Pass-through from Fossil Fuel Market Prices to Procurement Costs of the U.S. Power Producers

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August, 2015

Abstract

This paper investigates the transmission of fossil fuel market price changes to procurement costs of U.S. power producers. We measure and compare the speed and magnitude of the pass-through across fossil fuels. We analyze whether the pass-through differs across regulatory status, and whether there is asymmetric price adjustment to positive versus negative market shocks. We document evidence that although the pass-through of natural gas and oil spot prices are fast and relatively complete, the pass-through of coal spot prices is sluggish and far less complete. The empirical results also suggest differences in pass-through patterns across regulatory status and asymmetric price adjustment given positive and negative cost shocks. We show that the differences in pass through across fuel types may have implications for the electricity market deregulation literature that creates marginal cost curves as a competitive benchmark. There are significant differences in marginal cost curves constructed from spot and receipt prices driven by differences in pass through across fuels.

Keywords: electric power industry; fossil fuel market; pass-through; deregulation; asymmetric price adjustment

JEL Codes: D40, L51, L94

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1 Introduction

For a variety of reasons including exposure to risk, incidence and methodological issues cost pass-through receives broad attention in economics.[1] In the energy sector, pass through receives particularly intense attention as both a transportation fuel ((Knittel et al., 2015)) and in the electric power industry (Zachmann and Von Hirschhausen (2008), Fell (2010), Fell et al. (2013), and Fabra and Reguant (2014)). The energy sector is particularly important because both households and firms budget for energy expenditures, which account for roughly 5% of GDP[2] Electricity input price pass through is a particularly important question because electricity producers have been shown to exhibit market power manifested through markups over marginal costs thereby leading to welfare decreases (Borenstein et al. (2002)).

In this paper, we evaluate how fossil fuel procurement costs for U.S. electricity producers respond to fluctuations in commodity spot market prices and whether those responses vary by fossil fuel type. We pay special attention to how quickly spot market price changes manifest in procurement costs and whether pass through is complete. We measure the pass-through for three types of fossil fuels: coal, natural gas and petroleum. The drop in natural gas prices due to hydraulic fracturing makes this an important policy question: as more electricity is produced from natural gas, changes in the timing and completeness of pass through could affect volatility of electricity prices and in turn the wider economy. We are not aware of any previous studies devoted to this issue.

To address the question we collected fuel procurement data from the Energy Information Administration (EIA) under a special agreement which gave us access to fuel procurement data for almost all fossil fuel power plants, both regulated and unregulated, in the United States for each shipment over a 9 year period from 2002-2010. We then matched each power plant to fossil fuel spot market price data from Bloomberg Data Services. Consistent with the pass through literature, we then estimate auto-regressive models with different lag structures and fixed effects to identify how quickly pass through occurs for different fossil fuel types in the United States.

[1] In international economics, there are a series of studies that investigate the transmission of exchange rate fluctuations to prices of imported goods (among others, see Goldberg and Knetter, 1997). The analysis of cost pass-through also provides important implications on the issue of tax incidence in public economics (Marion and Muehlegger, 2011) and price discrimination (Aguirre et al., 2010), merger assessment (Weyl and Fabinger, 2013), the incidence of anticompetitive firm behavior (Verboven and van Dijk, 2009) and (Kim and Cotterill, 2008) in industrial organization.

[2] See `http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0105`.

Our main finding is that natural gas spot price pass through is very fast and complete whereas coal spot price pass through is very slow and incomplete. Natural gas spot price fluctuations are passed on to fuel purchases almost completely within two months. Conversely, we find that coal price fluctuations are only partially passed through. A 1% change in natural gas spot price leads to an approximately 0.85% change in the contract prices received by the power plants within 1 month. However, a 1% change in coal spot price leads to an approximately 0.11% change in the contract prices received by power plants even after 12 months.

The results are consistent with conventional wisdom that coal is purchased via long term contracts. Conversely, natural gas is purchased via the spot market since it is delivered by pipeline directly to powerplants. Other channels of pass-through incompleteness identified in the literature relevant for our paper do exist though. For example, there could be a mismatch between observed cost shocks and a firm's actual opportunity costs (Nakamura and Zerom, 2010; Fabra and Reguant, 2014). However, we are not able to identify the underlying cause of pass through asymmetry using our research design.

We also examine how the pass-through pattern varies under different regulatory and market circumstances. First, we compare the pattern between traditional regulated power plants and divested Independent Power Producers (IPPs). Previous literature on deregulation in the electric power industry documents evidence that divested power plants operated more efficiently under competition pressure. Specifically, deregulated coal-fired plants reduce procurement costs for coal relative to regulated plants (Chan et al., 2013; Cicala, 2015; Jha, 2015). A related questions is whether the pass through of fossil fuel prices differs between plants of different regulatory status. For natural gas purchases, we find evidence that the transmission of spot prices to power producers' procurement costs is significantly faster in deregulated power plants than regulated power plants. In contrast, we don't find any significant differences in the pass-through pattern across regulatory status for coal purchases. We note, though, that due to lack of any variation in regulatory status during our sample period our findings are not causal.

Finally, we analyze whether pass-through varies given an increase in market price versus a decrease. Asymmetric price adjustment has been empirically documented in a number of commodity markets (Peltzman, 2000), particularly in the fuel market (Borenstein et al., 1997).[3] We find that natural gas price decreases pass through more quickly than price increases shocks. We don't find any evidence of asymmetric pass-through for coal or oil purchases.

Our results are relevant to both economists and policy makers. First, an increasing share of natural gas in the fuel mix for electricity generation due to lower prices attributable to hydraulic fracturing. Rapid and complete price pass through implies that any market volatility in natural gas prices will pass through to electricity producers quickly. It could become increasingly difficult for both power producers to hedge against the market risk of input procurement costs. If those input prices are subsequently passed on to electricity purchasers in the wholesale market retail electricity prices could become more volatile. Slow pass through of coal commodity prices mitigated this problem historically.

Second, we document evidence that there are distinct pass-through patterns from fossil fuel spot prices to procurement costs by regulatory status. Pass through is faster for deregulated power plants for natural gas purchases. This is consistent with previous findings that deregulation affects the fossil fuel purchase behaviors of power plants (Chan et al., 2013; Cicala, 2015; Jha, 2015). However, our findings are not sufficient to make causal inference since we do not observe cross-sectional variation in regulatory status. It does, though, provide further evidence that deregulated firms operate very differently than regulated firms. A more complete theoretical model of pass through would be needed to determine the welfare effects of these differences.

Third, the adjustment lag between fossil fuel spot prices and procurement receipt prices for power plants also has methodological value. We construct counterfactual electricity market marginal cost curves (known as dispatch curves) for two widely-studied markets, California (CAISO) and Pennsylvania, Jersey and Maryland (PJM). We create two marginal cost curves for each market each month of each year of our sample: one based on spot fuel prices and the other based on receipt fuel prices. Our finding suggest that for coal fired power plants commodity spot prices are not a good measure of fuel procurement costs when measured at the month level. This finding has implications on constructing counterfactual competitive supply curves commonly used in the

[3] For analyses in the electricity market, Zachmann and Von Hirschhausen (2008) first raised the puzzle of an asymmetric pass-through from European Union's CO_2 emission prices to wholesale electricity prices. Mokinski and Wölfing (2014) document empirical evidence of asymmetric adjustment of wholesale electricity prices in response to CO_2 emission prices.

static approach of measuring market power in the electricity market.[4] Much of the literature use respective fossil fuel spot prices to calculate the marginal costs of generating units and build counterfactual competitive supply curves. Our results imply that while this might be appropriate for natural-gas-fired units, it might not be the case for coal-fired units.[5]

There are a couple a caveats to our study. First, we test for differences in commodity market pass through to fossil fuel procurement of electricity producers. The more important question from a welfare perspective is how fossil fuel prices are pass through to electricity prices. Data limitations and strategic firm behavior restrict our ability to address the electricity pricing question. Second, we estimate differences in pass through by regulatory status rather than the causal impact of deregulation on pass through. As a result, our regulatory results are merely suggestive. Similarly, we don't have an instrument to identify the causal impact of commodity price increases or decreases on fuel procurement costs. The goal of our paper is simply to document differences in pass through behavior between coal, oil and natural gas power producers.

The paper proceeds as follows. Section 2 describes the context of the analysis. Section 3 describes the data and summary statistics. In Section 4, we present the baseline empirical model. In Section 5, we provide the empirical results and the discussion. In Section 6, we discuss the methodological implications of the empirical results on a least cost dispatch model commonly used in the studies on the electricity sector. Section 7 concludes.

2 Context

2.1 Contract Duration of Different Fossil Fuels

The duration of fossil fuel contracts between the power producers and suppliers is a key factor affecting fuel substitution in the generation mix in the electric power sector given spot price shocks (OECD/IEA, 2013). There are significant differences in contract duration between the coal and natural gas markets in the U.S. Coal market is characterized by long contracts: the median con-

[4]See Borenstein and Bushnell (1999) and Borenstein et al. (2002) for the electricity market in California, Wolfram (1999) for the electricity market in UK, and Mansur (2007) for the Pennsylvania, New-Jersey, Maryland (PJM) electricity market.

