Market Organization and Productive Efficiency: Evidence from the Texas Electricity Market

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Abstract

This paper examines the impact of market organization on efficiency and social welfare in the electricity market. Wholesale electricity markets exhibit two basic forms of organization: the decentralized bilateral trading market and the centralized auction market. While the centralized market may improve efficiency through information aggregation, it may also reduce efficiency by exacerbating the incentive faced by market participants to exercise market power. Taking advantage of Texas' transition from a bilateral trading market to a centralized auction market, I show that the effect of the former dominates the latter. Using detailed generation data, I find that high-cost generators were displaced by low-cost generators in production. In the nine months following the transition, the generation cost was reduced by $30.7 million, about 0.5% of the total generation cost. Although the centralized market led to private cost saving, it also had an unintended effect on emissions. For moderate estimates of marginal damage values, the increased external costs of emissions completely offset the productive efficiency gain.

Keywords: Market Design, Electricity Markets, Congestion Externality, Market Power, Emissions

JEL Classification Numbers: L51, L94, Q41, Q51

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1 Introduction

How markets are organized is an important determinant of market performance. For many commodities and financial assets, markets can be organized under two basic forms: decentralized markets where transactions are conducted through private negotiations, and centralized markets where trades are intermediated by a central coordinator. For example, stocks and bonds can be traded both over-the-counter and through centralized exchanges. It is therefore natural to ask which organizational form produces a more efficient market. Starting from Wolinsky's (1990) seminal article, a growing body of theoretical literature has devoted to the characterization of efficiency properties of the two market organizational forms (e.g., Dewatripont and Maskin (1995), Acharya and Bisin (2014), Glode and Opp (2016)). Their models highlight the critical role played by factors such as asymmetric information, search frictions and market power, but the conclusion as to which market is more efficient depends crucially on the fine details of the models.

Stepping away from the theoretical contention, this paper provides empirical evidence on the relationship between market organization and efficiency in an industry where the choice between decentralized and centralized markets has received considerable attention. Over the past 20 years, the electric sector in the U.S. has undergone a drastic reform. 17 states plus District of Columbia have restructured their markets, unbundling electric generation and retail service from transmission and distribution. For these restructured states, the organization of the wholesale electricity markets can be broadly categorized into two forms: the decentralized bilateral trading market and the centralized auction market. The two approaches envision different roles for the system operator in managing the markets. While the bilateral market relies mostly on individual firms to make private transactions and decentralized dispatch decisions, the centralized market, in contrast, relies mostly on the system operator for scheduling and dispatch using bids submitted by generators. Among policy makers and academics, significant debate has been provoked by the question of which market design supports a more efficient and competitive wholesale power market (Hogan, 1995).

This paper addresses this question by taking advantage of a market redesign in the Texas electricity market. On Dec 1st 2010, Texas switched from a bilateral trading market to a centralized market. The efficiency impact of the market transition is, in theory, ambiguous, since both imperfect information and market power play a critical role in determining the outcome in this market. On one hand, the centralized market improves market efficiency through information aggregation[1]. An important feature of the electricity market is the p-resence of congestion externality, i.e. in a congested network how much generation quantity from a particular source can be accommodated by the network depends on the generation quantity of all other sources. Under the bilateral trading market, it is difficult for market participants to resolve this externality in a Coasian fashion, due to limited information processed by each participant about others' schedules and the difficulty to aggregate this information in a bilateral way. By contrast, under the centralized market, the system operator can utilize its central position to aggregate information from all generating units and dispatch resources simultaneously to resolve the externality problem. On the other hand, the centralized market may result in efficiency loss if the bids submitted by market participants are far in excess of their marginal costs. Evidence of high price-cost margins has been previously found in the California market by Joskow and Kahn (2002) and Borenstein et al (2002)[2]. Consequently, whether the centralized market yields a more efficient outcome remains an open question. In Section 3, I develop a relatively simple yet compelling example that illustrates the role of imperfect information and market power in affecting the generation allocation under different market schemes.

The core of this paper exploits detailed data on hourly unit-level generation to empirically examine the effect of the market redesign on efficiency. In the relatively short period preceding and following the redesign, there are few changes in the generation capacity, cost, technology and transmission capacity. This provides an opportunity to estimate the effect of market organization without contamination from differences in other aspects of the market. To create a credible counterfactual of what would be the generation outcomes had the market not switched to the centralized dispatch, I rely on an econometric approach relating unit-level generation to demand while also controlling for fuel prices and time fixed effects. This approach offers considerable flexility and avoids modeling the complex grid and firms' behavior in detail. Using high-frequency, micro-level data collected from several sources, I estimate this relationship semi-parametrically and separately before and after the redesign and then use the estimates from before to form the counterfactual for after. With the counterfactual generation, I can then estimate the changes in total generation costs. I discuss the details of my data and the empirical strategies in Section 4 and 5.

[1] In studying financial markets, Acharya and Bisin (2014) proposes a model in which a lack of transparency of trade positions leads to counterparty risk externality. They also conclude that the centralized market improves efficiency by aggregating information on these trades.

[2] A growing body of research has also examined the role of transmission constraints and shown that congestion adds an additional layer to the complexity of the market and opens up more opportunities for gaming. See Cardell et al (1997), Borenstein et al (2000), Joskow and Tirole (2000), Wolak (2015) and Ryan (2014).

The primary finding of the paper is that the centralized market improves productive efficiency. The market redesign led to significant changes in generation patterns. As the relatively cheaper resources, coal generation on average increased by 511 MWH per hour, a 3% raise in the utilization of the overall coal capacity. For natural gas generators, the reduction came from combined-cycle plants and steam turbines, while combustion turbines experienced some increase in generation given its fast-ramping capabilities. The impacts are heterogeneous for different generators at different demand levels. While the increase in coal generation occurred at all demand levels, the changes for the most expensive gas generators, i.e. combustion turbines and steam turbines, only started to show up during high demand hours. For combined-cycle natural gas generators whose costs are in between, they experienced a decrease when demand was low, which is consistent with the substitution to coal, but the change went away during high demand hours when they became inframarginal. Overall, the change in the generation pattern indicates the displacement of high-cost generators by low-cost generators in production. Accordingly, the average hourly generation cost is estimated to be $5,062 lower than what would have been for the nine months post redesign. This amounts to annual cost savings of $44.3 million, a 0.5% decrease of the total generation cost. The improvement in productive efficiency of the market suggests that the benefit of information aggregation outweighs the concern for market power under the centralized market.

Although the centralized market led to private cost saving, it also had an unintended effect on social welfare through impacts on emissions. A second finding of the paper is that the environmental consequence of the market redesign is non-negligible. The increased generation from coal also led to significantly more carbon dioxide emissions. On average, carbon dioxide emissions increased by 351 tons per hour, which is a 1.3% increase in total carbon dioxide emissions. Applying different estimates of the social cost of carbon from EPA (2010), I find that the external cost from carbon dioxide emissions completely wiped off the private efficiency gain for just moderate estimates of the social cost. The market redesign also introduced changes in SO_2 and NO_x emissions. Overall, the market redesign is welfare-reducing if the external costs of emissions are taken into account. Section 6 and 7 present the findings and discuss their implications.

This paper builds on and contributes to the market design literature, especially in the context of the electricity industry. Wilson (2002) provides an overview of the architecture of the electricity market and summarizes the relative merits of different organizations. Empirical evidence, however, is sparse with notable exceptions of Mansur and White (2012) and Cicala (2015). Both studies estimate the gains from trade after market expansion. This paper differs from their work in important ways. Firstly, I focus on a new setting where the market transition does not involve any change in the boundary of the market. This helps ruling out the possibility that trading is impeded by administrative barriers across markets other than imperfect information regarding congestion externality. Secondly, the econometric approach I employ allows for considerable flexibility and does not make any explicit assumption on firm behavior or the grid. This is in contrast with Mansur and White (2012) which assumes away the impact of market power. Thirdly, I am the first to examine the environmental consequences of the electricity market design, which is an important piece that has been overlooked by previous studies. Finally, I provide detailed evidence on the heterogeneous effects across generators and demand levels.

2 Background

This section presents relevant background information about the electricity market. I start by providing a brief overview of the features of electricity which necessitate the adoption of independent system operators in the wholesale electricity market. Next, I discuss the market design of the wholesale electricity market and describe the role of independent system operators under different market organizational forms. Finally, I introduce the event the empirical analysis focuses on – a redesign of the Texas electricity market.

2.1 Basics of the Electricity Market

Compared to other commodities, electricity is an unusual good in several ways. First, the demand for electricity varies widely from hour to hour and day to day, but is almost perfectly inelastic in the short-run. Very few consumers of electricity are willing or able to adjust consumption in response to price fluctuations. Second, electricity cannot be stored in meaningful quantities. Therefore, the aggregate generation of electricity and the consumption of electricity must be balanced at every second. Sufficient imbalances cause brownouts (dropping electrical frequency) or blackouts (complete loss of electrical service). Third, electric power networks are not like railroad networks where a supplier makes a physical delivery of a product through a designated path to a specific customer at another point. Electrons flow through the transmission network according to physical laws (Kirchhoff's Laws), not the laws of financial contracting. Finally, to ensure the reliability of the grid, the entire transmission network must meet certain physical constraints, such as frequency, voltage and capacity.

Because of these attributes, the proper functioning of the electricity market calls for coordination among market participants. The entire electricity market in the U.S. is segmented into many power control areas[3]. Within each power control area, a balancing authority is the coordinator responsible for ensuring the load-generation balance and the reliability of the grid. Traditionally, vertically integrated utilities are the balancing authorities for their exclusive service territories. These firms own all generation assets and transmission lines within their territories. So they can use internal scheduling and dispatch to deliver power at the minimum cost. While power exchanges take place among utilities, the transactions are usually based upon mutual agreement with each utility maintaining control over use of its own transmission facilities.

The restructuring wave starting in the late 1990s broke up the monopoly system of electric utilities and opened up the wholesale electricity market for competition. Investor-owned utilities were required to functionally unbundle wholesale generation from transmission services. To promote wholesale market competition and ensure open and non-discriminatory access to transmission services, FERC order 888 suggested adopting an Independent System Operator (ISO) as the balancing authority for these restructured markets. Several ISOs emerged as a result, including California ISO, PJM Interconnection, New York ISO and New England ISO. These ISOs do not own any transmission assets, but assume a functional control of the grid. Currently, there are 9 ISOs operating in North America as shown in Figure 1[4].

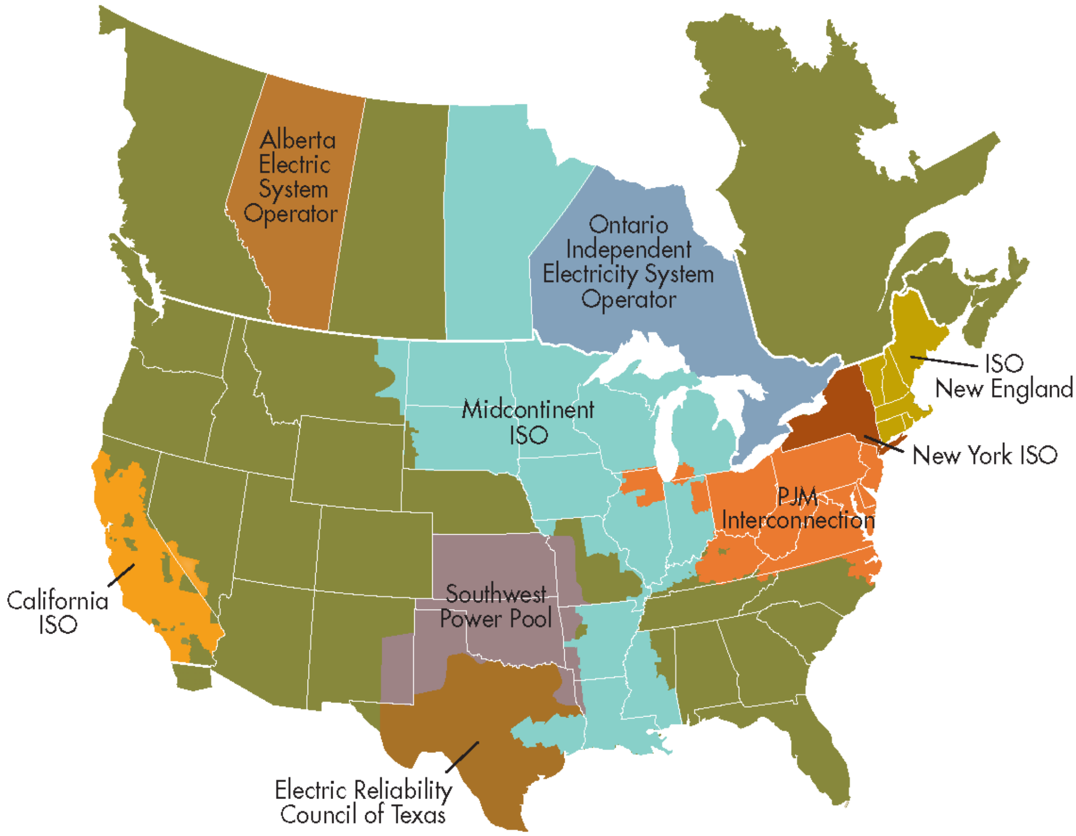
2.2 Market Design of the Wholesale Electricity Market

How ISOs organize the wholesale electricity market varies across regions. However, the various market structures can be broadly categorized into two paradigms based on the scope of the system operator's authority and the extent of centralization.

The first paradigm is referred to as the bilateral trading market or Min-ISO. Under the bilateral trading scheme, the role of the system operator is conceived of as being limited and

[3]A power control area (PCA) is a portion of an integrated power grid for which a single dispatcher has operational control of all electric generators. PCAs range in size from small municipal utilities such as the City of Columbia, MO, to large power pools such as PJM Interconnection. Generation and transmission facilities are physically interconnected throughout the grid, but controlled by each PCA. Since the operations of these facilities have impacts on facilities in remote control areas, the U.S. industry has developed a complex set of standard operating protocols through the National Electric Reliability Council (NERC) and its eight regional reliability councils.

[4]Here, I consider ISO and RTO (Regional Transmission Organization) as synonyms.



