New England grid is almost five times larger than that of renewable generation, as shown in Table C.3 of the Appendix. According to EPA, renewable resources still play a limited role in offsetting natural gas consumption in the New England power sector, especially during the extreme weather conditions, which is the focus of this study, as wind and solar resources are not available during extreme weather conditions (EPA, 2019 Regional System Plan ISO-NE).

Moreover, renewable generation enters on a small-scale and has not been the primary energy source installed by the major strategic firms. Table C.4 provides a detailed summary of the proposed (or approved) generation capacities at the firm- and project level, by energy source. I find that, except for one project, almost all of the renewable project has a scale less than 30 MW (75th quantile), with the median scale being 4 MW, whereas that of natural gas has an average project size of 445 MW with 75th and 50th quantiles being 680 MW and 200 MW, respectively.[14] This indicates that renewable projects are

[14]When examining the capacities proposed by firms that appear in the bidding data (with significant shares), NG fired plant capacity has the mean of 340 MW, with a maximum of 1,596 MW. On the other hand, renewable generation capacity has a mean of 0.63 MW, with the maximum capacity being 4 MW. Also, the number of projects proposed by these firms is four times larger for gas-fired projects than renewables projects.

less likely to be operated by large-scale firms as part of their strategic assets. Because the main focus of this study is the strategic behavior of electricity-generating firms, the available data and institutional features at this point do not support the use of renewables as a primary replacement of coal generation.

C.8 Additional Tables

Fuel	generators (1) capacity (MW)	(2) % of total capacity
gas	10,735	31.81
gas/oil dual	6,195	18.36
oil	4,384	12.99
coal	2,314	6.86
nuclear	4,452	13.22
hydro	3,066	9.09
other	268	0.79
total	31,424	100

Notes: The table summarizes the capacity of power plants (generators) by their fuel type. Data of power plants operating in the New England grid in the winter period of 2012 is used (*Source*: SCC data, 2012, ISO-NE)

Table C.5: Summary of Generation Capacity by Fuel Type in the New England Market

		$\Delta\Delta P(\%) = \Delta P_{\text{post}} - \Delta P_{\text{pre}}$ Low Demand		⇒ High Demand	
	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P(\%)$	9.6	11.0	9.8	11.3	7.4
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
$\Delta\Delta P(\%)$	7.9	10.6	2.5	9.0	8.2
(G2) Med Gas Price					
$\Delta\Delta P(\%)$	10.1	10.2	10.4	12.4	7.5
(G3) High Gas Price					
$\Delta\Delta P(\%)$	11.3	13.0	17.6	13.7	6.6

Notes: Average values of the percentage of $\Delta\Delta P$ out of the original pre-retirement equilibrium price (P_0) are reported in the table. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: (G1) gas prices between $4 to $9/MMBtu, and (G2) between $9 and $15/MMBtu and (G3) gas prices higher than $15/MMBtu (up to $27/mmbtu). N= 348.

Table C.6: unilateral market power change, Percentage $\Delta\Delta P$ (%)

		Strategic Price			
		Low Demand		⇒	High Demand
	Total	(D1)	(D2)	(D3)	(D4)
P_{com}	98.5	75.9	87.4	88.0	124.9
P_0	105.7	80.5	93.3	94.4	134.8
P_{cour}	112.6	81.2	95.5	99.7	149.0
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
P_{com}	60.3	51.1	52.4	53.8	75.7
P_0	65.5	52.8	57.1	57.6	84.6
P_{cour}	67.0	53.5	58.4	58.4	87.2
(G2) Med Gas Price					
P_{com}	90.4	75.4	79.0	81.4	119.4
P_0	97.3	82.6	83.4	87.3	128.3
P_{cour}	100.5	83.0	84.3	88.2	137.2
(G3) High Gas Price					
P_{com}	151.1	115.0	132.4	154.1	164.5
P_0	161.0	120.2	140.7	165.3	175.8
P_{cour}	178.1	121.5	144.7	168.8	195.1

Notes: All prices reported here is of the pre-retirement (*Before*) sample. P_0 is the observed equilibrium price, P_{com} is the counterfactual competitive price, and P_{cour} is the counterfactual Cournot price. Average of simulated prices are reported in the table. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: (G1) gas prices between \$4 to \$9/MMBtu, and (G2) between \$9 and \$15/MMBtu and (G3) gas prices higher than \$15/MMBtu (up to \$27/MMBtu).