[5]This literature focuses on electricity market deregulations that occurred before our fuel receipt price data begins. Unfortunately, we cannot directly test the implications of using spot versus receipt prices on estimating the efficiency loss/gain from electricity market deregulation using these two different types of fuel costs.

tract averages around 2 years in 2014 (Matisoff et al., 2014); 93% of coal consumed for electricity generation in the U.S. was purchased via long-term contracts of more than a year (rather than spot contracts) in 2011 (EIA, 2012). In contrast, the standard contract in the natural gas market is much shorter. In 2011, 66% of natural gas consumed for electricity generation in the U.S. was purchased via spot contract (EIA, 2012). Shorter natural gas contract lengths are potentially due to its wider use across different sectors although several other explanations like extant natural gas pipeline infrastructure are feasible (Petrash, 2006). As for contract terms between power producers and oil suppliers, Matisoff et al. (2014) argue that spot prices are more relevant.

2.2 Difficulty of Measuring the Pass-through to Wholesale Electricity Prices

Most previous literature of cost pass-through in the electricity market focuses on the transmission of input price shocks (e.g., emission allowance price variations) to wholesale electricity prices. Although we have detailed plant-level data, we lack some key variables to measure how shocks in fossil fuel receipt prices lead to changes in wholesale electricity prices.

There are a couple reasons for focusing on fuel procurement costs rather than wholesale electricity prices. First, for traditional regulated electricity markets, wholesale electricity transactions are realized via bilateral trading where market price determination mechanism is opaque. Also it is unclear what regulators use as marginal cost estimates for wholesale transactions between regulated utilities. Second, for restructured markets, the wholesale price is determined by bidding in multi-unit auctions. Measuring bidding behavior response by the marginal generating unit to changes in its marginal costs (e.g., fluctuations of fossil fuel procurement costs) is challenging because a firm's optimal bidding behavior depends not only on fossil fuel price shocks, but also the strategic adjustment of markups (Wolfram (1998); Borenstein et al. (2002); Hortacsu and Puller (2008); and Fabra and Reguant (2014)).

Finally, in the case of deregulated power plants, in order to cleanly identify the pass-through from fossil fuel price changes to wholesale electricity prices, economists must tease out the the contribution of strategic adjustment of markups and separate it from fuel costs. The previous literature derives the markup of a utility firm from the first-order condition of profit maximization, which depends on the net quantity sold (i.e., its production minus its vertical commitment), and the slope of the residual demand faced by the firm. The general approach of the previous literature is calculating the former by subtracting the firm's output by purchases from its subsidiaries, and approximating the latter based on the bid data. We don't have access to datasets on bidding behavior nor do they exist for regulated markets.

For all of these reasons, we focus on the pass-through between fossil fuel market prices and procurement costs of power plants. Using this metric gives us a direct measure of pass through mitigating any strategic factors in deregulated markets or any missing variables issues in regulated markets. It allows us to answer our primary question of interest in this paper: how does speed and completeness of pass through vary by fossil fuel type and regulatory status.

3 Data

3.1 Data Description

The study mainly exploits three separate data sets: (1) market spot prices of fossil fuels; (2) plant-level fossil fuel receipt cost data for electricity producers; and (3) cost estimates of railway transportation.

The first data set is mainly collected from Bloomberg. From the Bloomberg data, we obtain daily spot and future prices for natural gas at several hubs and coal extracted in three major deposits in the U.S.: the Powder River Basin, the Illinois Basin and the Central Appalachian (PRB, Illinois and CAPP). From EIA we collected weekly West Texas Intermediate spot prices, which is the benchmark price for the U.S. oil market. We aggregate the daily and weekly market prices to monthly averages to be consistent with frequency of the fossil fuel receipt cost data.

The main source of the second data set is the records of FERC-423 and EIA-423 data forms called the "Monthly Report of Cost and Quality of Fuels of Electric Power Plants". FERC-423 form must be filed by all utility electricity-generating plants with a capacity of at least 50 megawatts, while EIA-423 is designated for the non-utility counterparts with capacity above the same cutoff. After 2008, both forms were incorporated in survey Form EIA-923. The non-utility part of the data is not publicly available for privacy protection purpose. We requested the proprietary data from EIA by signing a non-disclosure agreement which permits us to use the data for this high level

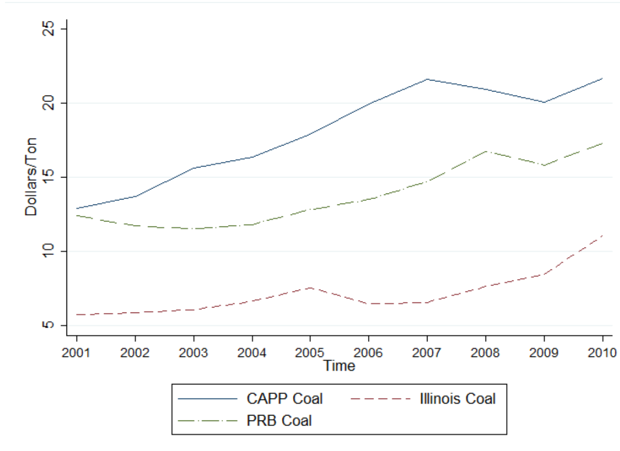


Figure 1: Rail Transportation Costs for Coal, by Mining Basins

Note: 2001-2007 data is based on the Surface Transportation Board (STB)'s 900-Byte Carload Waybill Sample. 2008-2010 data is calculated by EIA, which augmented STB's Waybill sample by EIA-923 Power Plant Operations Report data.

analysis.

The transaction-level data contains purchased fossil fuel types with details to sub-fuel categories (e.g., bituminous coal), contract prices (including transportation costs and taxes), quantity of fuel delivered, average heat content of the fossil fuel, contract terms (e.g., contract type and expiration date), average sulfur and ash content of coal, location of the purchasing plant and the origin of all coal shipments.[6] Coal origin allows us categorize the coal transactions by coal type and thus match each procurement contract with the associated coal market price (PRB, CAPP or Illinois) from Bloomberg. We match natural gas purchases to the nearest trading hubs based on major transportation flow pattern of the U.S. Natural Gas market.[7] We match spot prices at Waha Hub (TX) for plants in NE and KS, prices at Opal Hub (WY) for plants in UT, WY and CO, prices at Blanco Hub (NM) for plants in AZ and NM, prices at Chicago Hub for plants in WI and IL, and prices at AECO Hub (Canada) for plants in IA, MN, ND, MT, WA, OR and NV, and prices at Henry Hub (LA) for the remaining plants.

Our third dataset controls for the costs of shipping coal via rail. Our fuel procurement cost data includes transportation delivery costs for coal. According to EIA reports, railroad is the main

[6]The contract types are divided into "spot market" deliveries (for contracts that expire in less than one year), and "contract" delivery (for longer-duration contracts). Expiration dates are available for those that would expire in the next 24 months.

[7]See the map available from EIA: `http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MarketCenterHubsMap.html`.

transportation mode for coal delivered to electric power plants (over 70% in 2010). Moreover, rail transportation costs account for a sizable share of total delivered costs of coals for electric power producers and vary across shipments of coal originating from different coal basins.[8] Unobserved changes in rail transportation rates would bias the estimated results on the pass-through from coal market prices if correlated with changes in coal prices.

The EIA estimates that the costs of transporting coal to power plants rose by 46% nationally from \$ 11.83 to \$17.25 per ton from 2001-2010. Figure 1 shows the estimated rail transportation costs for coal originating from three major coal deposit basins we analyze in this paper. There are substantial increases in the rail delivery costs for coals from all 3 basins. During the same time, the demand for PRB coal increased due to environmental regulation and the lower sulfur content of PRB coal.

We are not aware of any dataset which specifically reports coal transportation costs so in order to handle this issue, we combine two data sets to approximate the changes in railroad transportation costs. The first data set is the EIA-estimated rail transportation cost data (\$/ton), which is available on yearly basis, and provides detailed information about deliveries from each coal basin to each state destination. For some deliveries, the data is proprietary to protect trade secrets. For those deliveries we use the average costs of deliveries from the same basin for proxies.

The second data set is the Rail Cost Adjustment Factor (RCAF) used in Busse and Keohane (2007). The RCAF is a national cost index computed quarterly by the Association of American Railroads to measure the rate of inflation in railroad inputs such as labor and fuel. It is also adjusted for productivity gains. The cost index is used by Surface Transportation Board to assess railroad rates. We transform the yearly data from EIA to quarterly data based on the quarterly deviation of Rail Cost Adjustment Factor as the share of the yearly average. Specifically, we applying the following formula to our data:

$$Rail\ Cost_{y,q} = Rail\ Cost_y + \frac{RCAF_{y,q} - \frac{1}{4}\sum_{q=1}^{4} RCAF_{y,q}}{\frac{1}{4}\sum_{q=1}^{4} RCAF_{y,q}} * Rail\ Cost_y, \tag{1}$$

[8]EIA reports that during 2001-2008, the national average share of rail transportation cost as percent of total coal delivered costs is 20%. The number could reach as high as 59% for shipments of coal originating in Powder River Basin. See more details on EIA reports available at http://www.eia.gov/coal/transportationrates/archive/2010/trend-coal.cfm.

where y is a specific year, q is a quarter of year, $RCAF$ is the Rail Cost Adjustment Factor. We then assume within the same quarter, the rail transportation costs for coal deliveries to power plants grow at a constant rate. This interpolated proxy gives us the ability to calculate a monthly time series for rail delivery costs for coal.

Finally, we exploit the North American Industry Classification System Code (NAICS) information available from the records of the EIA-906 data form (also incorporated in EIA-923 after 2008),"Annual Electric Utility Data", to restrict the sample to electricity-generating plants in the electric power industry only. We further take advantage of the EIA Sector Code to identify plants that are divested non-utility Independent Power Producers (IPPs) and those that are regulated electric utility producers.