Source: ISO/RTO Council

Figure 1: ISOs operating in North America

relatively passive (Joskow, 2000). In such markets, buyers and sellers of electricity engage in private negotiation and enter into bilateral contracts. The resulting bilaterally arranged schedules are reported to the system operator. The system operator evaluates the reliability of the grid and operates the energy market needed to mitigate the energy imbalances in real time. This model assumes that bilateral trading will do most of the resource allocation work, with the system operator only playing a residual balancing role. This model has been adopted by MISO (2001-2005), ERCOT (2002-2010), CAISO (2001-2009) and NETA in the U.K. (2001-current).

The other paradigm is the centralized auction market, usually called the "electricity pool" or Max-ISO. This framework envisions the system operator playing a much more active role in both the energy market and the management of network congestion. Generation resources submit bids for supplying energy to the market. The system operator takes the portfolio of supply offers and uses an optimization algorithm to find the lowest bid-based cost allocations, and associated clearing prices which balance supply and demand at every node on the network subject to operating constraints. This model has been adopted by Northeastern ISOs (NYISO, ISO-NE, PJM), MISO (2005-current), ERCOT (2010-current) and CAISO (2009-current).

2.3 The ERCOT Redesign

The Electric Reliability Council of Texas (ERCOT) is the nonprofit corporation that has been certified by the Public Utility Commission of Texas (PUCT) as the independent system operator for the ERCOT Region[5]. ERCOT serves 85 percent of Texas' load, 75 percent of Texas' land, and approximately 23 million customers. ERCOT is unique in that it is an ISO, a NERC region and one of the three interconnections in North America. There are limited power exchanges between ERCOT and neighboring regions, making it an isolated "electricity island" that is ideal for this study[6].

ERCOT started as a bilateral trading market and transitioned to a centralized auction market on December 1st 2010[7]. In Appendix A.1, I provide more details on the scheduling and dispatch procedures under both market designs. The market redesign creates a natural experiment which I exploit to examine the effect of the organizational forms on market outcomes.

[5]ERCOT was initially formed to comply with NERC requirements in 1970. In 1995, the Texas Legislature amended the Public Utility Regulatory Act to deregulate the wholesale generation market, and later in 1999 passed Senate Bill 7 (SB7) to deregulate retail electric market. Afterwards, PUCT began the process of expanding ERCOT's responsibilities to enable wholesale and retail competition and facilitate efficient use of the power grid by all market participants. On July 31, 2001, ERCOT began to operate as a single balancing authority for the entire ERCOT market, fulfilling the requirements of an ISO as specified in FERC Order 888.

[6]ERCOT is not synchronously connected to the Eastern and Western Interconnections. Power can be exchanged only via DC-ties between ERCOT and surrounding regions. There are two commercially operational DC-Ties between ERCOT and the Eastern Interconnection: North (DC_N) located near Oklaunion and East (DC_E) located near Monticello. They are capable of transferring a maximum power of 220 and 600 megawatts respectively. There are three additional DC-Ties connecting ERCOT and Mexico. There are no DC-Ties between ERCOT and the Western Interconnection. The overall net interchange accounts for only 0.65 percent of total net generation as of 2010.

[7]The redesign of the market was directed by PUCT in September 2003 with the goal of improving market and operating efficiencies. The initial implementation date was Oct 1st 2006. However, due to cost overruns and software problems, the market transition was postponed several times. The new market was finally launched on December 1st 2010.

3 Congestion Externality, Information Aggregation and Market Power

At first glance, it may not be obvious which market scheme will produce a more efficient outcome. This section demonstrates that the result is indeed ambiguous in theory and hence needs an empirical examination. With a simple example, I first illustrate the concept of congestion externality, a special form of externality in the electricity market. Then I explain why the centralized market is superior at resolving this externality problem and potentially improves market efficiency. Finally, I show that the centralized market may also reduce efficiency if market power is taken into account.

3.1 The Congestion Externality Problem

As mentioned in Section 2, electricity is transmitted through an interconnected network subject to transmission constraints. Network congestion creates a special type of externality problem for the electricity market –the "congestion externality" problem. Congestion externality means that how much electricity from a particular source can be accommodated by a congested network depends on how much electricity is generated by other sources. There is efficiency gain if market participants can internalize the externality by pairing up transactions.

The congestion externality problem can be illustrated with a simple example. Let's consider an equilateral triangular network with three generators. These three generators are located at the vertices, A, B and C, with different marginal costs, as shown in Figure 2.a. All three transmission lines are identical, except that the line between A and B has a capacity limit of 100 megawatts. At point C, there is also a demand of 300 megawatts.

To meet this demand, the most efficient allocation is to let the least costly generators produce 300 megawatts. Therefore, we should procure 300 megawatts from generator A. The actual flow is guided by the Kirchhoff's Law which states that when there are multiple paths connecting the same orientation and destination, electrons will flow the least resistant route[8]. There are two routes connecting A and C, and one of them is twice as long as the other one. Therefore, the resistance of the indirect path is twice as high as the resistance of

[8] The exact statement of Kirchhoff's (voltage) law is that the directed sum of the voltage around any closed network is zero. By Ohm's law, voltage equals current times resistance of the electrical circuit. Let the currents going through line $\overline{\mathrm{AB}}$, $\overline{\mathrm{BC}}$ and $\overline{\mathrm{AC}}$ be $\mathrm{I_{AB}}$, $\mathrm{I_{BC}}$ and $\mathrm{I_{AC}}$ respectively. Then the combination of the Kirchhoff's law and Ohm's law dictates the following relationship: $\mathrm{I_{AB}}+\mathrm{I_{BC}}-\mathrm{I_{AC}}=0$. Under scenario (a), $\mathrm{I_{AB}}=\mathrm{I_{BC}}=\frac{1}{2}\mathrm{I_{AC}}$.

the direct path. Electrons will be split in 1:2 ratio between the indirect path and the direct path. Figure 2.a shows the resulting electrical flows.

Now imagine we have a higher demand of 600 megawatts at point C. Note that at this point, the transmission line between A and B reaches its capacity limit. Because we cannot direct the flow of electrons, some electrons will go through the route between A and B, if there is an increase in production from generator A. Excess flow over the capacity limit will damage the transmission line and cause reliability issues. Therefore, we cannot increase the production from generator A to fulfill the increasing demand[9]. The natural tendency is to look for the second least costly generator, in this case, generator C. As a result, 300 megawatts are produced by generator A and 300 megawatts are produced by generator C. The total generation cost is $3900. The triangle in Figure 2.b illustrates this situation, which I refer to as the "naive allocation".

The naive allocation is inefficient because it overlooks the complementarity among generation sources in the network. Suppose we have generator B provide 150 megawatts. This seems to be an inefficient arrangement because B is the most expensive generator. But the production by generator B alters the resistance of the indirect path from A to C, and thus enables greater flow from generator A through the direct path between A and C without adding more flow through the congested path between A and B[10]. The triangle in Figure 2.c illustrates the resulting allocation. The total generation cost is $3600, which is lower than the generation cost under the naive allocation.

3.2 Imperfect Information and Information Aggregation

This example shows that in order to reach the lowest possible production cost to serve the demand, a firm must know 3 pieces of information: the marginal costs of the generators, the structure of the network, as well as the scheduled flows by all other firms in every section of the transmission network.

[9]It is natural to ask why not close down the link between A and B so that all of the cheap power can flow directly to consumers at C. Transmission lines like this are typically built for reliability reasons. For example, in case one of paths fails, the other provides an alternative to deliver supplies. Although transmission lines can be disconnected from the grid through a "disconnector" or a "circuit breaker", they are usually not intended for normal control of the circuit, but only for protection and safety isolation during service or maintenance.

[10]Recall that in footnote 8, we have $I_{AB}+I_{BC}-I_{AC}=0$. This means that we can have a higher I_{AC} by increasing I_{BC} with the same I_{AB}.

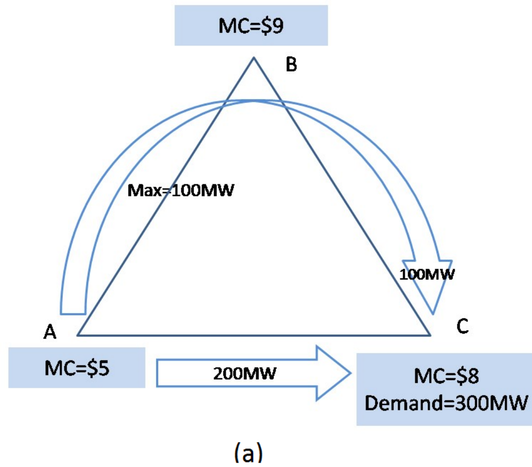
Under the bilateral trading market, the imperfect information possessed by each market participant may prevent them from identifying the congestion externality and reaching efficient allocations. Market participants may have a good idea of generators' marginal costs, given the similarity of the technology and the abundance of public data. However, they have little information on others' scheduled transactions since transactions are negotiated privately and schedules are made independently. Moreover, the complexity of the actual grid adds to the difficulty of identifying the externality. Although it seems that they can figure it out gradually through repeated interactions and learning by doing, it is an illusion created by the simplicity of the network in the example. The actual transmission network has hundreds of lines with thousands of nodes. Modeling a grid like this requires substantial effort and considerable computing power which can easily cost hundreds of millions of dollars. Therefore, it is prohibitively costly for market participants to collect scheduling information from every other generator and optimize over every segment of the grid on their own. As a result, the externality cannot be resolved in a Coasian fashion under the bilateral trading market.

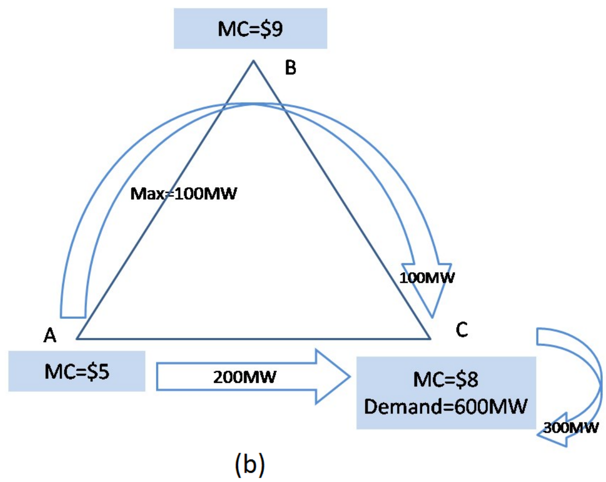
By contrast, under the centralized market, the optimization algorithm used by the ISO directly takes into account the physical constraints of the actual transmission network and minimizes generation cost over the entire system simultaneously given information reported by generators. Given ISO's advantageous position at aggregating market information and dispatching resources, the centralized market is superior at resolving the externality problem. This view on the source of efficiency gain is also shared by Mansur and White (2012).

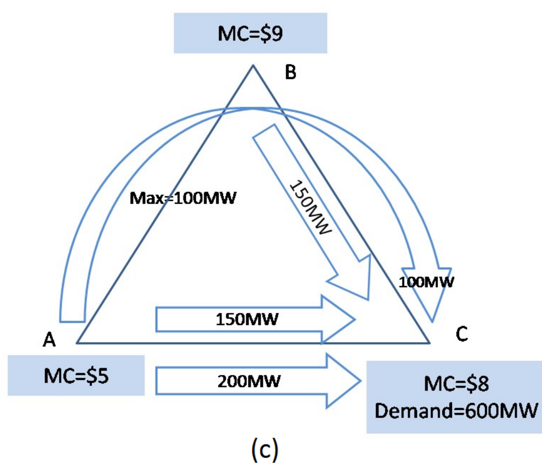
3.3 Market Power

An implicit assumption behind the analysis in the previous section is that marginal costs are observed and used to find economic dispatch. In fact, optimization is based on the bids submitted by suppliers. Inefficiency results when firms deliberately withhold their generation capacity or bid prices substantially in excess of their marginal costs such that their order on the supply curve is affected[11]. Evidence of such manipulation has been found in both the U.K. market and the California market (Wolak and Patrick (2001), Joskow and Kahn (2002)), which eventually led to the abandonment of the electricity pool.

[11]Note that the exploitation of market power does not necessarily indicate efficiency loss. If all firms simply bid twice their marginal costs, this will not change their order in the supply curve and hence incur no efficiency loss, despite of the oligopoly rents they will enjoy. Under this scenario, the exercise of market power only causes transfers of surpluses from consumers to suppliers.

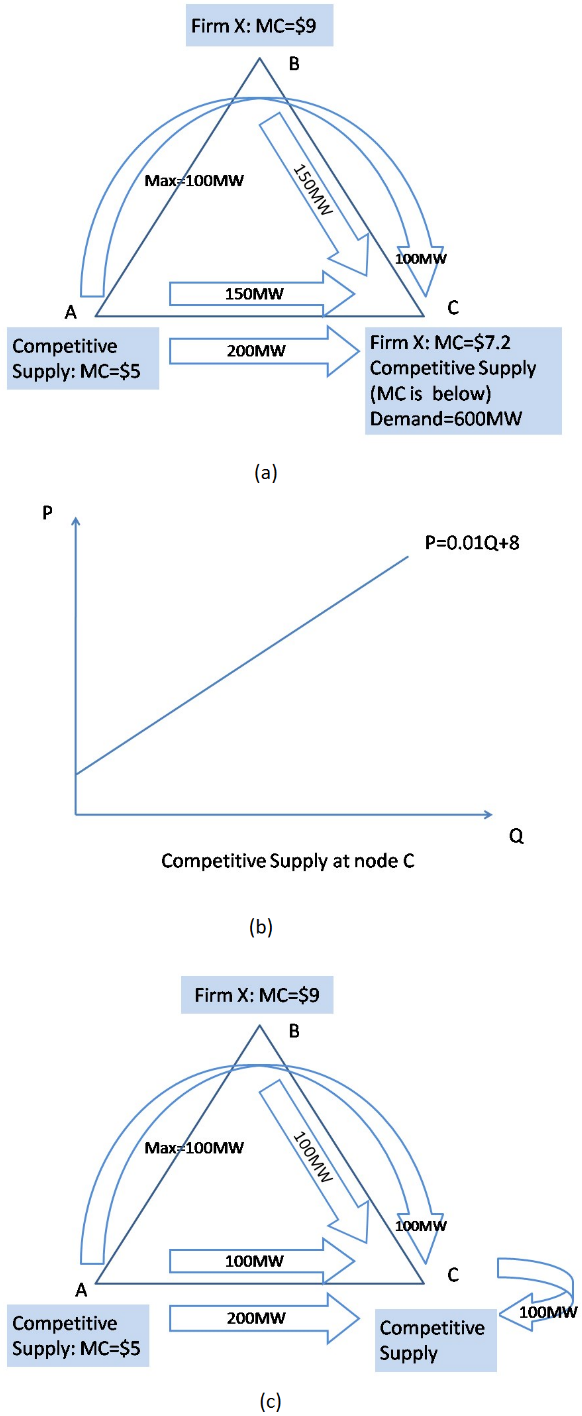






Notes: These figures provide an example illustrating the notion of congestion externality. Figure (a) shows the optimal allocation when demand is 300 megawatts. Figure (b) and (c) show the "naive allocation" and the optimal allocation when demand is 600 megawatts. See the text for details.