Table C.7: Price Comparisons for the pre-retirement sample: competitive vs. actual vs. Cournot

	(1) Slope (original)	(2) Slope (addfringe)	(3) Δ Slope
Demand	0.004	-0.24^{***}	-0.26^{**}
	(0.02)	(0.08)	(0.07)
Gas price	-0.04^{***}	0.17^{***}	0.25^{***}
	(0.01)	(0.04)	(0.03)

Notes: Slope (β_{th}) is the estimated slope of the residual demand curve of day t-hour h (*unit*: GWh/\$). Table reports the estimates of OLS regression of β_{th} on "Demand (GW)" and "Gas price" variables. Column (1) is the slope of the orginal (used in the baseline case) RD curve and (2) is the slope of the RD after adding new fringe suppliers of capacity equivalent to the retired generation in total. (3) is for the change in slope (Δ Slope = Slope (addfringe) - Slope (original)). Demand is the aggregate market demand of the day t- hour h market (*unit*: GWh). Gas price is the spot gas price index of day t-hour h market (*unit*:\$/MMBtu). Standard errors in the parenthesis. Hours from 5h to 23h included. N = 348.

Table C.8: Residual demand slope: original vs. CF(1)

Slope $\hat{\beta}_{th}$ (\$/ GW)	mean	min	max	s.d.
original	4.04	2.52	8.30	1.02
CF (1) - new fringe entry	10.1	3.43	28.5	4.31
Δ New - Original (\$/GW)				
level change	5.91	-3.12	22.9	4.6
% change	49.9	-67.7	88.1	28.3

Table C.9: Summary of $\hat{\beta}_{th}$: original vs. CF (1) new fringe entry

Firm name	Proposed plant	NG capacity	Description
New Entrants			
CPV company	Towantic Energy Center	805 MW	operates large-scaled projects in other states
NTE Connecticut	Killingly Energy Center	650 MW	operates large-scaled projects in other states
Loring Power Plant, llc	Loring Power Plant	80 MW	small scaled, does not operate in other market
Existing Firms			
Firm name	proposed plant	NG capacity	Description
Exelon	Medway Power Station	200 MW	adding new gas-oil dual capacity to the existing plant site
PSEG	Bridgeport station	575 MW	replacing the coal plant (383 MW) that plans to retire by 2021
NRG	Canal station	330 MW	adding new gas power plants to the existing gas generation plant
Salem Harbor	Salem Habor station	1,680 MW	converting the retired coal plant site (749 MW) to gas power plant
Wallingford Energy	Walligford station	100 MW	adding new gas plant to the existing plant site

Notes: Capacity is caculated using the nameplate capacity. For Salem Harbor, the firm (operator) has changed once in the data so I dropped the capacity proposed by the previous owner to avoid duplication.

Table C.10: Proposed Capacity in New England: Natural Gas Generation

Firm No.	Total Cap (MW)	Coal	Oil	Nuclear	Natural Gas	Other
		Generation share (%)				
1	2,381	0	32.4	51.0	13.6	3.0
2	2,264	0	0	81.3	18.7	0
3	1,201	0	0	0	49.1	50.1
4	1,146	0	82.0	0	18.0	0
5	877	54.5	33.2	0	0	12.3
6	873	52.3	2.0	0	45.7	0
7	577	0	94.5	0	5.5	0
8	569	0	0	0	0	100

Notes: Table summarizes the generation mix composition of firms categorized as 'Balanced' firms, with each firm assigned an arbitrary index (Firm No.). The 'Other' category includes generation with fuel types indicated as other biomass solid (OBS), landfill gas (LFG), municipal solid waster (MSW), wood waste solid (WDS), and hydroelectric (WAT).