Table 1: Summary Statistics

	Unit	**Mean**	**Std. Dev.**	**Min.**	**Max.**	**Obs.**
Receipt Prices for Power Plants						
PRB Coal	Cents/MMBtu	141.9	52.3	12	957.5	46041
CAPP Coal	Cents/MMBtu	235.6	97.0	5.9	1022.9	74178
IL Coal	Cents/MMBtu	179.9	74.3	31.8	640.0	16161
NG	Cents/MMBtu	643.6	254.3	1.6	1785.8	138269
Oil	Cents/MMBtu	1287.9	554.2	1	2978.2	27968
Spot Market Prices						
PRB Coal	Cents/MMBtu	55.4	19.5	30.6	117.9	108
CAPP Coal	Cents/MMBtu	222.7	80.9	111.6	511.3	108
IL Coal	Cents/MMBtu	165.7	53.4	103.2	348.2	108
NG (Henry Hub)	Cents/MMBtu	605.4	227.465	225.7	1342.3	108
Oil (WTI)	Cents/MMBtu	1023.2	436.2	339.9	2308.3	108
Rail Transportation Cost	Dollars/Ton	14.0	5.0	2.4	37.4	8328

Note: The summary table is based on data from 2002 to 2010. For some natural gas and oil and purchases with trivial volumes, the receipt prices is overly high. We drop receipt prices of natural and gas above the 99th percentile.

3.2 Summary Statistics

Table 1 shows summary statistics for our data. There are non-trivial differences between the averages of spot market prices and the receipt procurement costs paid by power producers. The mean spot market prices are lower than costs for every fuel type. Highlighting the importance of transportation costs, though, the relative price differences are largest for coal (relative to natural gas and oil). Among the three types of coal, the mean spot market price of the PRB coal accounts for roughly 40% of the delivery price. This is consistent with relative clean PRB coal being shipped to east coast power plants subject to stricter environmental regulation on air pollution emissions.

To get a sense of dynamics in the data, Figure 2 plots changes in fossil fuel prices over time. Panel (a) displays fluctuations in fossil fuel spot market prices across time. The Panel shows that the spot market price of PRB coal was less volatile than other fuel types. Given that market prices are jointly determined by supply, demand and substitutes, we are agnostic about the causes of this difference. We do note that all prices appear to be positively correlated to some extent.

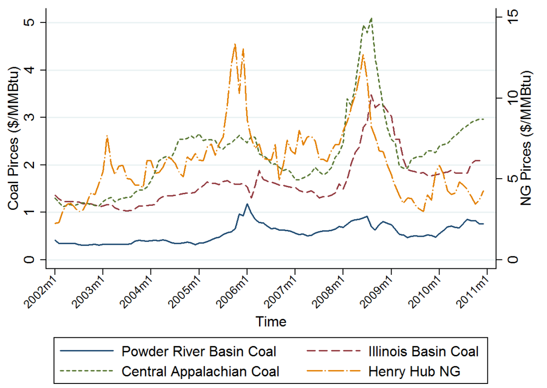
Panels (b) and (c) highlight how procurement costs for coal fired power plants in two different parts of the country changed over our sample period. Transactions made by power plants near the relevant coal mining basins are selected to be compared with the spot market prices. We choose two states, Colorado and West Virginia, to highlight how receipt prices for PRB and CAPP coal, evolved over the sample period.[9] Panel (b) shows average procurement costs of PRB coal for coal plants in Colorado and panel (c) shows procurement costs of CAPP coal for coal plants in West Virginia. For both locations coal procurement costs display a consistent upward trend. For CAPP coal, procurement costs lack the the high frequency volatility in the commodity spot market prices. For PRB coal, procurement costs increase despite relatively flat spot market PRB coal prices. Panel (d) shows average procurement costs for natural gas delivered to New York power plants. These prices appear to track the level and volatility of NG spot prices at Henry Hub. Despite not controlling for rail transport prices for coal, the graphs appear consistent with rapid natural gas pass through and slow coal price pass through.

4 Empirical Strategy

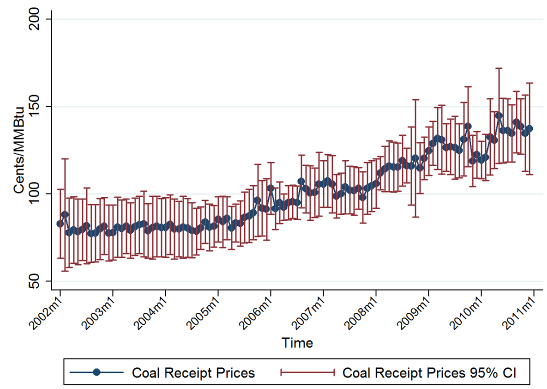
This study focuses on measuring the pass-through of commodity spot market prices to fuel procurement costs in the electricity sector. To do so we use a reduced form econometric approach. We do not claim to identify causal impacts nor identify the underlying mechanisms behind our findings.

In order to understand how changes in fossil fuel spot prices are transmitted to power producer

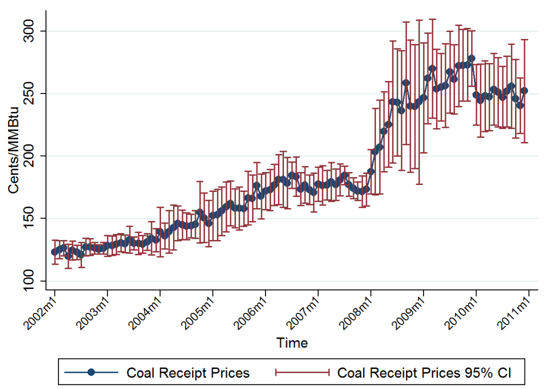
[9]Based on EIA's fuel purchase data for power plants, PRB coal made up 54% of total consumption in Colorado, and CAPP coal made up 23% of total coal consumption in West Virginia during the sample period.



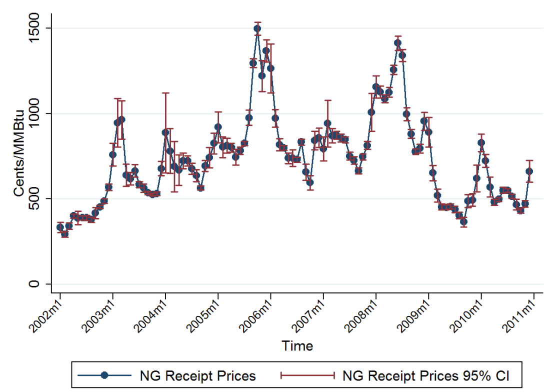
(a) Fossil Fuel Spot Market Prices



(b) Average Coal Delivered Receipt Costs in Colorado



(c) Average Coal Delivered Receipt Costs in West Virginia



(d) Average NG Delivered Receipt Costs in New York State

Figure 2: Fossil Fuel Spot Market Prices and Delivered Receipt Costs for Power Plants

Note: the average fossil fuel delivered costs for power plants is weighted by transaction volume. PRB Coal purchases for plants in Colorado are selected to represent those for the PRB coal. CAPP Coal purchases for plants in West Virginia are selected to represent those for the CAPP coal. Fossil fuel receipt prices for power plants also include delivery costs. Panels b-d report the coefficients and 95% confidence intervals from a regression of fossil fuel prices on month of sample dummies. They recover the average cost and a measure of the variance of the cost across plants in the state that use that fuel.

procurement prices, we apply a common empirical model in the pass-through literature on exchange rate in international economics.[10] Those models are intended to determine how quickly exchange rate fluctuations are passed through to market prices of traded goods. That approach is well-suited to handle our setting if each individual power producing company cannot influence the market commodity price of each type of fossil fuel individually. It does allow, though, for demand across power producing firms to be correlated.

Our econometric specification takes the following form:

$$\Delta log(Fuel\ Price_{it}^{f}) = \alpha + \sum_{k=1}^{12} \beta_k^f \cdot \Delta log(Spot\ Price_{t-k}^{f}) \cdot 1[Fuel_f] + \Psi \cdot X + \epsilon_{it}^{f}. \tag{2}$$

In equation (2), t represents unique time periods, i indexes a power plant, f is a specific type of fossil fuel (coal, natural gas or oil) and $1[Fuel_f]$ is an indicator variable for each fuel. The term Δ represents first difference transformations, $log(FuelPrice_{it}^{f})$ is the log of mean delivered cost of fuel for plant i in month t, $log(SpotPrice_{t-k}^{f})$ is the log spot market price for fuel f lagged $k = 1, ..., 12$ months. X is a vector of control variables. We add lagged fossil fuel spot prices to allow for the possibility of gradual adjustment of power plants' procurement costs to spot prices, especially given the contract duration terms discussed in Section 2.1. β_k^f is the coefficient of interest, which measures the percentage change in receipt prices of fuel f associated with a one percentage change in the corresponding spot market prices k months ago. The cumulative sum of the coefficients, $\sum_{k=0}^{12} \beta_k$, is then defined to be the aggregate long-run pass-through rate. The coefficients are identified off variation in changes of spot prices within a power plant owning firm differencing out the average effect for each month.

Our price variables are highly persistent: Dickey-Fuller tests for the hypothesis of a unit root in fossil fuel spot prices cannot be rejected at a 5% significance level.[11] Estimating the model is levels is problematic as a result. Therefore we follow Campa and Goldberg (2005), Nakamura and Zerom (2010) and Goldberg and Campa (2010), by taking the first difference of both the right and

[10] See Campa and Goldberg (2005), Nakamura and Zerom (2010) and Goldberg and Campa (2010) for examples.

[11] We were unable to reject the hypothesis that the series of coal prices at the 3 mining basins, natural gas prices at various hubs, and WTI oil prices were nonstationary. The Dickey-Fuller unit root test on the spot prices in an econometric specification with a time trend rejects the unit root hypothesis only in natural gas prices at Chicago Hub.

left hand side price variables.