Figure 2: An Example Illustrating Congestion Externality



Notes: These figures provide an example illustrating the effect of market power. Figure (a) shows the market structure. Firm X has two plants located at node B and C. Competitive suppliers are located at node A and C. The supply curve of the competitive fringe at node C is given in Figure (b). The power flows drawn in Figure (a) indicate the efficient allocation when Firm X acts competitively and marginal costs are used to minimize the generation cost. Figure (c) presents the outcome when Firm X exercises its unilateral market power. See the text for details.

Figure 3: An Example Illustrating Market Power

To see how the exercise of market power reduces efficiency, let's consider a similar example as in Figure 2 but with some additional details on market structure. Figure 3.a summarizes the situation. There is a mass of competitive suppliers located at node A with a constant marginal cost of \$5. A competitive fringe supplier sits at node C with the marginal cost curve indicated in Figure 3.b. In addition, Firm X owns two generating units, one at node B and another at node C, with marginal costs of \$9 and \$7.2 respectively. The competitive suppliers take the strategies of the Firm X as given and act as price takers.

It is easy to verify that under this setup, the most efficient allocation remains unchanged: we should procure 450 MW from suppliers at A and 150 MW from Firm X at B. This is the outcome the system operator will reach when marginal costs are submitted as bids, or equivalently firm X is acting competitively. The equilibrium price at point B is \$9 and the profit of Firm X is \$0.

Now let's think about how Firm X can take advantage of its unique position in the congested network to increase its profit. One megawatt withheld at B means that two additional megawatts have to be generated at C, which drives up the prices at both B and C. Firm X has to make a classic tradeoff between profiting from higher quantity versus higher price. Assume Firm X uses the quantities it supplies as the leverage. At optimum, Firm X should supply 100 MW at point B, and 0 MW at point C, while the competitive fringe makes up for the remaining demand[12]. Figure 3.c shows the allocation. The equilibrium prices at point B and C are \$ 13 and \$9 respectively[13]. Firm X's profit is \$400. Relative to the competitive benchmark, firm X is able to increase its profit by restricting its output. The resulting allocation is no longer efficient. The total generation cost becomes \$3750, which is not only higher than the efficient allocation, but also higher than the generation cost under the naive allocation[14].

This example demonstrates that the exercise of market power may significantly affect the generation outcome. Therefore, the effect of the market redesign is the combination of impacts from changes in the management of congestion externality and changes in the

[12] See Appendix A.2 for details.

[13] The outcome will be the same if I assume Firm X competes by bidding into the pool. The optimal strategy then is to bid \$13 and \$9 for units at B and C.

[14] Recall that the naive allocation is the allocation when marginal costs are known but complementarity among generation sources is not taken into account. In this case, the naive allocation will be procuring 300 MW from A and 300 MW from Firm X at point C. The resulting generation cost for the naive allocation is \$3660.

exercise of market power[15]. To the extent that bids may deviate from marginal costs, the perceived improvement from centralized dispatch may not be realized. Therefore, whether the centralized market will improve market efficiency is an empirical question.

4 Data

For this study, I compiled a detailed and comprehensive dataset from a variety of sources. Most of the data are publicly-available. The sample period runs from Jun 1st 2010 to Aug 31st 2011, covering 6 months before the redesign and 9 months after the redesign[16].

4.1 Generation Data

The primary data I use for generation are provided by ERCOT. For each generating unit under ERCOT's control, I observe the net electrical output every 15 minutes[17]. I aggregate the net generation up to the hourly level to be consistent with the other data. I am missing a few days right after the redesign, due to data anomalies and defects ERCOT encountered. Despite that, the ERCOT data are comprehensive and accurate. Overall, there are 429 units, at 218 plants, which supply electricity to the grid managed by ERCOT[18].

I supplement ERCOT's generation data with EIA's Annual Electric Generator Report(EIA-860 form) and Power Plant Operation Report (EIA-923 form) to determine ERCOT's generation portfolio. Table 1 describes the share of ERCOT's annual generation quantity and capacity by fuel type. Electricity generation in ERCOT mostly comes from coal, natural

[15]It would be interesting to directly compare market power under the two market designs. Although lots of data exist for bids submitted in the centralized auction market, price data on bilateral contracts are rarely available due to the confidential nature of the bilateral transactions. As a result, existing literature remains silent on the market power issue in the bilateral trading.

[16]I exclude dates between Feb 2nd 2011 to Feb 5th 2011. During this period, a strong arctic front approached Texas and resulted in the lowest temperature in 20 years. The extreme weather conditions drove up the demand for electricity. According to EIA's 2009 Residential Energy Consumption Survey, about half of Texas residents use electricity for heating. At the same time, the coldness also affected generation performance. More than 8,000 MW of generation unexpectedly dropped off line (40% are coal generators). The combination of these factors led to rotating outages on the ERCOT grid.

[17]A generating unit is a single turbine along with a boiler and a smoke stack. A power plant usually consists of several, independently operating generating units. For combined cycle natural gas generators, however, the output decision is jointly made for both the combustion turbine and the steam turbine. Therefore I treat them as one single unit.

[18]Not all the generating units in the ERCOT territory are subject to ERCOT dispatch. There are firms which provide electricity only on private networks. Nor are all the generating units dispatched by ERCOT located in Texas. In particular, the Kiamichi Energy Facility is located in Oklahoma.

For subsequent analysis, I also drop generators whose cumulative generation is less than 15 megawatt hours during the sample period. These units are not economically important.

gas, nuclear and wind, while the rest only makes up about 1% of the total generation.

Fuel Type	Share of Capacity(%)		Share of Generation(%)	
	2010	2011	2010	2011
Coal	19.95	20.34	35.15	35.61
Hydroelectric	0.58	0.55	0.28	0.15
Natural Gas	64.36	63.55	44.59	44.60
Combined Cycle	37.99	39.17	38.00	37.97
Combustion Turbine	7.13	7.06	3.52	3.72
Steam Turbine	19.24	17.32	3.07	2.91
Nuclear	5.17	5.27	12.08	10.96
Wind	9.45	9.79	6.90	7.71
Others[19]	0.49	0.50	1.00	0.97

Notes: This table reports the share of capacity and the share of generation quantity for different resource types in 2010 and 2011. Data come from EIA-860 forms and EIA-923 forms.

Table 1: Generation Composition in ERCOT: 2010-2011

4.2 Generator Characteristics

I obtain plant- and generator-level characteristics from EIA-860 forms, EPA's Continuous Emissions Monitoring System (CEMS) and eGrid[20]. For each generating unit, I observe its ownership, nameplate capacity, fuel type, technology, sector, commercial operating date, operating status and location among other information. For generators covered in CEMS, I also observe their hourly CO_2, SO_2 and NO_x emission quantities and heat inputs.

For thermal generators, I use these data to measure the average CO_2, SO_2 and NO_x emission rates and heat rates. Emission rates are calculated by dividing total emission quantities (in short tons or pounds) by total net generation (in MWhs). Heat rate is the ratio of thermal energy input against electricity output. For generators covered in CEMS, I estimate the average heat rate for each unit by using the slope of regressions of heat inputs (in MMBtus) on net generation (in MWhs). For generators not covered in CEMS, I use EPA's eGrid data to obtain plant-level nominal heat rates. Heat rate reflects power plant's efficiency: the lower

[19] Others include biomass, petroleum coke, distillate fuel oil, solar and electricity storage.

[20] All fossil-fuel generating units with at least 25 megawatts of generating capacity have to report their hourly gross generation, heat inputs, CO_2, SO_2 and NO_x emissions to EPA. In the sample, 218 out of 300 thermal generators are covered by CEMS.

the heat rate is, the more efficient a generator is. It is relatively flat within the operating range of a generator, but can be higher during startups[21].

	Coal	Natural Gas		
		Combined Cycle	Combustion Turbine	Steam Turbine
Nameplate Capacity(MW)	638.61	414.79	72.53	254.10
	(192.96)	(277.91)	(44.13)	(215.74)
Years in Operation	26.00	16.15	19.50	43.64
	(11.38)	(11.11)	(12.63)	(8.08)
Heat Rate(MMBTU/MWH)	9.55	7.38	11.90	10.99
	(0.62)	(1.35)	(4.26)	(2.82)
CO_2(Ton/MWH)	1.16	0.51	0.72	0.80
	(0.20)	(0.13)	(0.29)	(0.33)
SO_2(Pound/MWH)	5.80	0.01	0.03	0.02
	(3.86)	(0.02)	(0.05)	(0.03)
NO_x(Pound/MWH)	1.36	0.34	2.24	1.76
	(0.69)	(0.26)	(2.61)	(1.06)
Median Ramping Time[22]	Over 12H	12H	1H	12H

Notes: This table compares the characteristics of different types of thermal generators. The data for nameplate capacity, years in operation and ramping time come from EIA-860 forms. The heat rates and emission rates are calculated by the author as described in the text. Standard deviations are reported in the parentheses.

Table 2: Summary Statistics

Table 2 compares thermal generators along several dimensions. In general, coal generators tend to be larger, more polluting and ramp up more slowly than natural gas generators. Within natural gas generators, there are several different technologies. Combustion turbine, a.k.a. gas turbine, uses high-pressure gas generated from fuel burning to drive the turbine. Steam turbine works similarly except water is used instead of air. Most of the steam turbine generators were built in the 1980s and 1990s. The technology has not seen much improvement since then. By contrast, the efficiency of the combustion turbines has been constantly evolving. The heat rates of the most recent ones are only one fourth of the heat rates of the most ancient ones. As a result, there is a wide variation in the heat rates of the combustion turbines. Besides, combustion turbines are also the fastest to respond to changing demand. Therefore, they are often used as peaking plants. The relatively new combined-cycle gas turbines combine these two thermodynamic cycles together to improve the efficiency of the energy conversion. As a result, the heat rates of combined-cycle generators are on average smaller than those of combustion turbines and steam turbines alone.

[21] More than half of the startup costs are fuel costs incurred to warm up the generator. The startup cost varies by technology and the size of the unit.

[22] Ramping time is defined as the minimum amount of time required to bring a generator from cold shutdown to full load. It's coded into four categories: 10 minutes, 1 hour, 12 hours and over 12 hours. I obtain this information from 2013 EIA-860 form, since it is only available after 2013.

4.3 Electricity Demand

The hourly demand data at eight weather zones are obtained from ERCOT[23]. The data is derived by aggregation of meter data and include transmission and distribution losses. The use of demand at weather zones instead of the entire region is to capture the spatial distribution of the demand. This geographical distribution may affect generation outcomes, especially in view of transmission constraints. In addition to regional variations, electricity demand also exhibits systematic seasonal and diurnal patterns. In order to examine the impact over the entire span of the demand distribution, the sample period is selected such that both winter and summer months are covered under the two market organizations.

4.4 Cost Data

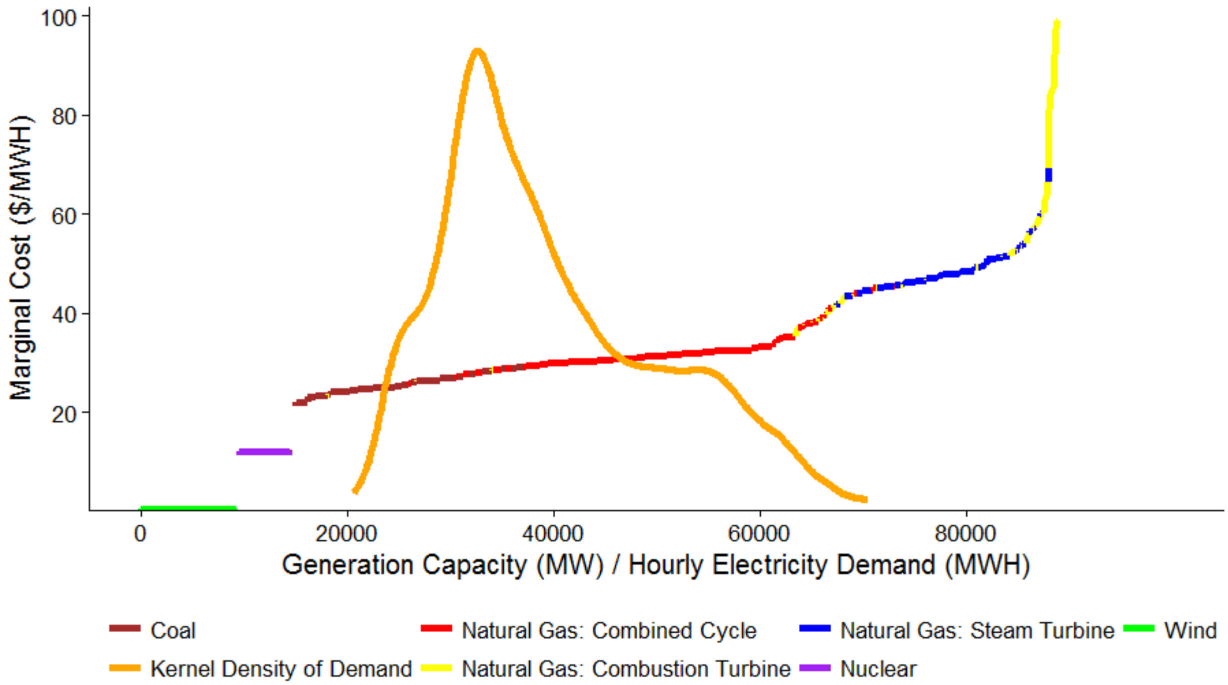
Cost structure in the electricity industry is relatively straightforward and well understood. For wind generators, the marginal cost for producing 1 more MW is essentially zero. For nuclear power plants, the marginal cost can be estimated by adding up the fuel cost and the variable operating and maintenance cost. I use EIA (2011)'s fuel cost estimate of \$7.01 and ERCOT (2012)'s VOM estimate of \$5.02 to get the marginal cost of nuclear units at \$12.03. To estimate the marginal cost for thermal generators, I take the standard approach commonly used in the economic literature (Wolfram (1999), Borenstein et al (2002), Mansur (2008)). The methodology is based on the following elements: (1) the heat rate of each generator; (2) fuel prices; (3) variable operating and maintenance costs (VOM); (4) the emission rates of each generator; and (5) emission allowance prices. Appendix A.3 provides more details on the data sources of the components other than heat rates and emission rates. For each generator i at time t, marginal cost is calculated using the following formula.