Table C.11: Balanced firm characteristics

C.9 Additional Figures

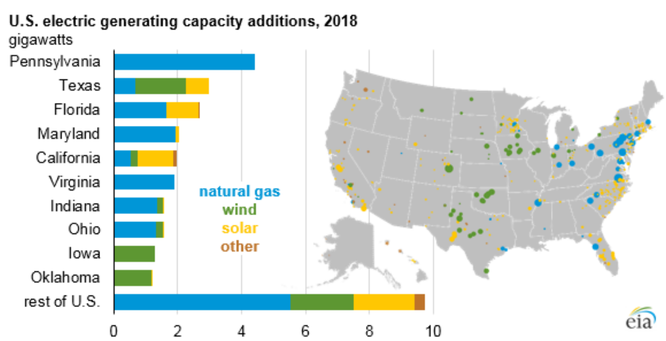
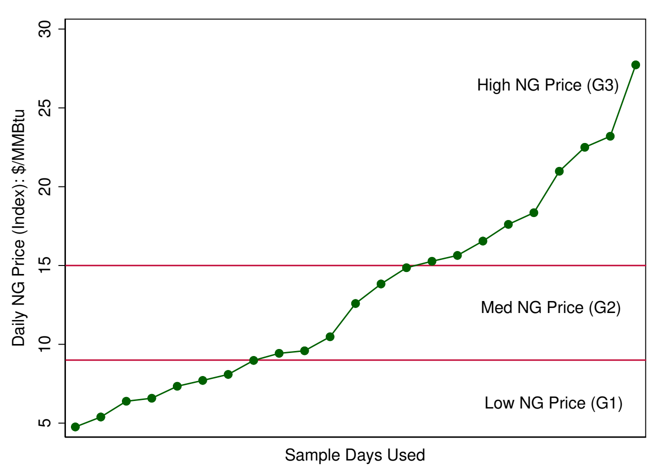
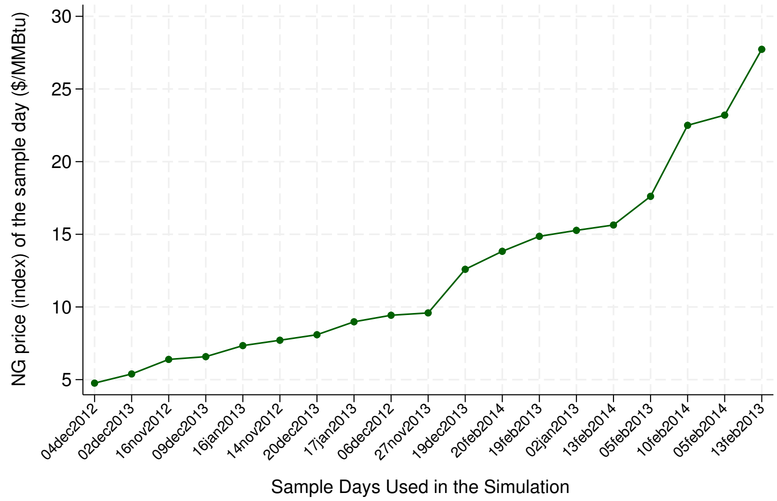


Figure C.4: U.S. Capacity Additions by Region: 2018 (source: EIA)