In addition to fossil fuel spot prices, we also control for other variables in X, including month-of-year fixed effects, change in log rail transportation costs,[12] and owner firm fixed effects. We estimate the model using the data described in Section 3, for monthly changes in procurement costs and spot market prices over the 2002 - 2010 sample period.[13] The standard errors are clustered at the plant level to allow for arbitrary serial correlation.[14]

In line with previous studies in the exchange rate pass-through literature where firms take the exchange rates as given when pricing the imported goods, the necessary assumption required in the current specification is that power plants are price takers in the fossil fuel spot markets. We argue that this is a valid assumption given the fact that the fossil fuel spot markets are all large with many participates from diverse sectors such that no single power plant (or a power plant owning firm) has the market power to manipulate the spot prices. Although individual plants or firms can engage in bilateral contracting with the fuel suppliers instead of (or in addition to) purchasing via spot markets, we argue this would not grant them the power to manipulate the spot market prices since input sellers always have the opportunity to sell at spot or futures prices. This type of empirical model has also been applied in previous studies with detailed panel data similar to ours.[15]

5 Empirical Results

5.1 Main Results

This section describes the results from estimating equation (2) for coal, natural gas and oil. Since the pass-through patterns of natural gas and oil are very similar, and oil accounts for only a small share of electricity generation, we mainly focus on the pass-through coefficients for coal and natural

[12]Log rail transportation costs are set to zero for natural gas and oil, and for coal plants that are not matched with the estimated rail cost data from EIA (meaning the delivery is via transportation mode other than railroads, such as barge or truck.).

[13]The data sample ends at 2010 because the EIA estimates of coal rail transportation costs are only available till 2010.

[14]We were not able to reject the null hypothesis of no first order autocorrelation under the Wooldridge test for autocorrelation in panel data (Wooldridge, 2010).

[15]The model has been applied in different data structures, such as time series (Campa and Goldberg, 2005) and panel data sets for both aggregate country- or industry-level studies and detailed producer- or product-level studies (Goldberg and Campa, 2010; Nakamura and Zerom, 2010).

gas. More detailed results for oil are available upon request.

Rather than display our results with a table of 12 coefficients, we display our results graphically in Figure 3. Each fuel-specific line connects a month specific point estimate and bars represent the 95% confidence interval for that month's point estimate. The pass-through pattern of coal is distinct from natural gas. Spot market price changes for natural gas quickly pass through to delivered contract costs for natural gas fired power plants. The pass-through responses occur almost entirely in the month of the price change and the subsequent month. The sum of the point estimates for the first two periods is approximately 0.85 with a standard error calculated using the delta method of 0.01. The interpretation of this result is that a 1% increase in natural gas spot market price leads to an expected increase of 0.85% in procurement costs of natural gas by electricity producers within 2 months. Oil price pass through exhibits a qualitatively and quantitatively similar structure.

In contrast, pass-through is much more sluggish and far less complete for coal transactions. For coal, after 12 months the sum of all monthly coefficients is only 0.11 with a standard error of 0.01. This implies a 1% increase in coal spot market price leads to only a 0.11% increase in the contract prices paid by power plants even after an entire year. Since average coal contracts in the U.S. last for approximately 2 years, we also check the empirical model in equation (2) with 24 lags for coal. However, the long-run the pass-through after 24 months only increases to 0.27 (with a standard error of 0.03).[16]

The findings in this section are in one way unsurprising and another way surprising. They are unsurprising in that natural gas prices pass through to electricity generators more quickly than coal prices: coal is procured via longer terms contracts than natural gas. However, the magnitudes are somewhat surprising.[17] Natural gas price pass through is almost complete within two months. Conversely, coal pass through over a year is very small. It suggests that as more electricity is produced using natural gas the electricity prices could become more sensitive to short run changes in fuel price. However, a more complete structural model accounting for strategic considerations

[16]Given the wedge between the spot prices and the power plants' receipt prices for coal (shown in Table 1), we also check level specifications for empirical model (2). Under the level specifications, the long-run pass-through after 12 and 24 lags is 0.19 (s.e.=0.03) and 0.48 (s.e.=0.05) respectively, meaning a 1 cent increase in coal spot prices leads to a 0.19 cent and a 0.48 cent increase in power plants' procurement receipt prices after 12 and 24 months respectively.

[17]In the appendix we show that these results for coal pass through are consistent across each of the three coal basins. We take this as evidence that the pass through estimates are not hiding the effects of unobservable coal characteristics.

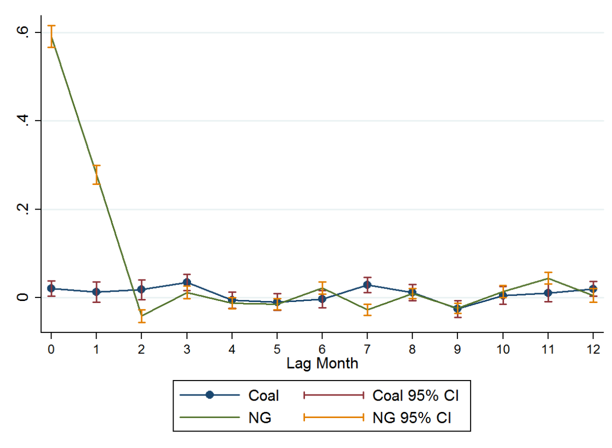


Figure 3: Pass-through Coefficients for Coal and Natural Gas

Note: Lines indicate the point estimates for coefficients associated with each month's lagged commodity spot market price. Whiskers represent 95% confidence intervals.

of electricity producers is needed in order to determine how procured fuel prices are passed on to wholesale electricity prices.

5.2 Variations by Regulatory Status

One attractive feature of our data is that we observe regulation status of each power plant in our sample. We investigate the pass-through pattern between regulated power plants and divested or deregulated plants in this subsection. There is evidence that deregulation affects firms' fuel procurement practices (Chan et al., 2013; Cicala, 2015; Jha, 2015). We are not aware of any study which attempts to determine if pass through varies with regulatory status.

We estimate the following variant of equation (2) to determine differences in pass through by regulatory status:

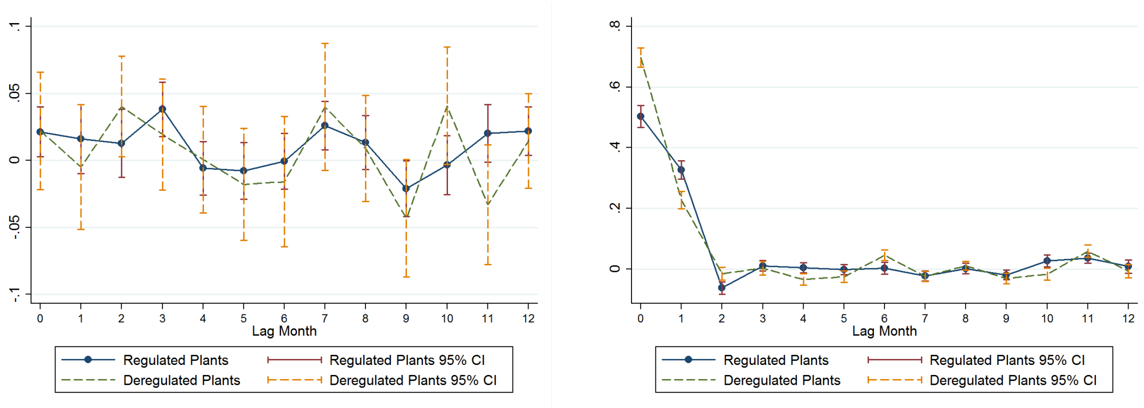
$$\begin{aligned}\Delta log(Fuel\ Price_{it}^{f}) =& \alpha + \sum_{k=1}^{12} \gamma_k^f \cdot \Delta log(Spot\ Price_{t-k}^{f}) \cdot 1[Deregulation_i] \cdot 1[Fuel_f] \\ &+ \sum_{k=1}^{12} \beta_k^f \cdot \Delta log(Spot\ Price_{t-k}^{f}) \cdot 1[Fuel_f] + \Psi \cdot X + \epsilon_{it}^{f},\end{aligned} \tag{3}$$

where $1[Deregulation]$ is an indicator variable taking value of 1 if a plant is a divested independent power producer. β^f now measures the pass-through elasticity of the regulated plants for fossil fuel f, γ_f measures the deviation of pass-through elasticity of the deregulated plants relative to the regulated counterparts for fuel f. Since many oil power plants are clustered in the northeastern U.S. and the vast majority were divested Independent Power Producers, we lack an adequate sample of regulated plants to compare to the IPP's. Accordingly, we focus on coal and natural gas. As before, the coefficients are identified off variation in changes of spot prices within a fuel type, month of year, and a deregulated (or regulated) power plant owning firm.

Figure 4 plots the the aggregated mean pass-through coefficients along with 95% confidence intervals for coal and natural gas purchases by regulatory status. The Figure shows that while coal pass through does not vary with regulatory status natural pass pass through is significantly more rapid in deregulated plants. In the Appendix we also show coefficient estimates numerically to emphasize these statistically significant differences. Specifically, natural gas has higher pass through after one month (.71 versus .5) and two months (.93 versus .86) in deregulated versus regulated power plants. This indicates that given a 1% increase in the spot prices, on average the increase of natural gas procurement prices in deregulated plants is larger by 0.21% than that in regulated plants within one month. The appendix also provides evidence that these results hold across each of the coal basins independently.