$$\mathrm{MC_{it}}=\mathrm{Heat\ Rate_i}\times\mathrm{Fuel\ Price_{it}}+\mathrm{Pno_{xt}}\times\mathrm{NOx_i}+\mathrm{Pso_{2t}}\times\mathrm{SO_{2i}}+\mathrm{VOM_i}$$

Figure 4 plots the marginal cost curve using generators' average marginal costs and the observed maximum hourly net generation as their capacity during the sample period. There are considerable heterogeneities in the marginal costs across generators of different fuel and technology types. Wind and nuclear power gets ahead of thermal generators on the marginal cost curve. Among thermal generators, coal generation is in general cheaper than natural gas generation, and combined-cycle generation is cheaper than generation from combustion

[23] A weather zone is a geographic region designated by ERCOT in which climatological characteristics are similar for all areas within such region. There are eight weather zones: coast, west, far west, east, north, north central, southern and south central.

turbines and steam turbines. I also overlay on the same graph the distribution of hourly electricity demand. For most realizations of demand, coal and combined-cycle natural gas generators will be on the margin, while during peak hours, the marginal unit is typically either a combustion turbine or a steam turbine.



Notes: This figure plots the marginal cost curve using generators' observed maximum hourly net generation as their capacity and average marginal costs during the sample period (Jun 1st 2010 - Aug 31st 2011). It also shows the kernel density of the total hourly electricity demand for the same period. See the text for details.

Figure 4: Marginal Cost Curve and Distribution of Demand

5 Empirical Strategy

The main objective of the empirical analysis is to measure the changes in market efficiency and social welfare due to the market redesign. This section will first discuss how market efficiency is measured in electricity generation and then introduce the econometric approach I use to quantify the changes.

Figure 5 provides a hypothetical example illustrating the efficiency change. As common in the literature, electricity demand is treated as perfectly inelastic in the short-run. The swings in demand are driven by exogenous forces, such as temperature and human activity. Since generation of electricity has to meet demand for electricity at every second, there is no inefficiency from quantity distortion under either market design. Any change in market efficiency will be reflected as changes in the generation cost to serve the same demand. The example in Figure 5 depicts a hypothetical efficiency gain under the centralized market. The MC curve lines up the installed generating capacity in the order of increasing marginal costs, representing the theoretical efficient supply. The actual supply, however, will deviate from the MC curve. A generator is operating out of the "merit order" if it is called on to help meet n megawatts of demand although it is not the n cheapest megawatts of the installed capacity based on its marginal cost. The grey area shown in the graph indicates the out-of-merit cost under the bilateral market. It is simply the additional production cost relative to the cost of dispatching the cheapest units. Out-of-merit cost occurs for many reasons. For example, transmission constraints may make it infeasible to utilize the least-cost units[24]. Failure to identify congestion externality and the exercise of market power, as explained in Section 3, are two important contributors to the out-of-merit cost. If the centralized market brings the supply closer to the MC curve, as shown in this example, then the slash area indicated in Figure 5 will be the resulting productive efficiency gain. In contrast with some earlier literature (e.g., Borenstein et al (2002)), I will not directly compare the generation cost with the cost implied by the theoretical efficient supply, but rather look at the difference in generation costs under the two designs.

In order to measure the changes in generation costs, I need to create a credible counterfactual of what would be the outcome had ERCOT not redesigned its market. One way of doing this is to simulate the market with an engineering model. However, this approach requires modeling the electrical grid in detail and making strong assumptions on firms' information set and their strategic behavior. This poses real challenges as both the transmission network and the competitive interactions are extremely complex. Another inclination might be to directly compare the generation cost before and after the redesign. This seems to be a tempting option, given that there are few changes in the market during the relatively short period preceding and following the redesign. In Appendix A.4, I show that the span of demand and fuel prices are indeed comparable pre and post redesign. Besides, there are no major changes in market capacity. Nevertheless, a simple "before-and-after" comparison is problematic, because demand and fuel prices are never identical even within a very short period. For example, the distribution of the electricity demand varies across time. In partic-

[24]Other reasons include generator outages and dynamic constraints. Plants periodically go off-line for maintenance and occasionally experience forced shutdown, causing more expensive units to fill the gap. Besides, the start-up time and ramping costs also matter in determining the most economical dispatch, as shown by Mansur (2008) and Reguant (2014). Hence, the mere presence of the out-of-merit cost does not necessarily indicate efficiency loss.

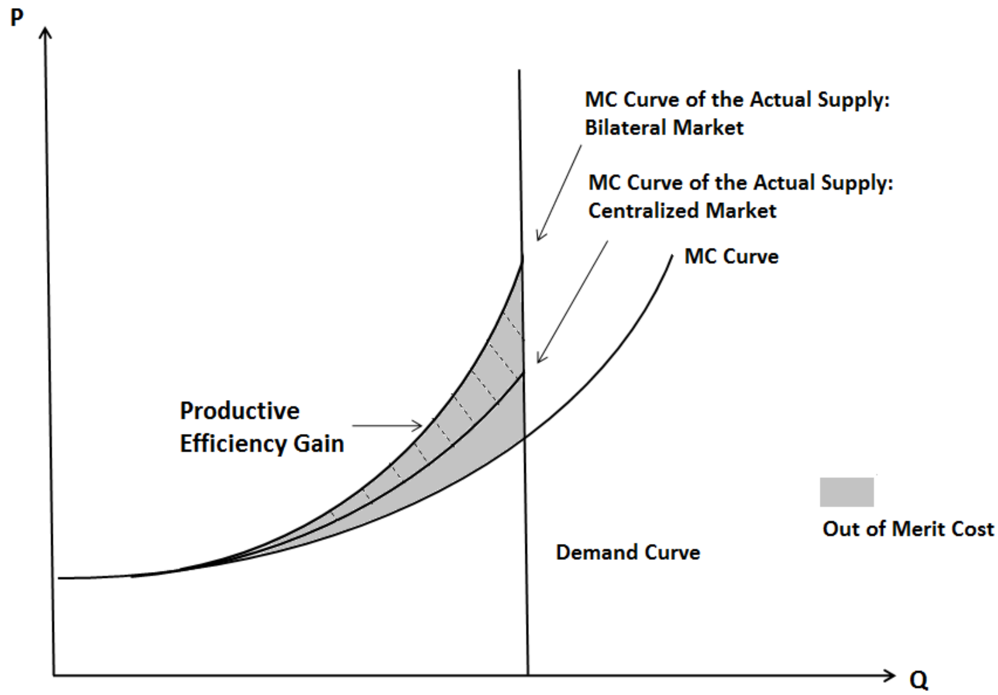
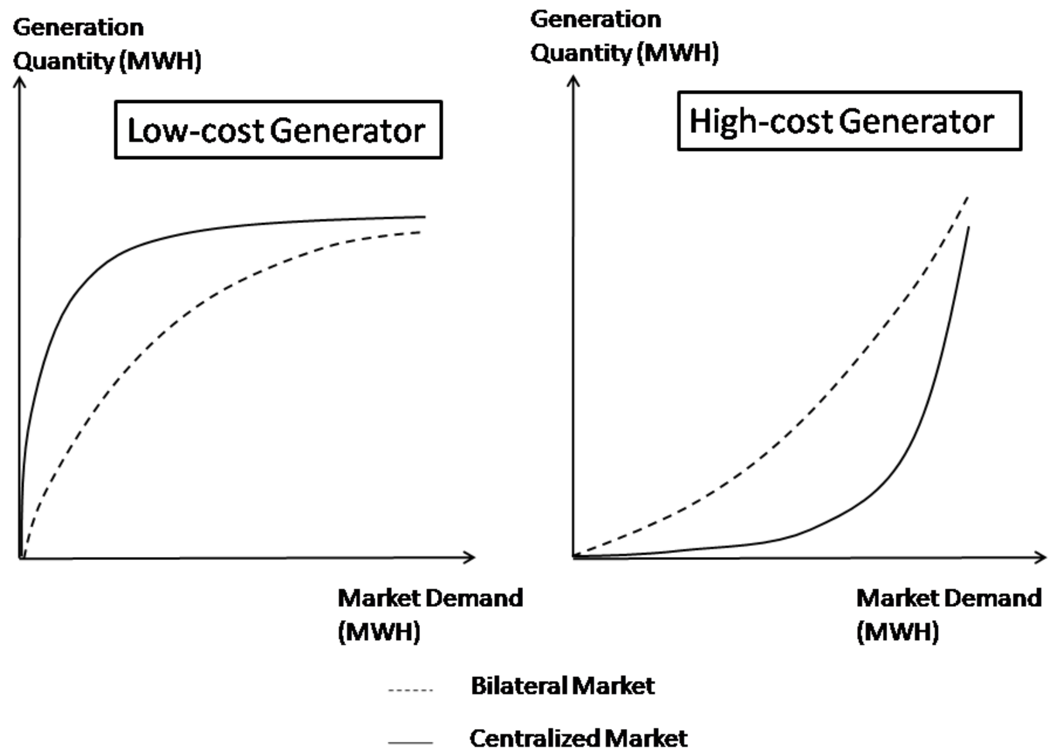


Figure 5: An Illustration of A Hypothetical Efficiency Gain Under the Centralized Market

ular, during the sample period, the average demand post redesign is lower than the average demand before the redesign. Without taking this into account, we are likely to misattribute the cost reduction from demand changes to the difference in organizational forms.

I therefore rely on an econometric approach that estimates a flexible function of generation quantity on market demand and fuel prices for each generating unit separately before and after redesign. The resulting estimates allow me to construct the counterfactual generation and then use the marginal costs to obtain the overall change in generation cost. The idea is that if the centralized market results in improvement in market efficiency, we should expect that in general low-cost generators generate more and high-cost generators generate less given the same market demand and fuel prices. Figure 6 illustrates such a case. Hence, we can measure the change in generation quantity for each generator by first estimating the generation curves. This approach is similar to Davis and Hausman (2016).

I treat nuclear power and wind as non-dispatchable units that do not change with the market redesign. For nuclear power, due to its low marginal costs and limited capability to follow load, it almost always runs at full capacity unless having an outage. For wind



Notes: Assuming constant fuel prices, this figure provides an example of changes in generation curves for generators of low versus high costs if the centralized market improves efficiency.

Figure 6: An Illustration of Changes in Generation Curves for Generators of Different Costs

generators, generation quantity is determined by the availability of the wind. Although wind generation can be curtailed when transmission is congested and market redesign may improve the integration of wind resources into the market, Appendix A.5 shows that there is no evidence of such improvement. Therefore, the subsequent analysis will only focus on thermal generators.

Let $ThermalDemand_{jt}$ be the residual demand for thermal generators after subtracting supply from wind, nuclear and others at weather zone j in time t[25]. I separate $ThermalDemand$ at each zone into 12 mutually exclusive equal-frequency bins[26]. Let b_{jk} (j=1,...,8; k=1,...,12) denotes the left end point of bin k for demand in weather zone j . Let

[25]Others include biomass, petroleum coke, distillate fuel oil, solar and electricity storage.

[26]The optimal number of bins is selected by using leave-one-out cross validation. Specifically, given the number of bins, I estimate the corresponding model on (N-1) observations (hours) and predict the outcomes for the remaining one. I repeat the process for all N combinations and calculate the prediction errors. I experiment with different number of bins and choose the one that minimizes the mean squared error.

$$B_{jk}(ThermalDemand_{jt}) = \begin{cases} ThermalDemand_{jt} - b_{jk} & \text{if } ThermalDemand_{jt} > b_{jk} \\ 0 & \text{if } ThermalDemand_{jt} \leq b_{jk} \end{cases}$$

For each thermal generator i, I will estimate a continuous piecewise linear model with respect to demand at each zone, using data from pre- and post- redesign period separately:

$$\text{Gen}_{it} = \beta_{0i} + \sum_{j=1}^{8} \sum_{k=1}^{12} \beta_{ijk} B_{jk}(ThermalDemand_{jt}) + \boldsymbol{\phi_{ih}} + \boldsymbol{\delta_{iw}} + \alpha_{1i} P_{Ng-Coal,t} + \alpha_{2i} P^2_{Ng-Coal,t} + \epsilon_{it} \tag{1}$$

I also include hour fixed effects $\boldsymbol{\phi_{ih}}$ and day-of-week fixed effects $\boldsymbol{\delta_{iw}}$, as well as the quadratic form of the price differences between coal and natural gas to control for the effect of fuel prices on the substitution between coal and natural gas generation[27]. All coefficients are generator specific, and different before and after. Overall, there are 10,646 hourly observations in the sample. For each generator, 256 coefficients are estimated, resulting in a total of 76,032 coefficients for the 297 generating units in the sample. Using the estimates from the pre-redesign period to form the counterfactual, I can evaluate the change in generation quantity for each generator i at hour t of the post-redesign period. In the mathematical form,

$$\Delta \text{Gen}_{it} = (\hat{\text{Gen}}_{it} \mid \hat{\boldsymbol{\theta}}_{\boldsymbol{i}}^{post}, \boldsymbol{X}_{\boldsymbol{t}}^{post}) - (\hat{\text{Gen}}_{it} \mid \hat{\boldsymbol{\theta}}_{\boldsymbol{i}}^{pre}, \boldsymbol{X}_{\boldsymbol{t}}^{post})$$

The standard errors are estimated using simple block wild bootstrapping method where a "block" consists of 24 hours of a calender day. This method allows for arbitrary correlations across generators and serial correlations up to 24 hours.