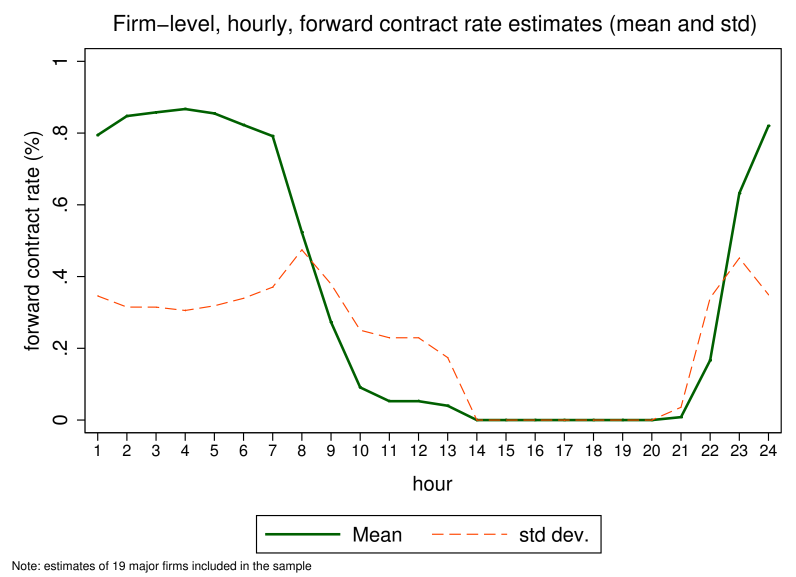
Notes: The horizontal axis shows the selected sample days aligned in an increasing order of gas price (index data) of the day, shown in the vertical axis. I divide the sample into three groups: days with NG price index below \$9/MMBtu (G1- Low), between \$9 and \$15/MMBtu (G2 - Med), and above \$15/MMBtu (G3 - High). I selected only days with NG prices above the normal level of \$4/MMBtu. Therefore, even the "Low G" category includes days with NG prices higher than this normal baseline.

Figure C.5: NG price levels of the selected sample days used in the analysis: G index categorization



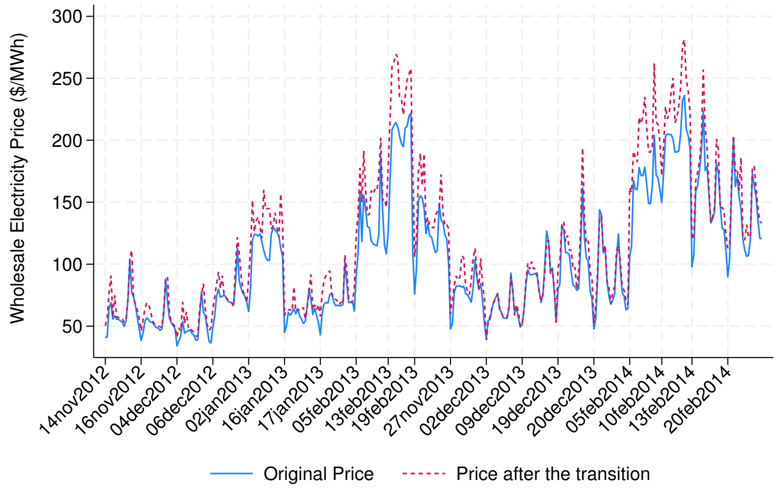
Notes: The horizontal axis displays the dates of selected sample days arranged in increasing order of the day's gas price (index data), shown in the vertical axis.

Figure C.6: Gas Price Index Values of the Selected Sample Days: With Dates



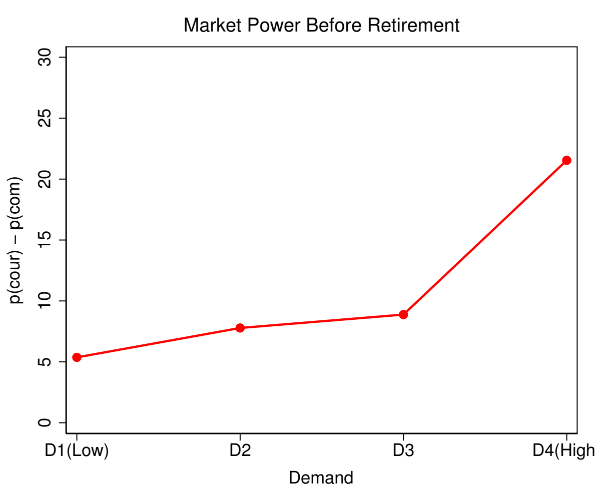
Notes: The graph above shows the cross-sectional average and standard deviation of firm-level hourly forward contract rates, γ_{ih}, estimated from the model.