For coal, on the other hand, there are no distinguishable pattern of pass-through between regulated and deregulated power plants. For deregulated plants, the receipt price of coal only responds to market price changes after 2 months. For regulated plants, the pass-through from the spot market price of coal to the receipt price could take up to 12 months, and the current receipt price responds to market price changes in current, lag 3, 7 and 12 month.

Given that we observe more rapid pass through of natural gas commodity prices in deregulated plants, it is tempting to conclude that quicker pass through for natural gas led to higher profitability over our study period since deregulated plants are the residual claimant of their own profits. There are several caveats, though. First, we don't estimate causal impacts so we don't claim that deregulation causes quicker pass through. These differences are identified off cross-sectional variation in deregulation which has been shown to be non-random. Second, it could be that quicker pass through led more profitability only due to the dynamics of natural gas prices over our sample period only. Generalizing these results out of sample is therefore not valid. As a result, we urge



(a) Coal Transactions (b) NG Transactions

Figure 4: Pass-through Elasticity: Regulated vs. Deregulated

Note: deregulated plants are defined as divested ones of the independent power producers.

caution in interpreting the mechanism behind this finding.

5.3 Asymmetric Pass-through

The stark difference between pass through of coal and natural gas commodity prices is possibly explained by different hedging strategies. For example, the on-site storage costs of coal versus natural gas are likely to be different. The average coal generators keeps around 60 days worth of fuel in inventory on site (EIA (2014)) while most natural gas units have little or no on-site storage. As a result, there could be differences in how coal versus natural gas generators hedge against input price increases versus decreases. We therefore estimate the model allowing for pass through to vary by fuel price increases versus decreases:[18]

$$\begin{aligned}\Delta log(Fuel\ Price^f_{it}) =& \alpha + \sum_{k=1}^{12} \delta^f_k \cdot \Delta log(Spot\ Price^f_{t-k}) \cdot 1[Negative^f_{t-k}] \cdot 1[Fuel_f] \\ &+ \sum_{k=1}^{12} \beta^f_k \cdot \Delta log(Spot\ Price^f_{t-k}) \cdot 1[Fuel_f] + \Psi \cdot X + \epsilon^f_{it},\end{aligned} \tag{4}$$

where $1[Negative]$ is an indicator variable taking the value of one if the commodity spot price of fuel f decreased k months ago. β^f now measures the pass-through coefficient given a market

[18]Kilian and Vigfusson (2009) shows that estimating these equations replacing decreases in price with zeros lead to censored regressions that are biased towards finding asymmetric pass-through. The authors suggest a similar estimation strategy to the one we employ here.

price increase for fossil fuel f. δ_f instead measures the difference of the pass-through coefficient given a market price decrease relative to an increase for fuel f.[19] The coefficients are identified off variation in increases (or decreases) of spot prices within a fuel type, month of year, and a power plant owning firm.

Figure 5 plots the the mean pass-through coefficients for positive versus negative commodity market price changes along with 95% confidence intervals for coal, natural gas and oil. For coal, there is no obvious asymmetric pass-through pattern in response to positive or negative spot market shocks. The responses under spot price increases and decreases at different lags are not statistically different from each other except for the month 11 lags which we attribute to noise.

For natural gas purchases, power producers' procurement prices respond quickly (within 1 month) to both negative and positive spot market shocks. Yet, a 1-month lag negative shock passes on to the procurement costs more than a 1-month lag positive price changes (by 0.08% given a 1% change in spot price in absolute value). Positive shocks are significantly more likely to be passed through after three months, possibly after natural gas market hedging options have been exploited. Both results are consistent with natural gas plants being somewhat strategic in their procurement behavior since decreases are passed through more quickly and increases are passed through more slowly

Oil price pass through is similar to natural gas pass through although the estimates are less precisely estimated, due largely to the much smaller sample size. There is weak evidence (10% significance level) that the pass-through is different given a positive and negative shock within the first month. Pass through of positive shocks is larger than pass through of negative shocks between the first and second months. Focusing on the net effect of the first two months when majority of the pass-through responses occur, however, a Wald test cannot reject (at 5% significance level) the null hypothesis that the sum of the pass-through responses under a positive shock is statistically different from the sum under a negative shock.

In sum, we find that coal continues to exhibit no strong difference in pass through for increases versus decreases. Conversely, for both natural gas and oil plants, we do find some weak evidence of pass through asymmetries by the direction of spot market price changes. While this is possibly

[19] Table 3 in the Appendix shows β_k^f and δ_k^f for up to 6 month.

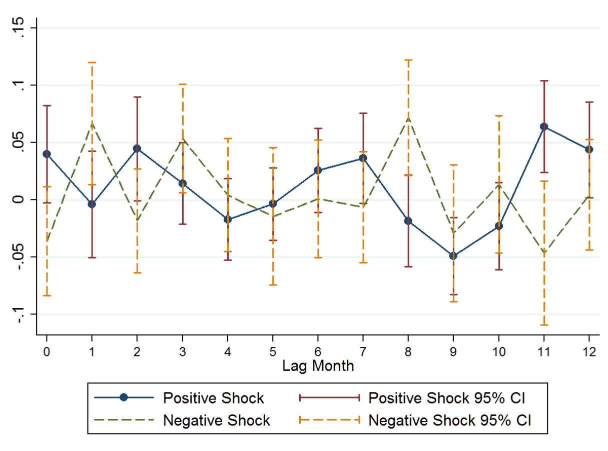
consistent with strategic behavior on the part of oil and natural gas firms we again urge caution in interpretation of these findings.

6 Methodological Implications: Dispatch Models in the Electricity Sector

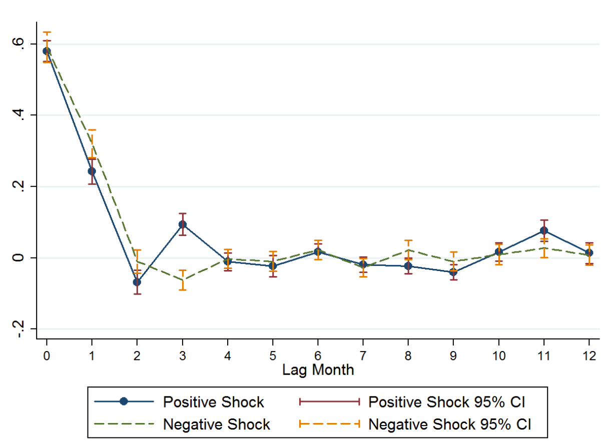
The above results have implications for a large class of studies that examine the electricity sector. In order to study the impact of different regulatory policies and market events in the electricity sector, economists must be able to evaluate how observed generation levels of different power plants compare to an efficient baseline. In a perfectly efficient market electric power generators would be dispatch in order of cost: in times of low demand only efficient, low cost plants would be used to meet electricity demand. Less efficient higher cost plants would only be used to meet demand during times of high demand.

In order to study divergence between observed generation and an efficient baseline a common approach is to use a least cost dispatch model. A dispatch model is effectively an industry level marginal cost curve of electricity producers. In a dispatch model, each power plant is indexed by its average cost of producing electricity. Fossil fuel fired power plants vary by efficiency (e.g., the heat rate of the boiler) and the cost of fuel used by the plant. Historically, for example, efficient coal fired power plants have a lower cost than inefficient natural gas fired power plants. However, as the price of coal increases or the price of natural gas decreases the dispatch order of power plants changes leading to relatively more natural gas being used to meet a particular level of electricity demand.

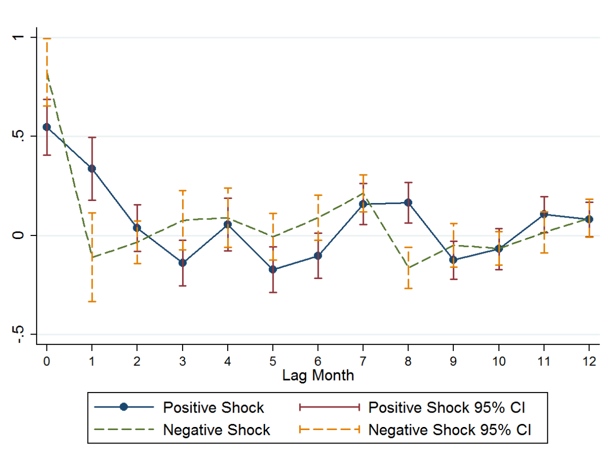
Many studies that evaluate changes in regulatory policy or market conditions on industry efficiency and welfare use fossil fuel spot prices to construct a dispatch model (Wolfram, 1999; Borenstein et al., 2002; Mansur, 2007). Power plants could, however, base their bidding and production decisions on actual procurement costs rather than spot market prices. As demonstrated above, there is an adjustment lag between fossil fuel spot prices and the procurement receipt prices for the power producers. This lag varies systematically by fuel type and to a lesser extent by direction of price change and regulatory status. This implies the general approach of approximating power



(a) Coal Transactions



(b) NG Transactions



(c) Oil Transactions

Figure 5: Pass-through Elasticity: Positive vs. Negative Shocks

Note: a positive shock means an increase in the relevant spot market price.

producers fuel input costs based on market spot prices might not reflect the real costs of production at the unit or the aggregate regional level. If this is true, it would be problematic to further infer the competitive counterfactual costs and compare with the actual costs to calculate deviations from an efficient baseline.