6 Results

6.1 The Effect of Redesign on Generation Quantity

I present the results by first reporting the average hourly changes in generation quantity and then showing how the changes vary with demand levels and fuel prices. In light of the heterogeneity of costs across generators, I aggregate the results according to generators' fuel and technology types.

[27]Including higher-order polynomials of fuel price differences yields similar results.

Table 3 reports the estimated average hourly changes in generation quantity over all hours in the post-redesign sample period. The baseline column shows the results from the estimation of equation (1). On average, coal generation–the least costly resource–increases by 511.2 MWh while there is a similar reduction from natural gas generators. To provide more perspective on the magnitude of the change, the overall coal generating capacity in ERCOT is 19,819 MW. Therefore, the increase in coal generation is roughly a 3% raise in the utilization of the overall coal capacity. Within natural gas generators, the decrease in generation comes from both combined-cycle and steam-turbine natural gas. Interestingly, combustion turbine generators also experience an increase in production, although they do not have the lowest marginal costs. This increasing usage can be explained by their ability to adjust production quickly to serve peak loads. We will see a more nuanced picture of these changes later on.

Fuel Type	Baseline Model	Alternative Models				
		(1)	(2)	(3)	(4)	(5)
Coal	511.2	524.2	508.2	509.1	701.8	480.4
	(71.2)	(68.6)	(75.6)	(73.5)	(67.2)	(71.5)
Natural Gas: CC	-353.4	-350.2	-352.7	-357.2	-556.1	-423.7
	(57.8)	(57.8)	(60.6)	(60.0)	(53.2)	(55.0)
Natural Gas: CT	106.8	86.5	106.2	113.6	110.0	95.7
	(15.4)	(13.6)	(15.2)	(16.0)	(16.7)	(15.3)
Natural Gas: ST	-306.3	-301.1	-303.3	-314.8	-292.8	-346.1
	(29.8)	(30.0)	(28.9)	(31.2)	(31.3)	(27.4)
Quadratic Fuel Price Difference	Y	Y	Y	Y	N	Y
Quadratic Fuel Price Ratio	N	N	N	N	Y	N
Quadratic Temperature	N	Y	N	N	N	N
Standard Deviation of Demand	N	N	Y	N	N	N
One-hour Lagged Demand	N	N	N	Y	N	N
Truncation	N	N	N	N	N	Y

Notes: This table reports the estimates of the average hourly changes in generation quantities measured in MWh, using equation (1) and several alternative models. For all models, hour and day-of-week fixed effects are included. The sample consists of 10,464 hourly observations and 297 generating units. Standard errors reported in the parentheses are estimated using simple block wild bootstrapping method.

Table 3: The Effect of Market Redesign on Average Generation Quantities

The remaining columns in Table 3 report robustness results from several alternative specifications. First, temperature may affect thermal generators' efficiency. Therefore, I include the quadratic form of temperature in the alternative model (1)[28]. Second, generators differ

[28]Temperature data are collected from National Centers for Environmental Information (NCEI)'s Inte-

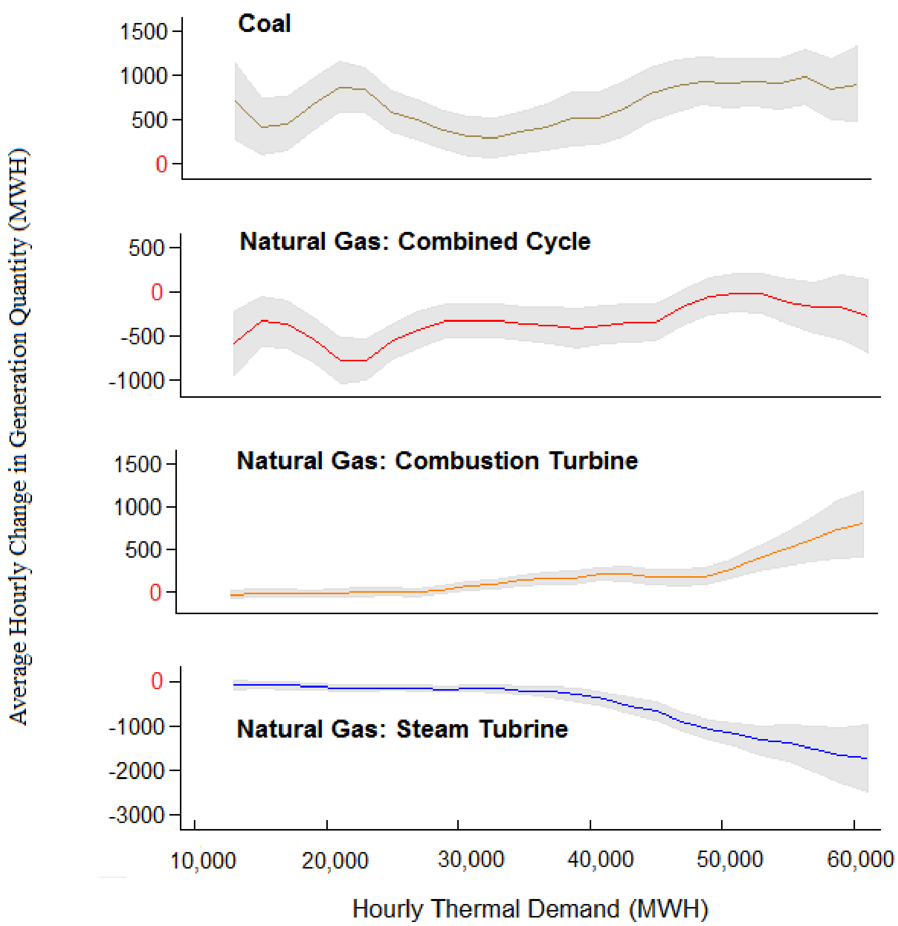
in their ability to adjust outputs in response to load fluctuations. To capture this dynamic constraint, I include the daily variance of the demand and one-hour lagged demand in model (2) and (3). Third, in model (4), I experiment with a different measure of the fuel price gap, i.e. the ratio of natural gas price to coal price. And finally, in model (5), I truncate the predictions which are either below zero or beyond the generators' nameplate capacities. About 25% of the predictions are truncated, but only 5% of them are more than 5 MW away from the thresholds. The results from these alternative specifications are shown in Table 3. Although the magnitudes differ slightly, the overall pattern is consistent with the baseline results. In addition, in Appendix A.4, I perform two placebo tests and find that these changes are not seen in other years when there is no change in the market organization.

Next, I explore how these changes in generation quantities vary with demand levels. Figure 7 plots the average hourly change in generation quantity at different thermal demand levels, assuming fuel prices are at their post-redesign averages. Again, I show the results separately by fuel and technology types. For coal generation, the increase persists throughout the entire span of demand. The increase tends to be larger when demand is higher. The increase is also larger when thermal demand is at around 20,000 MWh. That's where coal and combined-cycle natural gas split on the marginal cost curve. For combined-cycle natural gas generators, the magnitude of the change is not always the same. When demand is relatively low, they are displaced by cheaper coal. However, when demand is relatively high, they become the relatively cheaper resource compared to the more costly steam turbine generators. As a result, the decrease in generation becomes smaller and insignificant from zero.

For combustion and steam turbines which mostly serve peak loads, the pattern of the changes with respect to demand is more revealing. Although Table 3 shows that on average generation from combustion turbines increases and generation from steam turbines decreases significantly, the relationship is quite heterogeneous with respect to demand. When demand is low, they seldom operate, and hence the effect of market redesign on them is insignificant. As demand increases, there is a clear surge in generation from combustion turbines and a substantial decrease in generation from steam turbines. This is in line with their differences in marginal costs. The increase in generation from combustion turbine is also due to its ability to ramp up and down quickly. Hence, they can offset generation from steam turbines when coal or combined-cycle natural gas generators are unable to. Overall, the change in

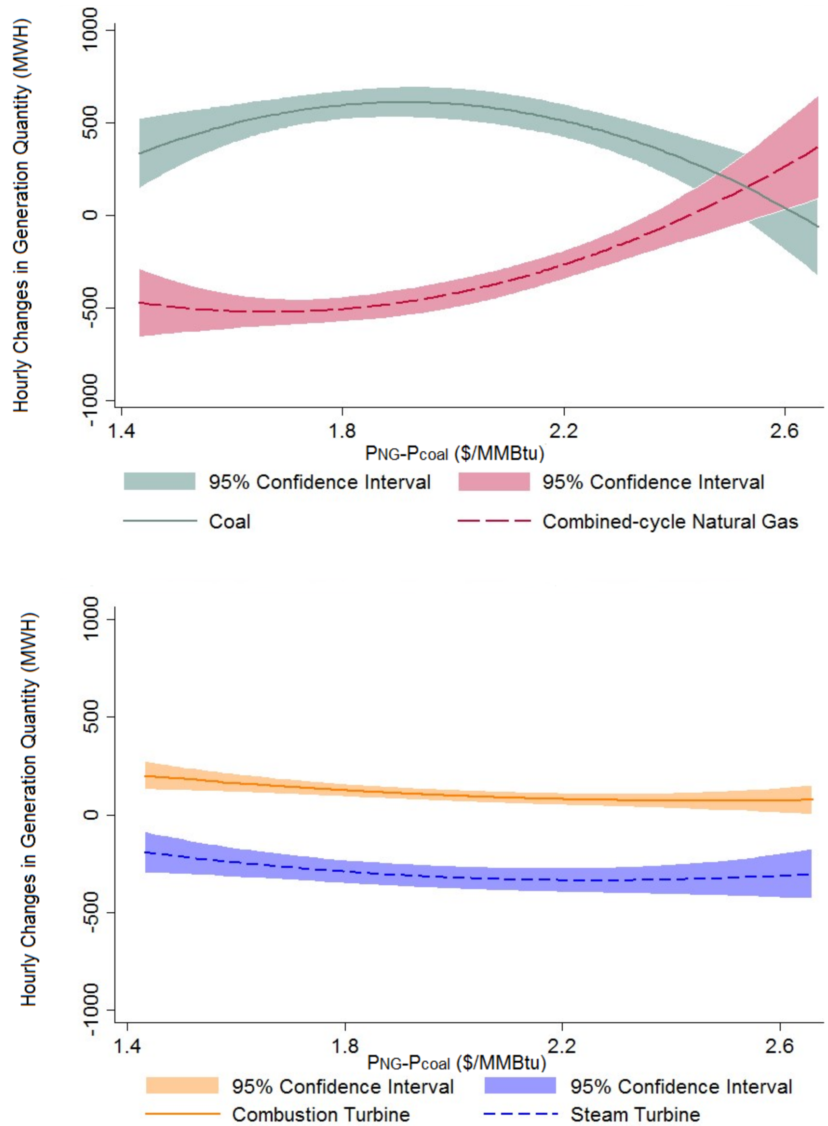
grated Surface Database. I use the average hourly temperature of the three largest cities in Texas, i.e. Houston, Dallas and San Antonio.

generation pattern with respect to demand further supports the role cost plays in determining the generation outcomes under the centralized market.



Notes: These figures plot the average hourly changes in generation quantity at different demand levels. The prices of natural gas and coal are fixed at their post-redesign averages, i.e. \$ 4.17 per MMBtu for natural gas and \$ 2.17 per MMBtu for coal. The grey area indicates 95% confidence intervals.

Figure 7: Average Hourly Changes in Generation Quantity by Demand Levels



Notes: This figure shows the hourly changes in generation quantity over the price differences between natural gas and coal. Demand is assumed to be at its post-redesign average at each zone, which adds up to 31,196 MW for the overall thermal demand. The shaded area indicates 95% confidence intervals.

Figure 8: Hourly Changes in Generation Quantity and Fuel Price Differences

Finally, I examine how the changes in generation vary with the price differences between natural gas and coal. Figure 8 shows the changes in generation quantity over fuel price differences when demand at each zone is assumed to be at its average of the post-redesign sample period. The change in coal generation has an interesting inverse-U shape. When the price gap between natural gas and coal gets larger, there are initially more coal-natural gas switches due to the cost advantages coal has. However, the effect declines as the gap continues to enlarge. The explanation for it is that when the price difference between coal and natural gas is sufficiently large, market participants can easily identify coal as part of the least costly allocation under the bilateral market. As a result, there is less room for improvement under the centralized market. Hence, all else equal, the change in coal generation becomes smaller when the price gap is sufficiently large. This pattern is also supported by the changes within natural gas generators. With marginal costs close to coal, combined-cycle natural gas generators experience changes in generation opposite to coal. In contrast, fuel price difference has a relatively small effect on combustion and steam turbines which are further away from coal on the marginal cost curve.