Figure C.7: Forward Contract Rates: Summarized Across Firms

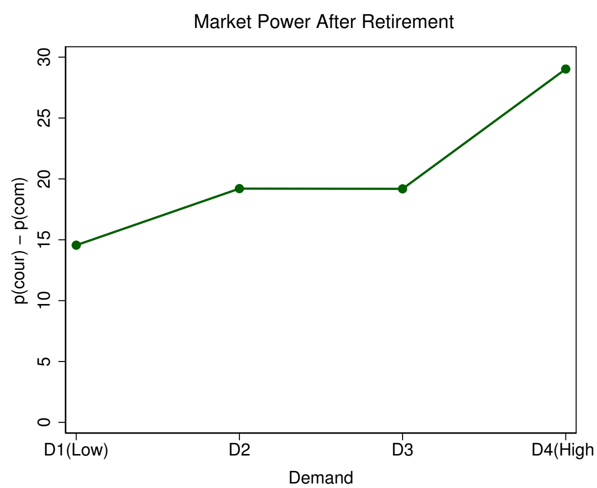


Notes: The original price comes from data and the price after the transition is the simulated Cournot price. The x-axis shows the actual date of sample days used in the counterfactual analysis.

Figure C.8: Wholesale electricity prices: before and after the transition



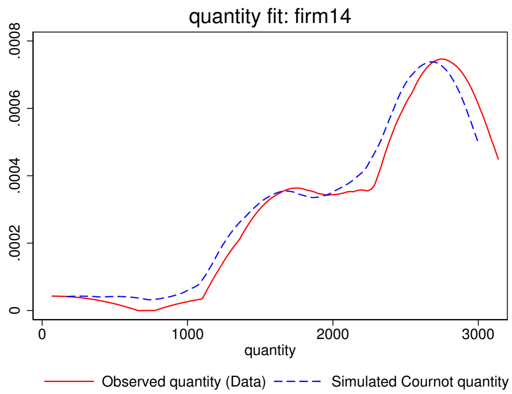
(a) Market Power Before Retirement



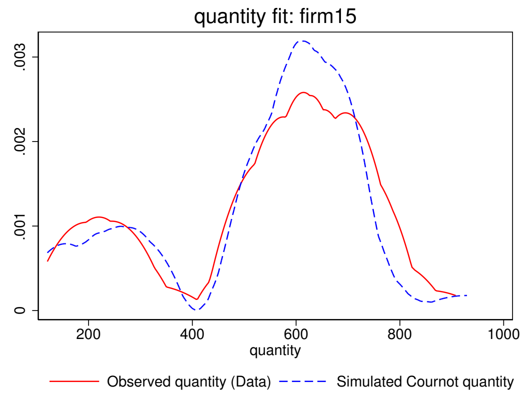
(b) Market Power After Retirement

Notes: Figure shows the markup (ΔP) averaged within each demand bin (D1 to D4) for the pre-retirement (panel (a)) and the post-retirement (panel (b)) samples.

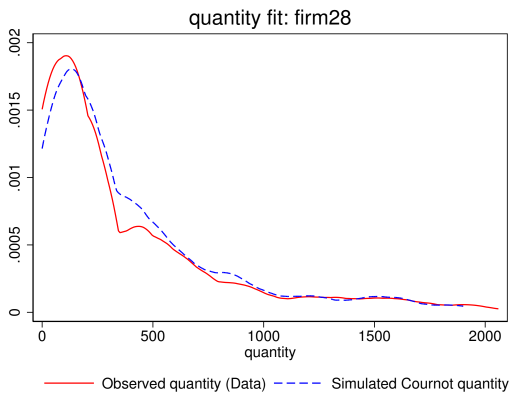
Figure C.9: Absolute level of Market Power (ΔP): before and after retirement