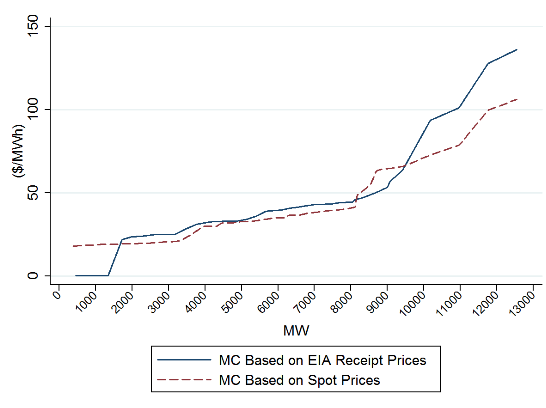
In this section, we highlight the implications of our empirical findings by comparing monthly dispatch models for different U.S. regions. To do so we construct dispatch models using month level fossil fuel spot prices and compare them to dispatch models based on observed receipt prices in our data. We then quantify the differences between the two sets of supply curves. Ideally we would compare those curves before and after an episode of electricity market deregulation, but unfortunately the fuel cost data is only available from 2002 on, shortly after the wave of electricity market liberalization ended.[20]

In order to construct the market-level competitive supply curves, we calculate marginal costs of each generating unit, based on unit specific heat rates. We first calculate the production efficiency (fuel input per unit of output) of each generating unit based on hourly operational information from EPA Clean Air Market data and then multiply by fuel prices (in addition to emission costs where they are relevant) to obtain unit marginal costs. Then we determine the market dispatch at different levels of aggregate demand based on least cost dispatch, often called "merit order" dispatch. Consistent with the literature, we combine unit marginal costs with unit capacity (maximum hourly generation within a year as a proxy). The competitive supply curve is therefore a step-wise function based on the dispatch order and the unit capacities.

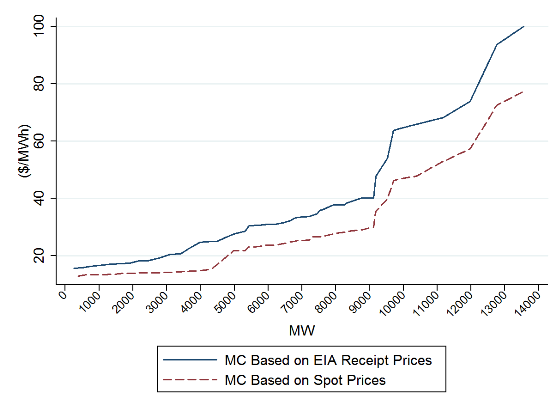
To save space we focus on the year 2012 when fossil fuel prices fell to historically low levels and on two wholesale electricity markets studied by previous literature: California (CAISO) and Pennsylvania, New-Jersey, Maryland (PJM). We do this for four different months in order to understand deviations between the two approaches given different patterns of electricity demand. We estimate electricity supply curves for both markets in January, April, August and October of 2012.[21] A comparison of the constructed optimal dispatch supply curves is shown in Figure 6

[20]The states that choose to deregulate and when they deregulated are potentially non-random so comparing dispatch models across regulated versus de-regulated states may be misleading.

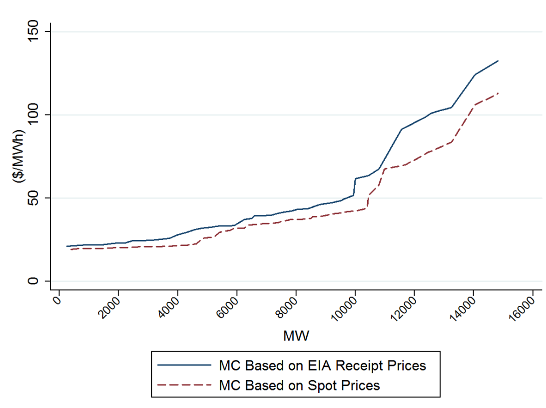
[21] We do the same analysis for 2008 when fossil fuel prices spiked. The results are presented in the Appendix. We find divergences in the counterfactual supply curves at least for some months, though the evidence in not as strong. Other months and years are available upon request.



(a) January



(b) April



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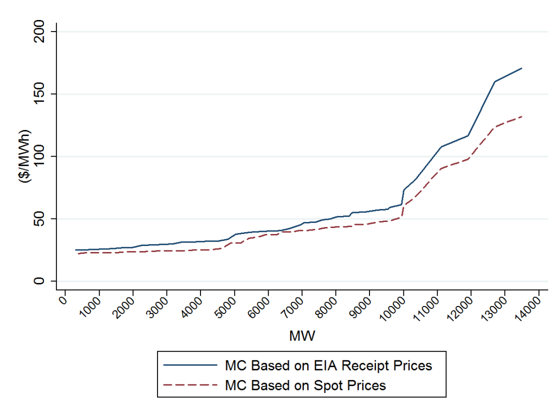


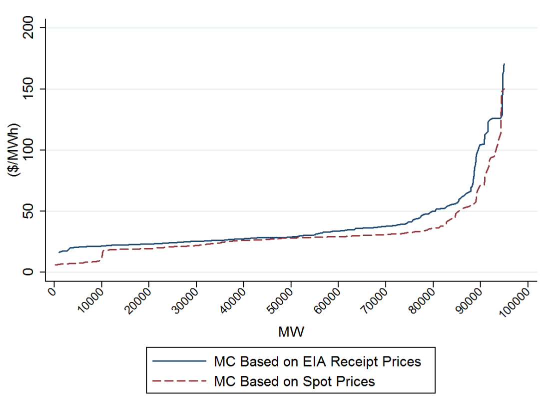
(d) October

Figure 6: Constructed Counterfactual Supply Curves: CAISO 2012

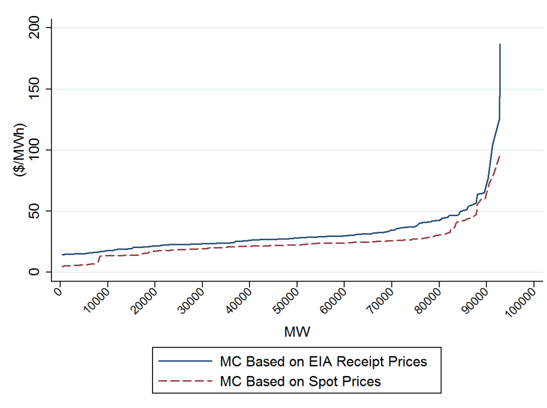
and 7 for CAISO and PJM respectively. There is divergences between the two sets of constructed counterfactual supply curves in both markets.

The difference in estimated cost for serving a particular level of demand is largest in CAISO and varies across demand levels and month of the year. In January the largest gap is at the highest levels of demand where the receipt price-based supply curve is far above the spot price-based supply curve. In April there is gap across all levels of demand and that gap grows as demand increases. In August and October the gap is much smaller. In PJM the gap between the two counterfactual supply curves is much smaller, although some of that is attributable to the larger range of estimated marginal costs in PJM. Across all four months and most demand levels the receipt price-based curve is above the spot price-based one.

We then seek to quantify the divergence between the spot price and receipt price based counter-



(a) January



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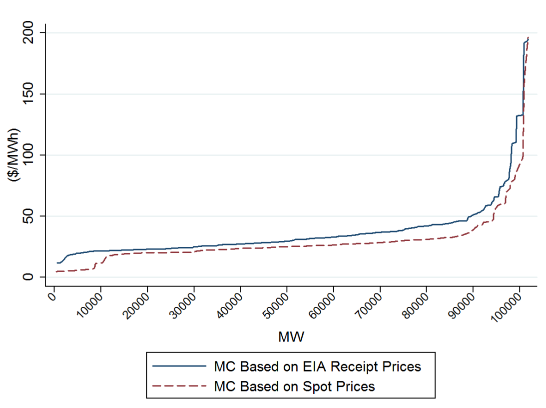

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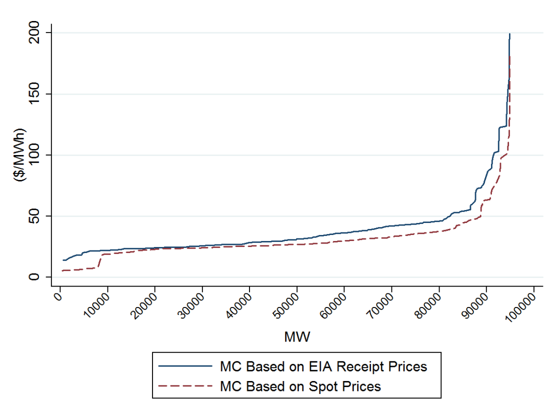

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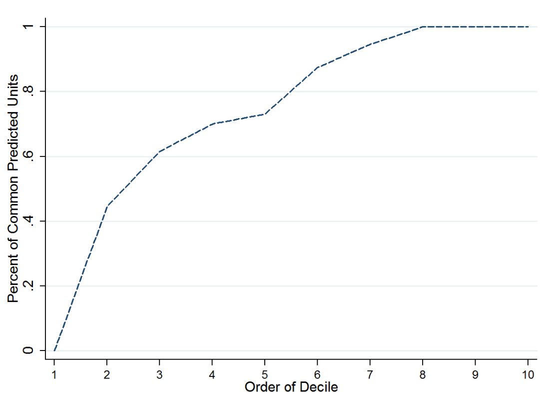
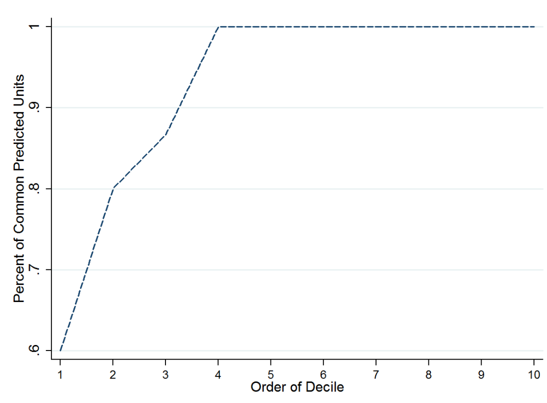
Figure 7: Constructed Counterfactual Supply Curves: PJM 2012

Note: units with abnormally high marginal costs (above 200 $/MWh) are excluded for better visualization.