6.2 The Effect of Redesign on Generation Cost

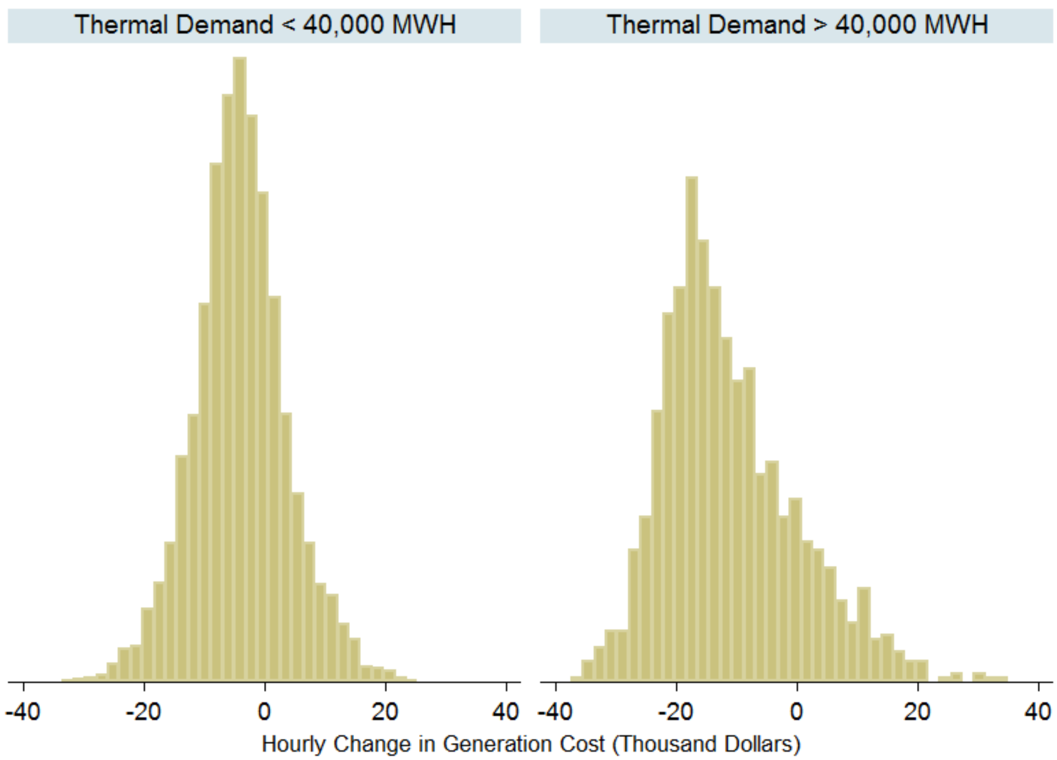
In this section, I quantify the change in the generation cost due to the market redesign. To do so, I use each generator's estimated quantity changes from the previous section and their average marginal costs of the post-redesign period[29]. The overall change in generation cost at hour t is the sum of changes from all the generators, i.e.,

$$\Delta Cost_t = \sum_i \Delta Gen_{it} * MC_i$$

Averaging across all hours, the cost reduction is estimated to be \$5,062 per hour with a bootstrapped standard error of \$ 1,026 for the nine months post redesign. The reduction is roughly 0.5% of the average total hourly generation cost. The changes vary substantially from hour to hour. Overall, for about 75 % of the hours, the generation cost is estimated to be lower than what would have been without the market redesign. Figure 9 shows the distribution of hourly changes in generation cost for low demand hours and high demand hours separately. In general, the cost reduction is higher during high demand hours than

[29]This approach assumes no start-up cost and constant marginal costs. An alternative approach is to run regressions similar to equation (1), but with a different dependent variable – the heat inputs. In this way, I can capture any nonlinearity in the fuel usage over the operational range of a generator. With the estimated changes in heat inputs, I can apply the fuel prices to derive the changes in fuel costs. This approach, though, does not take into account other cost components, such as emission allowance costs and VOM. To deal with this, I estimate the non-fuel cost changes using the results from the original generation regressions and the non-fuel portion of each generator's marginal cost. The resulting estimate for the overall cost change is \$8,332 per hour on average for the nine months post redesign. This is higher than the estimate without start-up cost, which corroborates with the finding that combustion turbines, which have the lowest start-up cost, generate more under the centralized market. Although this approach is able to capture the start-up costs, the limitation is that only generators covered in CEMS data have heat input information. Thus I have to limit the sample to those generators, which are about two thirds of all thermal generators.

low demand hours.



Notes: This figure shows the histograms of the estimated changes in generation cost for hours of low demand (thermal demand $<$ 40,000 MWh) and hours of high demand (thermal demand $>$ 40,000 MWh) separately.

Figure 9: Distribution of the Estimated Changes in Generation Cost: Low v.s. High Demand

6.3 The Effect of Redesign on Emissions and External Costs

Although the centralized market leads to a significant reduction in generation cost, it also affects welfare through the changes in emissions. From a social perspective, the private efficiency gain has to be weighted against the changes in external costs of emissions.

I focus on three pollutants: CO_2, SO_2 and NO_x. To estimate the change in emissions of each pollutant, I again use the estimated changes in electricity generation quantity and each generator's emission rate. For pollutant j, the change in emission quantity at hour t is the sum of changes from all the generators, i.e.,

$$\Delta \text{Emission Quantity}_{jt} = \sum_i \Delta \text{Gen}_{it} * \text{Emission Rate}_{ij}$$

The second column in Table 4 reports the average hourly changes in emission quantities. Averaging over all hours, the change in CO_2 emission quantity is 350.5 tons per hour, roughly a 1.3% increase in hourly CO_2 emissions. The rise in CO_2 emission is not surprising given the increasing usage of coal generators. On average, coal power plants emit 1.16 ton of CO_2 per MWh, while natural gas plants only emit 0.65 ton of CO_2 per MWh. For SO_2 and NO_x, the changes in emission quantities are much smaller due to lower emission rates. On average, SO_2 and NO_x emissions decrease by 0.268 and 0.239 ton per hour. Notably, the change in SO_2 emission is negative despite that on average coal generators emit far more SO_2 than natural gas generators. The change in SO_2 emission is primarily driven by relative changes within coal generators. Unlike CO_2 emission rates, which are similar across coal generators, the SO_2 emission rates are quite diverse, ranging from 0.1 pound/MWh to 14.8 pound/MWh. This variation is a reflection of heterogeneity in coal power plants' compliance strategy: whether a scrubber is installed and what kinds of coal are used. As a result, when high sulfur emitters are displaced by low sulfur emitters within coal generation, the overall SO_2 emission can decrease. However, the change is not significant, given the relatively large standard errors.

In a similar way, I can calculate the changes in external costs associated with the emissions. For pollutant j, the change in the external cost at hour t can be expressed as follows:

$$\Delta \text{External Cost}_{jt} = \sum_i \Delta \text{Gen}_{it} * \text{Emission Rate}_{ij} * \text{Marginal Damage}_{ij}$$

To calculate the monetary value of emissions, I need to select appropriate measures for marginal damages. For CO_2, EPA (2010) compiles estimates on the social costs of carbon for use in regulatory analysis[30]. Depending on the assumed discount rates, the marginal damage value of CO_2 ranges from \$ 5 in the low value scenario to about \$ 21 in the middle range and \$ 35 on the high end. For SO_2 and NO_x, choosing the right estimates is more nuanced. Unlike CO_2 which is a uniformly mixed pollutant, SO_2 and NO_x have relatively localized and direct impacts. Hence, the geographic distribution of emissions matters for the evaluation. For this reason, I use Jaramillo and Muller (2016)'s marginal damage estimates to calculate the emission costs of SO_2 and NO_x. The estimates are spatially differentiated at county level. For SO_2, the marginal damage ranges from \$ 5,906.1 to \$ 32,128 per ton, while for NO_x, the marginal damage ranges from \$ 1,098.5 to \$ 5,961.1 per ton.

[30]Since the market redesign happened in 2010, I use EPA (2010)'s estimates instead of the more recent ones.

Pollutant	ΔEmission Quantity (Ton/Hour)	Marginal Damage ($/Ton)	ΔExternal Cost ($/Hour)
		5	1,752.5
			(313)
CO_2	350.5	21	7,360.5
	(62.6)		(1,314.6)
		35	12,267.5
			(2,191)
SO_2	-0.268	5,906.1 - 32,128	8,305.5
	(0.25)		(3,789.4)
NO_x	-0.239	1,098.5 - 5,961.1	-1,478.2
	(0.05)		(206.2)

Notes: This table reports the average hourly changes in emission quantities and the associated changes in external costs. Standard errors reported in the parentheses are estimated using simple block wild bootstrapping method.

Table 4: Average Hourly Changes in Emission Quantities and External Costs

The rightmost column in Table 4 reports the resulting estimates of the average hourly changes in external costs of emissions. With different estimates of the social cost of carbon, the external costs of CO_2 emissions range from \$ 1,752.5, to \$ 12,267.5 per hour respectively. The external costs of SO_2 and NO_x emissions are estimated to be \$ 8,305.5 and \$ -1,478.2 per hour. Taken together, the environmental costs of emissions exceed the private generation cost savings at \$ 5,062 per hour. There are two caveats when interpreting the emission results. First, cap and trade programs may make power plants internalize some of the external costs. In Texas, CO_2 emissions are not regulated, but SO_2 and NO_x are subject to cap and trade programs. However, only a very small portion of the social costs is internalized, since the average allowance prices for SO_2 and NO_x are just \$ 8.4 and \$ 275.5 per ton during the sample period. A second caveat is that I implicitly assume that all the environmental damages are confined to Texas and there are no changes in the emissions outside of Texas as a result of this redesign. However, if the cap and trade programs are binding, then the emission increases in Texas result in emission reduction somewhere else in the country. Therefore, there might be no aggregate change in emission quantity. But given the spatially heterogeneous marginal damages, the redistribution of the pollutants may still affect welfare. A thorough analysis of the spillover effect is beyond the scope of this paper. Nevertheless, even leaving aside the impacts of SO_2 and NO_x, the external cost from CO_2 emissions will completely offset the private efficiency gain, as long as the marginal damage of CO_2 is greater than \$ 15 per ton.

7 Discussion

The productive efficiency gain and the increase in external costs found in the previous sections are both statistically significant and economically large. In this section, I address two questions: First, is the magnitude of the generation cost reduction in line with what ERCOT expects? Second, is the redesign warranted on a cost-benefit ground?

The answer to the first question is Yes, but somewhat smaller. Prior to the implementation of the new market design, ERCOT retained Tabors Caramanis & Associates (TCA), and CRA International, Inc. and Resero Consulting (CRA/Resero) to conduct cost-benefit assessments of the new market design back in 2004 and 2008. The two studies estimate the annual production cost reduction to be $ 66.8 million and $ 48.0 million respectively. Corroborating these studies, back-casts performed by the ERCOT staff post redesign suggest production costs would have been lower by $ 90 to $ 180 million in 2008 had the centralized market been in place (ERCOT, 2011a). Their analysis uses offers submitted by market participants during a market trial and calculates the cost difference for one selected hour in 2008. In the previous section, I find the average hourly cost saving to be $ 5,062, which translates into $ 44.3 million on an annual base. This number is on the same order of magnitude suggested by ERCOT, but smaller than the aforementioned estimates.

Benefit	
Generation Cost Saving($m/year)	44.3 (Author's Calculation)
Ancillary Services Cost Saving($m/year)	17.0 (ERCOT, 2011a)
Savings from Improved Generation Siting($m/year)	33.6 (CRA/Resero, 2008)
Cost	
One-time Implementation Cost($m)	548.6 (ERCOT, 2011b)
Incremental Operational Costs($m/year)	14 (CRA/Resero, 2008)
Environmental Cost($m/year)	75.2-167.3 (Author's Calculation)

Notes: This table lists the benefits and costs of ERCOT's market redesign.

Table 5: The Cost-Benefit Analysis of ERCOT's Market Redesign

To answer the second question requires a thorough analysis of the costs and benefits associated with the market redesign. On the benefit side, generation cost saving is just one part of the story. The new market redesign is also expected to reduce costs from ancillary services which are services to ensure the reliability of the grid. The cost saving for ancillary services is estimated to be $ 17 million per year. Additionally, in the long run, the centralized market can lead to improvement in siting of new resources through more transparent locational marginal prices. CRA/Resero (2008) estimates this benefit to be $ 33.6 million per year. On the cost side, aside from the external costs from increasing e-missions, implementing the new market design requires a one-time cost of $548.6 million as well as yearly recurring expenses of $ 14 million. Table 5 summarizes these benefit and cost components. Taken together, the picture emerges is that the redesign will be cost effective for the first 10 years of operation if the discount rate is no more than 7.5%, when environmental costs are not taken into account. For low estimates of carbon damages, it is still cost effective, but over a much longer horizon. However, for medium-to-high estimates of carbon damages, the society will surely undergo a welfare loss from this market redesign[31].

8 Conclusion

This paper examines the private and social consequences of a market redesign in the Texas electricity market. Using a flexible semi-parametric approach, I estimate the changes in generation for all generating units and quantify the associated changes in production costs and emissions. The primary finding of the paper is that the centralized market improves productive efficiency. This attests to the superiority of the centralized market at aggregating information and resolving congestion externalities, despite of concerns for market power. As more experience is gained at detecting market manipulation under the centralized market, we can expect the centralized market design to be more popular in electricity markets. Currently, all deregulated electricity markets in the U.S. have adopted the centralized auction market design. But worldwide there are still many electricity markets that have either not restructured their markets or adopted the bilateral trading model. The findings of this paper provide empirical evidence on the relative performance of the two market designs, and may serve as useful reference for those markets. For future research, cross-market comparison may help us better understand the drivers of different transition experiences.

This paper also finds that the market redesign in Texas has an unintended impact on emissions. The environmental cost of the redesign is not trivial. For moderate estimates

[31] One caveat to the extrapolation is that it's based on the market conditions from Jun 1st 2010 to Aug 31th 2011. During the subsequent years, natural gas prices have dropped from about $ 4/ MMBtu to less than $ 2/ MMBtu. The decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2014). On one hand, since some natural gas power plants, especially the combined-cycle plants, get ahead of coal on the merit order, we may not see as much displacement of natural gas generation by coal generation in the later years as in 2011. Hence, the environmental cost may be substantially lower in the later years than the estimates shown here. On the other hand, private cost savings from the market redesign may also be lower, given smaller differences in marginal costs among generators.

of the marginal damages of the emissions, the redesign no longer passes the benefit-cost test. This finding highlights the importance of accounting for environmental impacts when decisions are to be made in the energy market. It also underscores the necessity of aligning private cost and social cost, which can be achieved by introducing carbon pricing schemes or setting up appropriate emission caps.

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Appendix

A.1 ERCOT Market Operation

This section provides details on the market processes under the bilateral trading market and the centralized market.

A.1.1 Scheduling and Dispatch Under the Bilateral Trading Market

Before the redesign, ERCOT was a bilateral trading market. The operation of the market consists of two major phases[32].