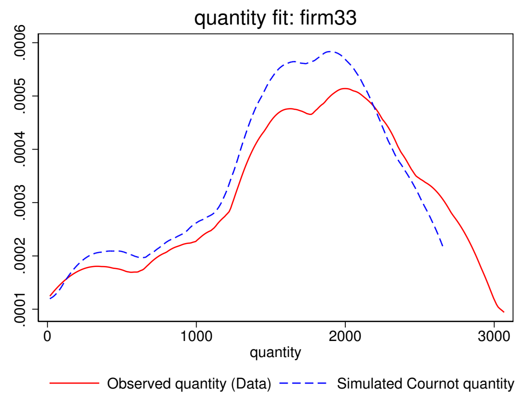
(a) firm 14



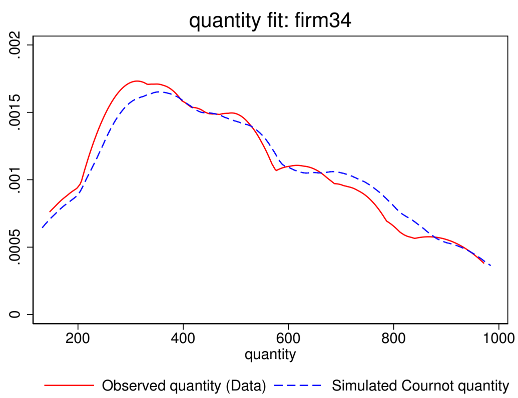
(b) firm 15



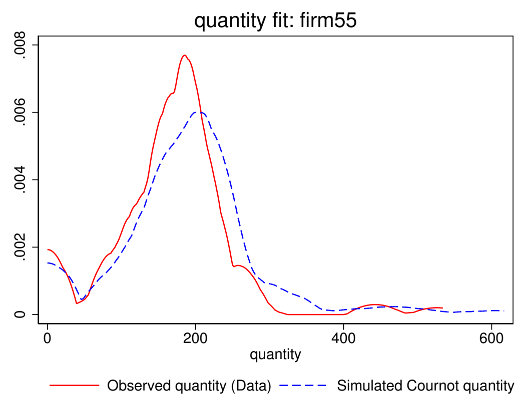
(c) firm 28



(d) firm 33

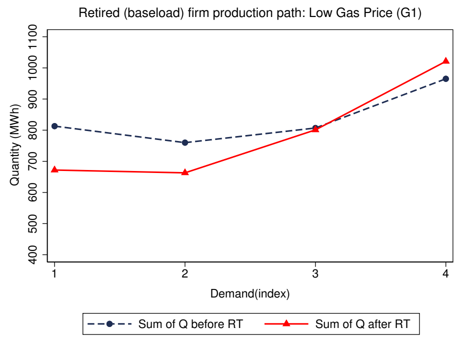


(e) firm 34

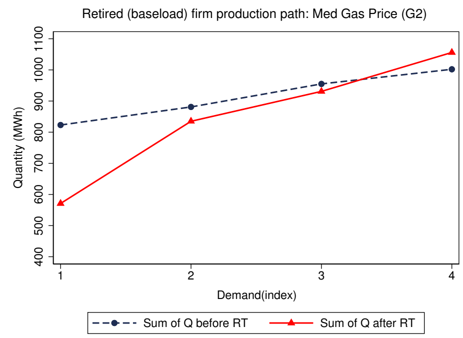


(f) firm 55

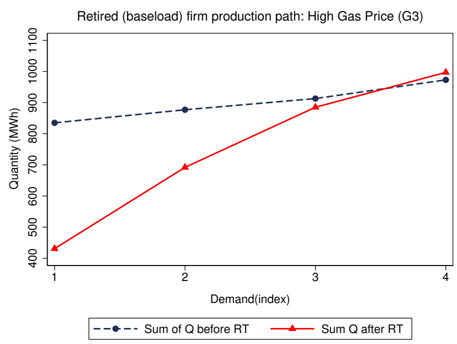
Figure C.10: Fit of the firm-specific quantities simulated using selected firm set to the actual quantity (data): pre-retirement sample