(a) January



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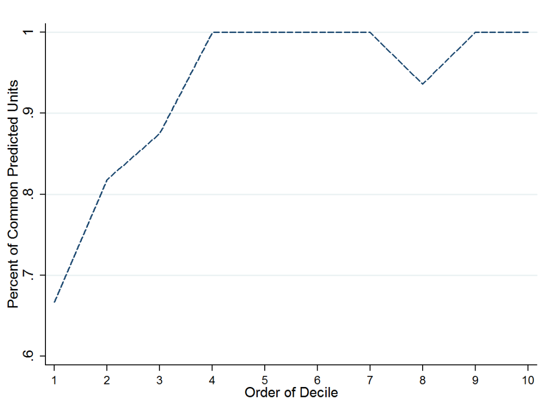

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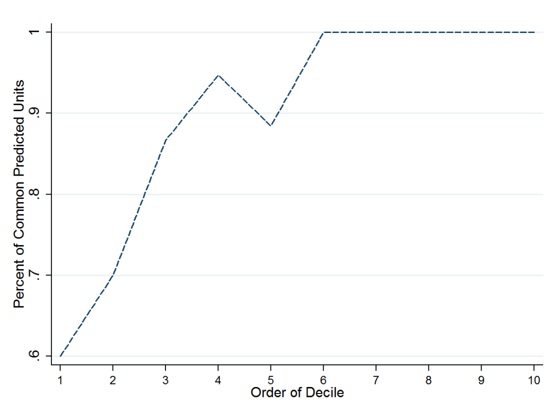
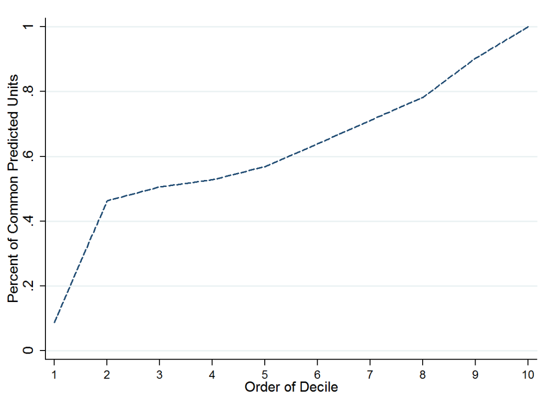


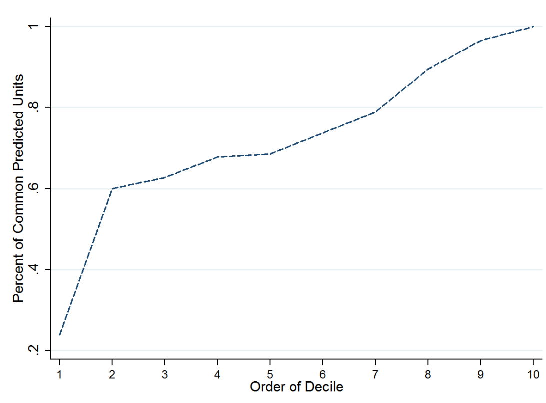
(d) October

Figure 8: Dispatch Algorithm Comparison: CAISO 2012

Note: the graphs show the percent of commonly predicted units online under two models, weighted by the number under the spot-price model, at different demand levels (deciles of regional capacity levels) in CAISO. Note that environmental costs are not incorporated since permit price data is missing in 2012.



(a) January



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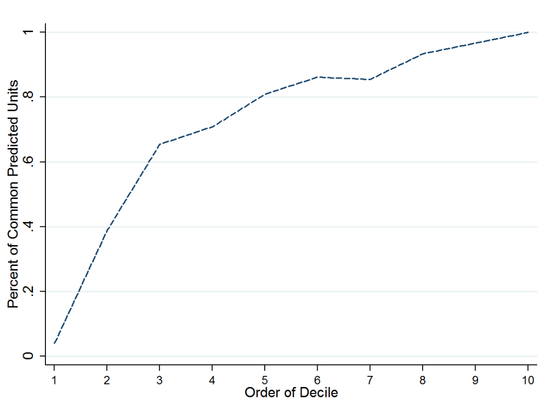

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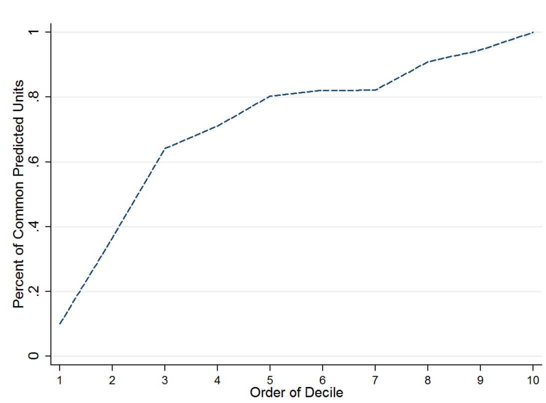


(d) October

Figure 9: Dispatch Algorithm Comparison: PJM 2012

Note: the graphs show the percent of commonly predicted units online under two models, weighted by the number under the spot-price model, at different demand levels (deciles of regional capacity levels) in PJM. Note that environmental costs are not incorporated since permit price data is missing in 2012.

factual supply curves. We measure the differences in dispatch order by checking the units dispatched to meet different levels of demand when the cost curve is constructed using spot fossil fuel prices versus actual procurement costs. We track the number of common units predicted to be turned on at different deciles of regional supply capacity in four months chosen to evaluate differences in the supply curves across seasons.

Figures 8 and 9 show the results of this exercise for CAISO and PJM. Each figure compares two statistics: (1) the number of units predicted to be online when spot prices are used and (2) the number of units predicted to be online under the model based on procurement costs which are also predicted to be online when spot prices are exploited. For example, 20 particular units might be predicted to be online by the spot-price dispatch model for a given level of regional electricity demand. There might be 22 units predicted to meet the identical level of demand by the procurement cost model (since each generating unit has a different capacity). However, it could be that only 16 of those 22 units are shared by both models. The common units are therefore 16. Figures 10 and 11 report this information in percentages for clarity. In the above example that particular decile of demand would be given a value of 0.8.

In both the California and PJM markets, there are certain months (e.g., January 2012 for California, and January and April 2012 for PJM) when there are notable gaps between the sets of predicted units online under the two sets of supply curves. The implication is that using fossil fuel spot prices to simulate dispatch counterfactuals under a competitive environment can be problematic for the levels. If we think, arbitrarily, that 80% of common units is a cutoff for good similarity of dispatch, as shown in Figure 8(a) and Figure 9(a), in January 2012 the demand has to reach the 6th and 8th decile of region capacity in California and PJM markets respectively to achieve that level of similarity in simulated dispatch of a competitive environment. As a result, studies using spot prices to investigate the impact of a regulatory or market event above that market would be a reasonable approximation. Intuitively, as demand increases more units have to serve demand such that the number of common units naturally rises and the two sets of predicted units eventually converge as all units come online to serve peak demand.

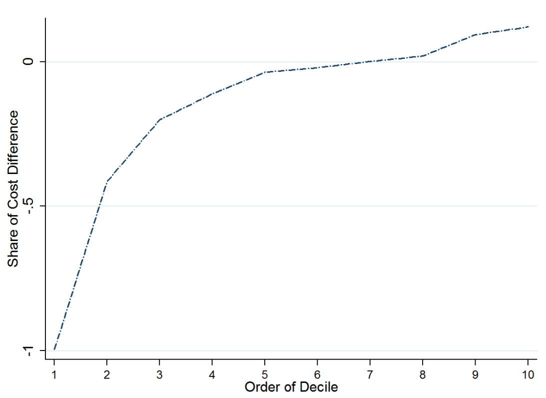
The findings are consistent with our empirical findings above. Natural gas fired units make up a large portion of overall supply while coal provides comparatively little. In California employing spot prices is likely a good proxy for the actual marginal costs of power plants. Conversely, in PJM much of the market is served by coal generation. One clear feature of Figures 8 and 9 is that there is a much greater divergence between the spot-price and procurement-cost dispatch models in PJM relative to California. Given the observed adjustment lag between coal spot prices and procurement costs, the difference of dispatch is more likely to occur when coal units are supposed to serve the market. Nevertheless, we still find instances of discrepancy in the dispatch order in California when fossil fuel spot prices are used to construct counterfactual competitive supply curves.

We also show deviations in the total costs to meet certain levels of demand under the two sets of simulated competitive counterfactuals. If there are sizable deviations, then using the total costs under the counterfactuals based on spot prices to compare with the actual costs and determine deviations between the wholesale price of electricity and costs of the marginal unit would overstate or understate inefficiencies due to market power or other market characteristics.

Figures 10 and 11 show deviations between the level of marginal costs for California and PJM markets between the two dispatch models. We measure deviations by calculating differences between the total costs based on EIA-reported power plants procurement costs and those based commodity spot prices as a share of the costs based on spot prices. The Figures show that cost deviations can be as large as 35% for California market in 2012. In PJM market, despite the large differences at low level of demand, the deviations can still maintain as high as 30% - 40% when demand is high.

To put the statistics in context, we compare them with the shares of added costs of power procurement that exceeded the marginal costs under a competitive market in Borenstein et al. (2002) and Mansur (2007). Borenstein et al. (2002) states that the share of added costs due to market power is 33% during June 1998 to October 2000 in the California electricity market, with the number varying from 0 to 60% across different months. The share of cost deviations represent a similar magnitude.