1. Day-ahead scheduling process
   Load serving entities and generation resources negotiate privately with each other to buy and sell energy. The resulting bilateral contracts specify the transfer of electricity at negotiated terms such as duration, price, and time of delivery. In the day-ahead period, market participants are required to submit their "balanced schedules" to the ERCOT ISO through Qualified Scheduling Entities (QSEs) which are qualified by ERCOT to submit schedules for a portfolio of generators and power purchasers. These schedules specify the origins and destinations of power flows by congestion zone for each settlement interval, which lasts 15 minutes[33]. The scheduled resource production should not deviate the forecast demand beyond an established range. ERCOT analyzes the day-ahead schedules and notifies the QSEs of anticipated inter-zonal congestion. Market participants are allowed to adjust their schedules to relieve the forecasted congestion. Once the schedules are accepted by ERCOT, the generators are "physically" committed to produce the scheduled quantity unless being instructed to increase or decrease its production in the balancing market. Uninstructed deviation exceeding 1.5% of the QSE's schedule results in penalty payment (Sioshansi and Hurlbut, 2010). 95% of the overall generation is scheduled in this process.

2. Real-time balancing market
   During the day-ahead scheduling process, generation resources also submit balancing energy bids for adjusting their generation relative to their scheduled quantities. In real-time, ERCOT manages energy imbalance and transmission congestion between zones by intersecting the bidding functions separately for each zone. For intra-zonal

[32] There is also an adjustment period between the day-ahead period and the operating period.

[33] ERCOT divides its territory into 4 congestion zones. Congestion zone is a group of buses that have similar shift factors on commercially significant constraints. Dividing the entire grid into several congestion zones simplifies the modeling of the network.

congestion, ERCOT deploys resources based on the generic fuel cost factors and shift factors to resolve local transmission constraints.

A.1.2 Scheduling and Dispatch Under the Centralized Auction Market

Under the centralized market design, market participants put their generation resources at the disposal of ERCOT and they are centrally dispatched to minimize generation costs. The operation of the centralized auction market also consists of two phases.

1. Day-ahead operation
   In the day-ahead period, market participants submit offers to sell energy for each hour of the operating day. The supply offer may contain three parts: the startup offer, the minimum-energy offer and the energy offer curve. These offers are used in the day-ahead energy market. Participation in the day-ahead energy market is voluntary and does not physically commit a resource to come on-line. In 2011, day-ahead purchases account for approximately 40 percent of real-time load (Potomac Economics, 2012). After the completion of the day-ahead energy market, ERCOT executes a reliability unit commitment process to ensure that it has enough capacity committed to serve the forecasted load for the operating day.

2. Real-time operation
   While bilateral trades and the day-ahead energy market transfer *financial* responsibility among QSEs, the Security Constrained Economic Dispatch (SCED) program in the real time actually dispatches the resources. ERCOT utilizes a network operation model which represents the system with critical information on characteristics, ratings, and operational limits of all elements of the transmission grid. On-line resources are dispatched in economic order according to their submitted energy offer curves. The execution of SCED results in locational marginal prices at approximately 4,000 nodes[34].

A.2 Proof of Firm X's Optimal Strategy

Denote the quantities Firm X supplies at node B and C as Q_B and Q_C. The supply coming from node A is $300 + Q_B$. Hence, the residual demand for Firm X at node C is $Q_C = 600 - (300 + Q_B) - Q_B - 100(P_C - 8) = 1100 - 2Q_B - 100P_C$. Equivalently, $P_C = 11 - 0.02Q_B - 0.01Q_C$. To obtain $\mathrm{P_B}$, note that if we increase production at both A and B by 1 MW each, production at C can be reduced by 2 MW to meet the same level of

[34]Hence, the centralized market is also known as the "nodal market".

demand at C. The resulting prices, therefore, satisfy the relationship $P_A+P_B=2P_C$. Firm X's problem is:

$$\max_{Q_B\geq 0, Q_C\geq 0}(11-0.02Q_B-0.01Q_C-7.2)*Q_C+[2*(11-0.02Q_B-0.01Q_C)-5-9]*Q_B$$

The kuhn-Tucker conditions with respect to Q_B and Q_C are

$$\frac{\partial}{\partial Q_B}=8-0.08Q_B-0.04Q_C\leq 0$$
$$\frac{\partial}{\partial Q_C}=3.8-0.04Q_B-0.02Q_C\leq 0$$

Obviously, the equalities will not hold for both conditions. We must have

$$\frac{\partial}{\partial Q_B}=0$$
$$\frac{\partial}{\partial Q_C}<0$$

Hence, the profit-maximizing quantities are $Q_B=100$, $Q_C=0$.

A.3 Data Appendix

A.3.1 Coal Price

The majority of a power plant's coal is purchased through long-term contracts. Therefore, I use monthly plant-level coal receipt cost data from EIA-923 forms as the relevant coal prices. Some papers have used spot market coal prices and view them as the opportunity costs for coal plants (Mansur(2008), Mansur and White(2012)). I consider the spot market prices to be a bad approximation for opportunity costs for two reasons. First, there is evidence that the pass-through from spot market price to contract price for coal is fairly long and incomplete. Chu et al (2015) find that a 1% change in coal spot price leads to only an approximately 0.11% change in the contract prices received by power plants even after 12 months. Second, power plants consistently pay a sizable premium for contract coal over spot coal, which suggests that there are industrial or institutional barriers to take advantage of the cheaper spot coal. Joskow (1987) and Jha (2014) attribute this phenomenon to transaction-cost economics and regulatory induced risk aversion respectively.

The fuel receipt cost data are publicly available for regulated plants[35]. There are 16

[35]Unfortunately, access to the proprietary data form EIA requires US citizenship.

coal plants in ERCOT, 6 of which are regulated. For deregulated plants, I approximate the coal prices in the following way. Power plants in Texas purchase two types of coal: lignite from Texas and sub-bituminous coal from powder river basin in Wyoming. For lignite, only 2 regulated plants purchase it. Since lignite is produced within Texas, I assume that the transportation costs are relatively small while the content of the coal matters more for the price. Hence, I use the coal prices paid by plant Pirkey to approximate the prices for unregulated plants, since the coal characteristics purchased by Pirkey are close to the average lignite being purchased. For sub-bituminous coal, transportation cost is likely to be important. Therefore, I match every unregulated plant to its closest regulated neighbor and use the matched plant's coal price as its price. I am able to find a match for every unregulated plant within 100 miles. In the very few cases where no price data are available for certain month, I use the average price of the months preceding and following that month instead. Table A1 summarizes the matching outcomes. The final price for each plant is the quantity-weighted monthly receipt price.

Regulation Status	Coal Plant	Fuel Type	Matched Coal Plant
Deregulated	Big Brown	SUB	Gibbons Creek
		LIG	Pirkey
	Coleto Creek	SUB	J T Deely
	Limestone	SUB	Gibbons Creek
		LIG	Pirkey
	Martin Lake	SUB	Welsh
		LIG	Pirkey
	Monticello	SUB	Welsh
		LIG	Pirkey
	Oak Grove	LIG	Pirkey
	Sandow No 4	LIG	Pirkey
	Sandow No 5	LIG	Pirkey
	Twin Oaks Power One	LIG	Pirkey
	W A Parish	SUB	Fayette Power Project
Regulated	Gibbons Creek	SUB	
	Fayette Power Project	SUB	
	J K Spruce	SUB	
	J T Deely	SUB	
	Oklaunion	SUB	
	San Miguel	LIG	

Notes: This table shows the matching results for coal plants in ERCOT. As explained in the text, each unregulated plant is matched to a regulated plant for the same type of the purchased coal.

Table A1: Matching Outcomes for Coal Plants in ERCOT

A.3.2 Natural Gas Price

Daily Natural gas spot prices are collected from SNL Financial. I use prices at the Agua Dulce, Katy, Waha and Carthage hubs for units in the South, Houston, West, and North zones, respectively. Prices at the four hubs track each other very closely.

A.3.3 Variable Operation and Maintenance Costs (VOM)

Variable O&M costs include scheduled and forced outage maintenance, water supply costs and environmental equipment maintenance. I use the standard VOM costs published by ERCOT (ERCOT, 2012). These costs differ by fuel and technology type. For coal, combined-cycle natural gas, natural gas combustion turbine and steam turbine , VOM costs are \$5.02, \$3.19, \$3.94 and \$7.08 per MWh (in 2009 dollars) respectively.

A.3.4 Emission Allowance Price

Power plants in ERCOT are subject to three programs: the Acid Rain Program (ARP) and The Clean Air Interstate Rule (CAIR) annual SO_2 and NO_x programs. The ARP, established under Title IV of the 1990 Clean Air Act (CAA) Amendments, requires major emission reductions of SO_2 and NO_x, the primary precursors of acid rain, from the power sector. It is a nationwide program affecting large fossil fuel-fired power plants across the country. CAIR was finalized in 2005, and took effect in 2009 for NO_x and 2010 for SO_2. The CAIR SO_2 and NO_x annual programs require further reduction for large electricity generating units in 28 eastern states including Texas. Not all generating units are affected by these three programs. To determine each generating units' coverage status, I use information provided by EPA's Air Markets Program Data (AMPD) and cross check with The Code Of Federal Regulations Part 72 and 96 (40 CFR Part 72 and Part 96).

All three programs are cap-and-trade programs designed to allow power plants to arrange for the cheapest possible reductions among covered sources to meet the overarching cap. For each ton of SO_2 emitted, ARP compliance requires the surrender of 1 ARP allowance, while CAIR compliance requires an additional ARP allowances of prompt vintage. For each ton of NO_x emitted, 1 NO_x annual allowance has to be deducted. Generally, these allowances are traded among companies and individuals through brokers. I acquired daily SO_2 and NO_x allowance price indexes from a leading over-the-counter energy brokerage firm based in Texas. I use the last trading price each day as the revelent price. For non-trading days, I approximate the price by taking the average of the prices from the two trading days preceding and following that day.

Compared to the fuel cost, the emission cost makes up a very small portion of the variable cost. For coal power plants, emission cost on average counts for only 0.96% of the marginal cost. And for natural gas generators, this figure is less than 0.3%.

A.3.5 Wholesale Electricity Price Data

From ERCOT, I also collect the real-time post-redesign electricity prices at four hubs: Houston, North, South and West. A hub's price is the simple average of the locational marginal prices (LMPs) of nodes within that hub[36]. The hub prices will be the same throughout the system if no congestion exists. However, if congestion does exist, LMPs will differ from node to node, and so will the hub prices. Therefore, I define an hour to be congested if the electricity prices at the four hubs are not the same. Congestion is quite common. Of all the hours in the post-redesign sample period, about 60 % are congested.

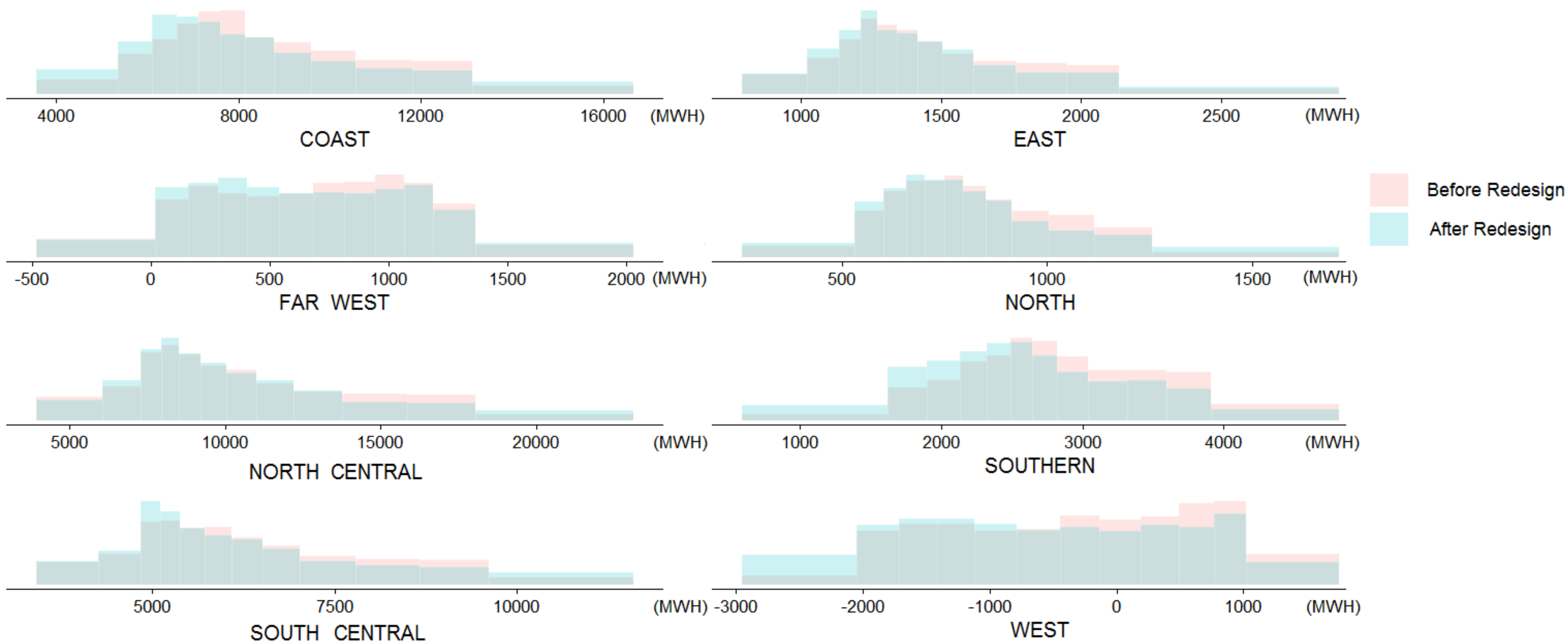
A.4 Additional Results and Robustness Checks

This section contains additional evidence that supports the validity of the empirical approach and robustness of the findings. First, I show that although the market conditions pre and post redesign are not exactly the same, they are quite comparable: the span of the demand at each zone overlaps; the changes of fuel prices are moderate; and entry and exit of generators do not exert a significant impact on the market. Second, I provide further evidence showing that the observed changes are unusual and not seen in other years when there is no market redesign.

A.4.1 Comparison of Demand

Figure A1 compares the distributions of demands at all eight weather zones pre and post redesign. To be consistent with the main specification, demand at each zone is divided into 12 equal-frequency bins based on the entire sample so that the number of observations falling into each bin is the same. Comparing the distributions before and after the redesign, we can see that they all have observations in each bin. The common support enables the estimation of the parameters for each bin both pre and post redesign.

[36]Locational marginal prices (LMPs) are prices at a given network node based on the cost of delivering the next MW of energy to that node. For example, if there is a need for 10 MW at a network node, the LMP would be determined by the cost of delivering the 11th MW.