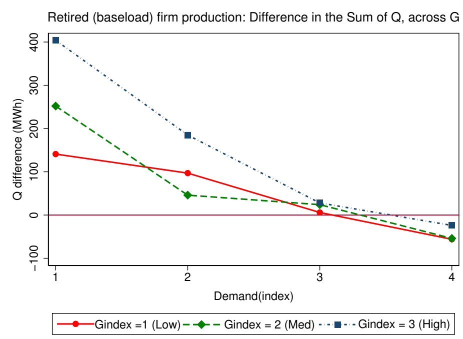
(a) Low gas price (G1)



(b) Med gas price (G2)



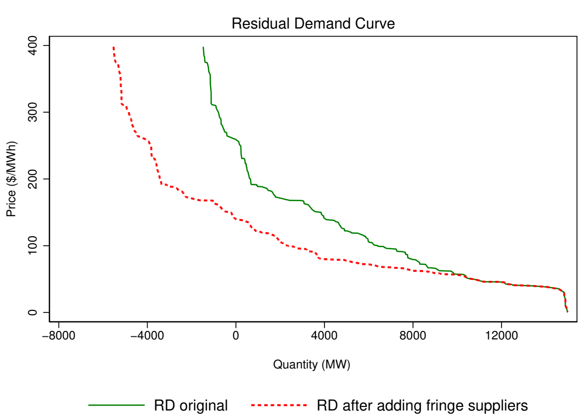
(c) High gas price (G3)



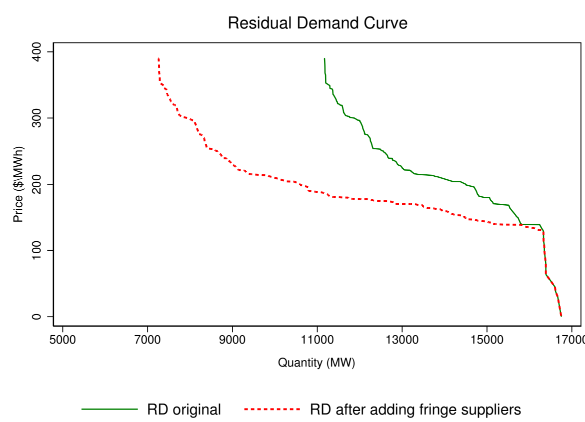
(d) Total quantity difference

Notes: Total quantity produced by "retired firms" together is plotted across demand (D1-D4), over different gas prices (G1 - G3). The dashed line shows the quantity path before the retirement and the bold line shows the quantity path after the retirement. Panel (d) summarizes the total quantity difference ($Q_{before} - Q_{after}$) across D and G, in a single plot.

Figure C.11: Retired firm's (average) production paths before vs. after the retirement