This section does not imply that studies using spot price dispatch models are flawed. Rather, it highlights that using spot prices could possibly lead to differences in the magnitudes in findings of those studies. For example, studies using a differences-in-difference design may difference out these



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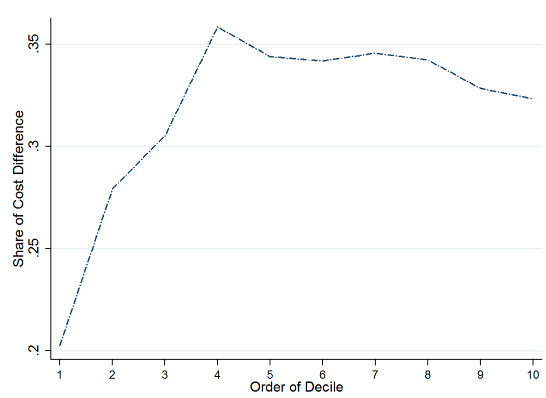

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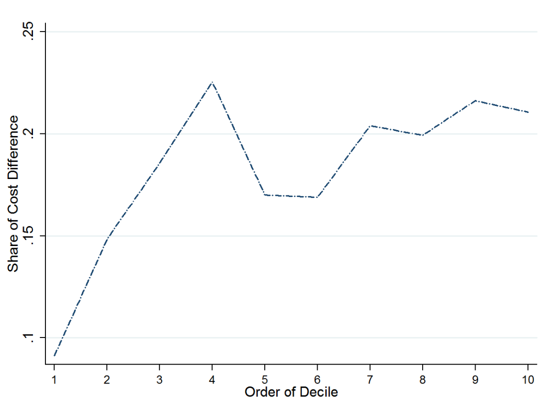

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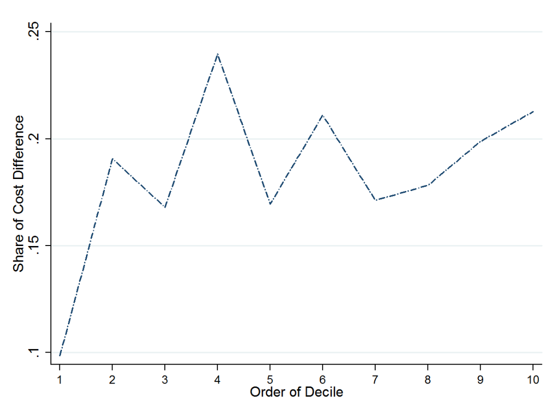
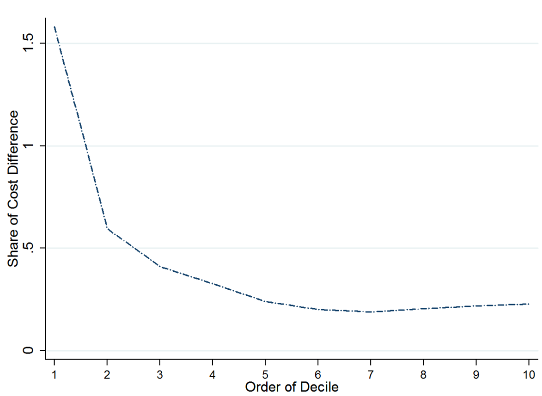
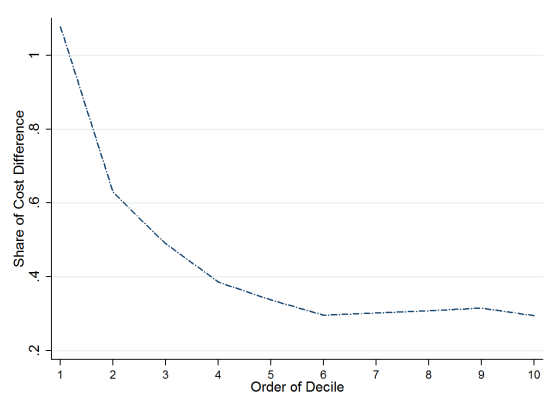


(d) October

Figure 10: Total Cost Differences: CAISO 2012



(a) January



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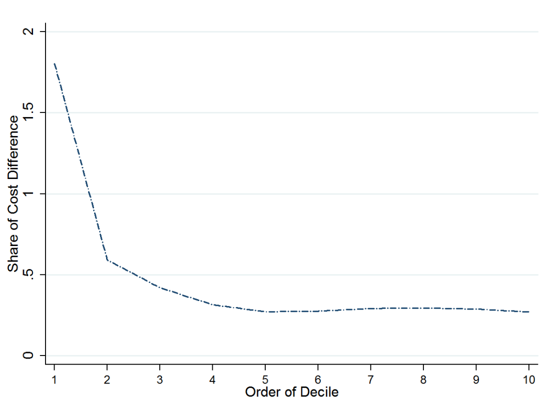

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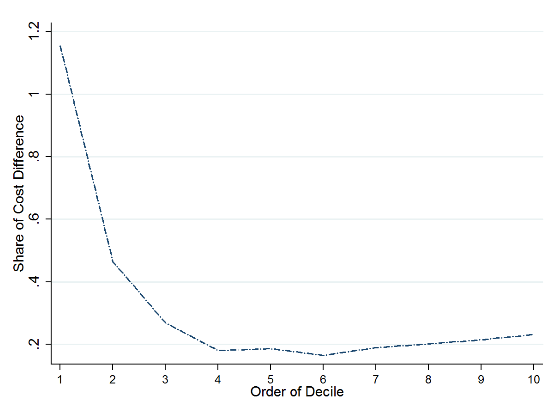

(d) October

Figure 11: Total Cost Differences: PJM 2012

costs level effects.[22] Further, fuel procurement is only one part of the costs of operating plants with operations and maintenance also playing an important role. This study lacks the ability to infer any mechanism for systematic bias in estimates which could result in using spot price dispatch models. It is very possible that using spot prices makes no quantitative or qualitative difference. Future work is needed, possibly in the form of replication studies, in order to understand if spot prices leads to any effect in estimated implications of using spot prices rather than actual procurement costs. Power producers, for example, likely make bidding decisions using a more complicated process involving inventories, a history of fuel costs and forecasted fuel costs. As a result, future work studying how input price fluctuations impact bidding decisions seems like a reasonable path forward.

7 Conclusion

In this study, we investigate how commodity spot price changes are passed through to coal, natural gas and oil fired electricity generators. We are not aware of any previous study that clearly identifies differences in fuel input procurement costs. As a result, we contribute to the literature on both supply side pass through and energy economics by carefully documenting pass through behavior in this important market.

We find that, consistent with long term contracting, coal spot price pass through is very slow and very incomplete. There also appears to be no difference in pass through of coal spot market price changes even when grouping coal by type. As a result, we take this as strong evidence that coal spot price pass through is slow, incomplete and does not vary by the source of coal.

Conversely, natural gas pass through is rapid and nearly complete within the two months immediately following a spot price change. Pass through is more rapid in deregulated plants than regulated plants. There also appears to be differences in pass through as a function of the direction of spot price changes. Finally, oil exhibits similar procurement cost pass through as natural gas.

Our findings have implications for both the electricity and business sectors as an increasingly large share of electricity production occurs from natural gas. Volatility in natural gas market

[22] Our results suggest that pass through varies somewhat across regulated and un-regulated power plants, but it is not clear if these differences are systematic because we do not observe any episodes of deregulation during our sample period.

prices is quickly transmitted to procurement costs of power producers. If volatile procurement costs are subsequently passed through to electricity wholesale prices, it increases the difficulty to plan business and hedge against market uncertainty. As a result, further study is needed to identify how input procurement costs manifest in wholesale prices in the electricity markets. Further, retail users are increasingly moving to real time pricing schemes which directly exposes them to within month variation in wholesale electricity price. This can lead to undesirable welfare effects as volatility in monthly electricity bills disproportionately impacts low income households.

The results of our study also inform future studies in the electric power industry. The adjustment lag between fossil fuel spot prices and procurement receipt prices for power plants implies that spot prices do not always reflect the true opportunity costs of using the fuel. It has implications on how to apply the static model of measuring market power commonly used in the electricity market: when researchers construct regional supply curves, it might be appropriate to use relevant spot market prices to calculate the marginal costs of natural-gas-fired generators. For the marginal cost calculation of coal-fired generators, we should instead use observed coal receipt data from the E.I.A or other sources.

We also document evidence that natural fossil fuel spot prices changes are passed through to procurement costs more quickly in deregulated markets. However, our findings are not causal since we observe no variation in regulatory status across time in our data. Our results are consistent with existing literature which finds that deregulated electric utility firms bargain to pay lower costs for fuel prices in that we find differences in pass-through between regulated and deregulated natural gas power plants (Chan et al., 2013). We are not aware of any study which documented a discrepancy for natural gas power plants.

The pass through estimates provide suggestive evidence that the benefits of the major fall in natural gas prices have not been captured by natural gas extraction firms. The variation we exploit in this study is not from the fracking-induced price collapse in natural gas, but the near instantaneous pass through in natural gas spot prices to natural gas consumers suggest that inexpensive natural gas is passed through to electricity generators.

Our results also suggest possible opportunities of future work. One limitation of our study that we do not identify the contribution of different possible channels underlying the differences in pass-through by regulatory status nor price increases versus decreases for natural gas nor the differences between coal and natural gas. For instance, an inventory model might be a useful way to gain insights into empirical results for coal and natural gas pass through. A similar model may help explain asymmetries in pass through for price increases and decreases for natural gas. We leave such structural modeling to future work.

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