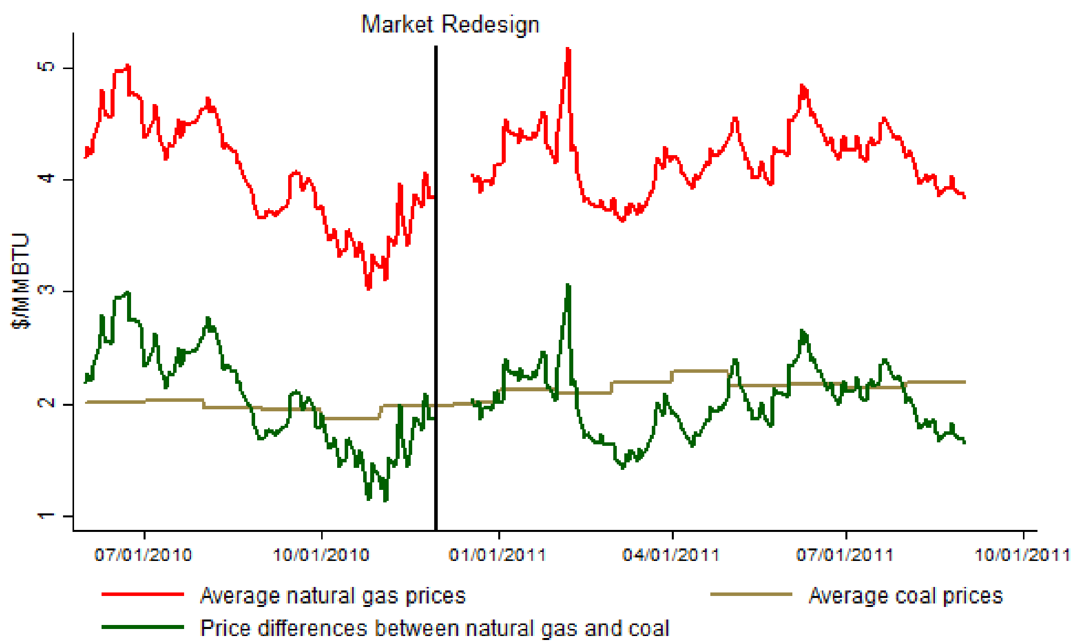
Notes: These figures show the histograms of hourly thermal demands at eight weather zones separately for pre-redesign and post-redesign periods. The pre-redesign period goes from Jun 1st 2010 to Nov 30th 2010. The post-redesign period goes from Dec 1st 2010 to Aug 31th 2011. Demand at each zone is divided into 12 equal-frequency bins based on the entire sample.

Figure A1: Histogram of Hourly Thermal Demand By Weather Zones

A.4.2 Comparison of Fuel Prices

Changes in fuel prices are the only factor that may substantially affect generators' marginal costs. Other factors either do not change over time or constitute a very small portion of the cost. In order to attribute the changes in generation to market redesign, it is essential to look at how fuel prices moved during the sample period.

Figure A2 plots the movement of coal prices and natural gas prices during the sample period[37]. Overall, the magnitudes of the price changes for both natural gas and coal are quite small. On average, coal and natural gas prices during the post-redesign period increased by 19.8 cents (10%) and 12.9 cents (3%) respectively compared to before. The ranges of the price differences are also similar pre and post redesign.



Notes: This figure shows the time series of average coal prices and natural gas prices as well as the price differences during the sample period which goes from Jun 1st 2010 to Aug 31th 2011 excluding Dec 1,2010 to 17 Dec 2010 and Feb 2, 2011 to Feb 5, 2011. The vertical line indicates the time when the market redesign took place.

Figure A2: Average Coal and Natural Gas Prices During the Sample Period

The comparability of the fuel prices is reassuring. Furthermore, I directly include a quadratic form of the price differences between natural gas and coal in the baseline model to

[37] To be consist with the sample I use for estimation, I exclude dates between Dec 1,2010 to 17 Dec 2010, for the lack of ERCOT data, and also dates between Feb 2, 2011 and Feb 5, 2011, for the unusual winter storm.

capture any effect caused by relative changes in fuel prices. This should adequately control for the impacts of fuel prices. Besides that, I believe the findings are not likely to be driven by changes in fuel prices for two additional reasons. First, given that on average the price for coal increases more than the price of natural gas during the post redesign period, this would have made coal generators less appealing than before. Contrary to the direction of the price movement, I find that coal displaces natural gas generation by significant amounts. It is unlikely that the relative changes in fuel prices cause these switches. Second, I perform a similar analysis for only natural gas generators to get rid of the concern for the confounding effect of fuel prices. Within natural gas generators, the order of the marginal costs is basically determined by their heat rates and not affected by the change of natural gas prices. I run similar regressions as equation (1) but use demand for natural gas generation instead of thermal generation as the explanatory variable. The results are quite consistent with the main findings: generation from cheaper resources, such as combined-cycle generators and combustion turbines increases while generation from more costly resources, i.e. steam turbines decreases.

A.4.3 Entry and Exit of Thermal Generators

In the estimation, I restrict the sample to all thermal generating units that were continually operating during the entire sample period. There are 3 thermal units that have either entered or exited the market in this time period. Two steam turbines, each with a capacity of 800 and 115 MW, exited the market prior to the market redesign. One combined-cycle natural gas plant with a capacity of 640 MW entered the market on Mar 16th 2011. The entry and exit of these units pose the question of whether the observed changes in generation are caused by these units. Although it is difficult to separate out their impacts, I contend that this is not likely to be the case. The average hourly generation quantities from these three units while they were operating were only 69.9, 4.71 and 127.9 MWh respectively. Their generations account for less than 0.1% of the total thermal generation. Given the magnitude of their average generations, the results cannot be explained by their entry and exit.

A.4.4 Placebo Tests

Finally, I perform placebo tests to show that the magnitudes of changes I find are indeed unusual and not seen in other years. For this exercise, I pretend there were a redesign happening on December 1st in 2009 and 2011 as well and repeat the analysis for those years.

Plant Name	Entry/Exit	Time	Technology	Capacity (MW)	Average Hourly Generation (MWh)
Tradinghouse	Exit	Sep 19th 2010	Natural gas: steam turbine	800	69.86
Permian Basin	Exit	Nov 21st 2010	Natural gas: steam turbine	115	4.71
Jack County	Entry	Mar 16th 2011	Natural gas: combined cycle	640	127.9

Notes: This table lists the thermal generators that have entered or exited the market during the sample period. Data come from EIA-860 forms. The entry/exit dates are also cross-checked with CEMS data and web sources.

Table A2: List of Generators that Entered or Exited During the Sample Period

I focus on a very short time period – two months centered around the (real or pseudo) implementation date of the market redesign. Given the short time frame, I am confident that there are no significant changes in capacity, cost and other aspects of the market. I run regressions similar to equation (1). But given fewer observations, I simplify the analysis by using the entire thermal demand instead of the demand at each zone and fitting a constant line within each bin. I also estimate the regressions at more aggregate level by fuel and technology types. For type i at hour t, the estimation equation takes the following form:

$$\text{Gen}_{it} = \sum_{k=1}^{12} \beta_{ik} Bin_k(ThermalDemand_t) + \epsilon_{it}$$

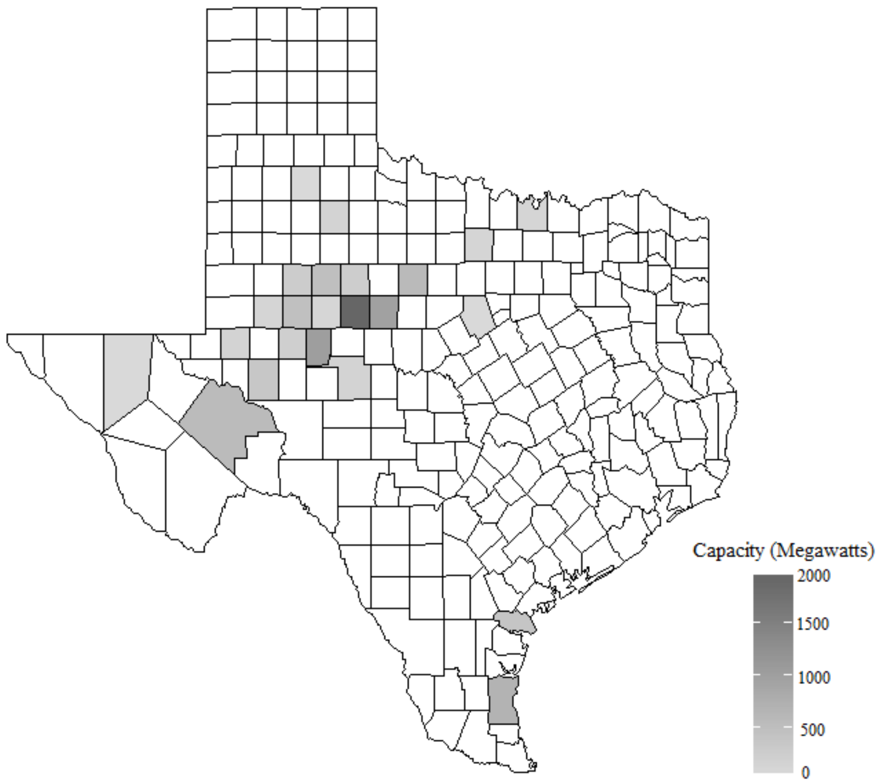
where Bin_k is equal to 1 if the thermal demand falls into that bin. Figure A3 reports the results for the four categories: coal, combined-cycle natural gas, natural gas combustion turbines and steam turbines. It is quite clear that the changes we see in 2010 are not shared by other years. For coal and combined-cycle natural gas, the "before" and "after" generation lines are intertwined and close to each other. Only in 2010 when there is a real redesign do we see significant gaps between these two lines. For combustion and steam turbines, the parameters are estimated less precisely. For steam turbines, there is evidence of a significant effect of market redesign when demand is over 20,000 MWh. Again, we don't see the same effect in other years. For combustion turbines, the changes in 2010 are not very different from changes in 2009 and 2011. Overall, the 95% confidence interval of the two generation lines overlaps for 2010. However, this does not contradict the earlier findings that generation from combustion turbines increases, because the increase occurs only during high demand hours. Figure 7 shows that the effect starts to show up when the thermal demand exceeds 50,000 MWh. Given that the demand in November and December never reaches 50,000 MWh, it's unsurprising that the effect of market redesign on combustion turbines is not salient.

Notes: These figures report the results from the placebo tests as explained in the text.

Figure A3: Results of Placebo Tests

A.5 The Effect of Redesign on Wind Generation

Wind energy has a significant presence in the ERCOT region. As of 2010, installed wind capacity in ERCOT amounts to 9,363 MW, representing 9.45% of the overall generating capacity. As shown in Figure A3, the majority of the wind farms are located in the west of Texas, with the rest in the southern portion of the state.



Notes: This figure is constructed by the author using data from the 2010 EIA-860 forms.

Figure A4: Installed Wind Capacity in ERCOT, 2010

Wind power is determined by the availability of wind resources. Specifically, the level of electrical output a wind turbine can generate is proportional to its cross-sectional area and the cube of the wind speed. Wind is non-dispatchable in the sense that wind speed cannot be changed by will. However, cases do occur in which potential wind generation is not fully used. This happens largely because of the limited transmission capacity between western Texas where the most abundant wind resource is and eastern Texas where most of the demand is. In some cases, wind generation has to be curtailed to avoid overloading the congested transmission lines[38]. Therefore, it's natural to ask if the market redesign results in fewer incidences of such curtailment and better integration of wind resources.

Without data on the frequency of wind curtailments, I rely on a regression approach to examine the effect of market redesign on wind generation. The idea is that wind output is determined mostly by wind speed. If there is no effect, we should expect to see that the observed wind output curve stays more or less the same before and after the redesign. However, if redesign leads to better integration of wind resources, we should see a significant gap for wind outputs given the same wind speed and other market conditions before and after. 350 MW of additional wind capacity was added during the sample period. To rule out this effect, I restrict my sample to a subset of wind farms that were already in operation as of Jun 1st 2010. I conduct the analysis at the weather zone level. For zone i at hour t, I estimate the following regression:

$$GEN_{it} = \theta_i After_t + \sum_{k=1}^{3} \alpha_{ik} WSP_{it}^{(k)} + \sum_{k=1}^{8} \beta_{ik} Demand_{kt} + \delta_h + \epsilon_{it}$$

where GEN_{it} is the aggregated wind generation quantity in zone i at hour t. $After$ is a dummy that indicates if it's post redesign. WSP is the average wind speed raised up to the power of three[39].I also include demands in all eight weather zones and hourly fixed effects. Newey-West standard errors are calculated using 24-hour lags.

Table A3 shows the results of the coefficients for $After$ at the five weather zones which have non-zero installed wind capacity. Although there appear to be some increases in generation when only wind speed is included in the model, the effect goes away as more controls are added. In the full model, there is no evidence of significant increase in generation after the redesign. If anything, the results seem to suggest that wind generation is lower in some of the regions post redesign.

[38]See Sioshansi and Hurlbut (2010) for an extensive discussion of the ERCOT market protocols with respect to wind generation.

[39]Wind speed data are collected from National Centers for Environmental Information(NCEI)'s Integrated Surface Database. One station is selected from each county where wind farms exist and data are available. The average wind speed for each zone is calculated by taking the simple average of the stations within that zone.

Weather Zone	Model (1)	Model (2)	Model (3)
Far West	53.01**	31.30	-19.98
	(24.03)	(23.35)	(26.15)
North	21.54***	18.34***	2.94
	(5.17)	(4.76)	(5.57)
North Central	26.72***	12.42	-26.19**
	(9.95)	(9.18)	(12.10)
Southern	7.68	8.42	-13.56
	(8.98)	(9.05)	(12.03)
West	23.97	-44.42	-129.56***
	(36.28)	(30.45)	(36.04)
Cube of WSP	Y	Y	Y
Hour	N	Y	Y
Demand	N	N	Y

Notes: Newey-West standard errors are reported in the parentheses.
*** Significant at 1% confidence level
** Significant at 5% confidence level

Table A3: The Effect of Redesign on Wind Generation