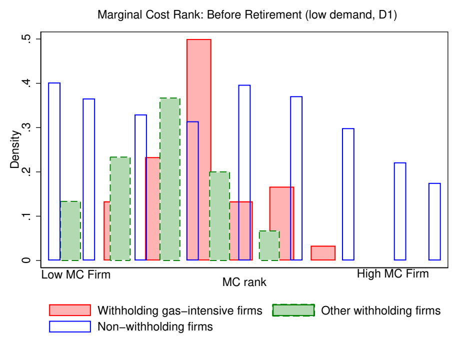


(a) t = 97: gp = $ 9.4/MMBtu

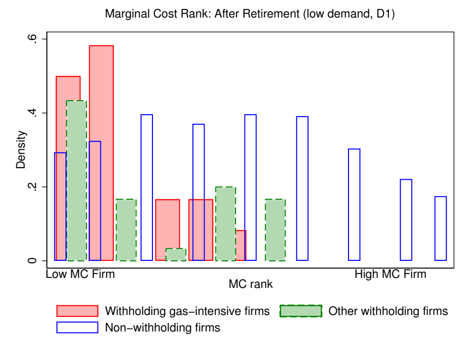


(b) t =436: gp = $ 22.5/MMBtu

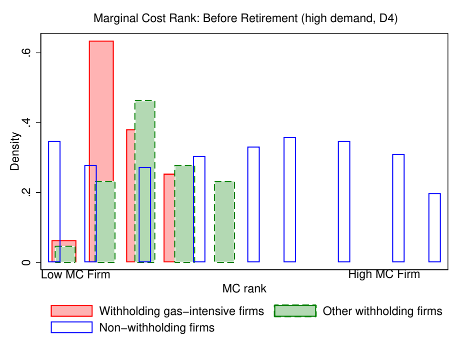
Figure C.13: Residual demand curve: original vs. after adding fringe suppliers



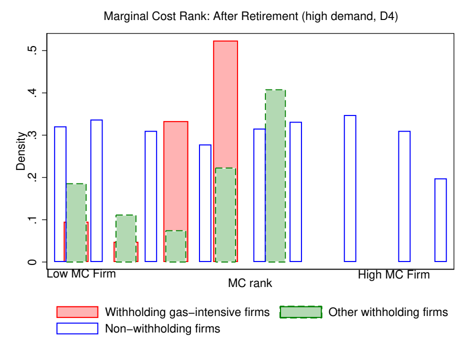
(a) Low D (D1): Before Retirement



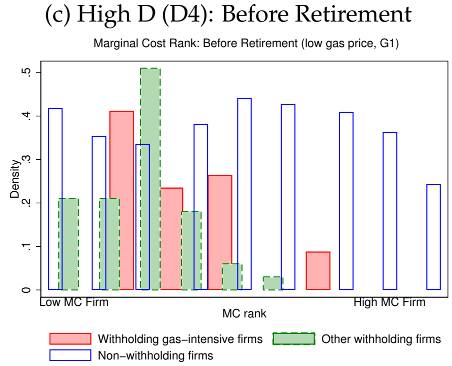
(b) Low D (D1): After Retirement



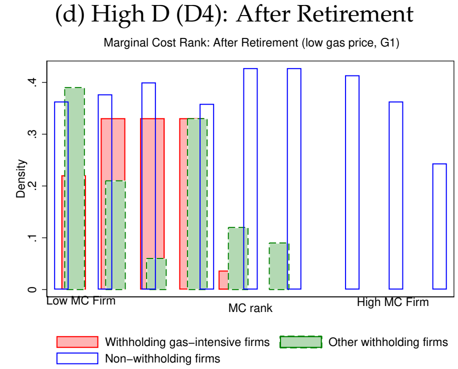
(c) High D (D4): Before Retirement



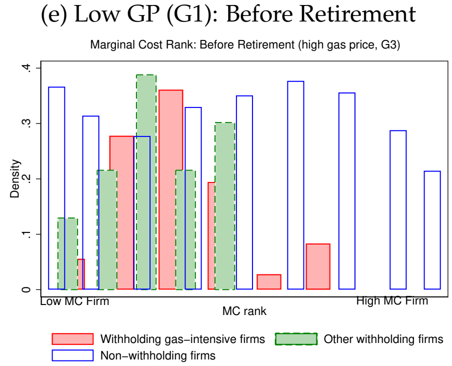
(d) High D (D4): After Retirement



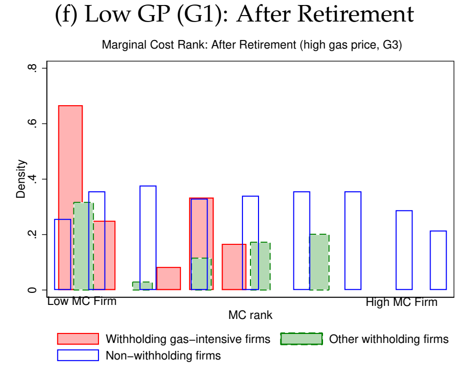
(e) Low GP (G1): Before Retirement



(f) Low GP (G1): After Retirement



(g) High GP (G3): Before Retirement



(h) High GP (G3): After Retirement

Figure C.12: MC rank: before and after the transition: by demand and gas price