Isolating the Impacts of the Shale Revolution on the U.S. Energy Mix: Evidence from the Natural Gas Pipeline Network*

Matt Butner
Institute for Policy Integrity
New York University
matt.butner@gmail.com

Jonathan B. Scott
Energy Institute at Haas
University of California Berkeley
jbscott@berkeley.edu

October 14, 2019

Abstract

This paper estimates the long-run effects of the Shale Revolution on aggregate US electricity fuel mix using pre-existing pipeline infrastructure as quasi-random exposure to an abundance of natural gas. We find that more natural gas deliveries reduces the amount of electricity generated from both coal plants and wind turbines. Even though the Shale Revolution has been attributed as a key contributor to reducing greenhouse gas emissions from electricity in the United States, our counterfactual electricity mix implies a modest reduction in total greenhouse gas emission relative to estimates from U.S. government reports. Further, we calculate that a production leakage rate greater than 3.3% would cancel out benefits of reduced carbon emissions, highlighting the importance of efficient emissions management in natural gas production.

JEL classification codes: L94, L95, Q33, Q35, Q53

*Preliminary and incomplete. Please do not circulate without the authors' permission.

1 Introduction

The United States has undergone a "Shale Revolution" as innovations in drilling and extraction of natural gas has opened up unconventional reserves in shale rock. One of the most contested aspects of this resource boom is the effect of more natural gas production on total greenhouse gas emissions. Because natural gas emits less greenhouse gas per unit of energy than coal and petroleum, some argue that natural gas can serve as a green bridge to a low-carbon future by replacing these dirtier resources (Tour, Kittrell, and Colvin, 2010). Even an official report the U.S. Energy Information Agency points to "the emissions reductions from shift towards natural gas" as the number one contributer to greenhouse gas emission reductions for every year since 2005 (EIA, 2018, p. 12). However, simulation exercises suggest that abundant natural gas at a low price can crowd out investment in other low carbon technologies like wind turbines and solar panels (e.g., Newell and Raimi, 2014). This preempts further reductions in greenhouse gas emissions, making the overall impact of more natural gas production on greenhouse gas emissions ambiguous.

In this paper, we empirically document the impact of more natural gas production on greenhouse gas emissions by evaluating the causal impact of more natural gas production on the U.S. electricity mix, providing a counter-factual fuel mix for the United States as if the Shale Revolution had never occurred. In general, it is difficult to disentangle how much of the change in fuel mix over the past fifteen years has been caused by the Shale Revolution and not by other factors.[1] Most notably, there is a problem of simultaneity in that the quantity of natural gas deliveries and realized fuel mix are co-determined by supply and demand. In this paper we address this challenge using the infrastructure of natural gas pipelines prior the Shale Revolution to construct a state-specific measure of exposure to more natural gas. This quasi-random variation in exposure to out-of-state natural gas production and deliveries allows us to estimate the long run substitution patterns of different electricity generation technologies using a generalized difference-in-differences and two-stage least squares approach.

We find more national gas production reduces the share of electricity generated by coal as well as wind turbines within a state. The reduction in electricity generated from coal is largely from short run displacements by natural gas, where as the reduction of the share of electricity generated from wind turbines is from long run reduction in wind turbine capacity investment. Further, the effect of more natural gas production on total green house gas emissions is smaller than claims made by the natural gas industry and government reports, due to the

[1] Examples of coincident events in the electricity power sector include a number of state and federal policies to encourage the adoption of more renewable generation, a larger build out of new natural gas electricity generators, as well as an economic downturn that reduced demand for electricity

crowding out of investment in wind turbines and the decline of electricity generated by coal even in the absence of the Shale Revolution. Our results are robust to estimation on various subsamples, alternative instruments, and alternative definitions of pipeline connectedness.

Most directly this paper is contributing to the rich literature evaluating the economic consequences of the Shale Revolution. Examples include the impact of more natural gas production on local labor markets and income payments (Feyrer, Mansur, and Sacerdote, 2017), manufacturing (Allcott and Keniston, 2017; Gray, Linn, and Morgenstern, 2019), welfare and natural gas prices (Hausman and Kellog, 2015), health (Currie, Greenstone, and Meckel, 2017), education (Cascio and Narayan, 2015), housing values (Muehlenbachs, Spiller, and Timmins, 2015), crime (James and Smith, 2017), and other amenities (Bartik et al., 2019). We depart from this line of research in two ways. First, noting that the economic consequences of the Shale Revolution reach beyond the local geography, primarily through the natural gas pipeline, we document the economic impact of national U.S. production of natural gas on the national electricity mix. Second, we are the first to utilize the legacy natural gas pipeline network as a source of identifying variation. Given the reliance of the natural gas market on natural gas pipelines, this method is straightforward, and is an improvement upon the existing studies that only look at cross-sectional differences in resource availability.

In contrast to some existing empirical work on the causal effects of the Shale Revolution, our approach does not restrict us to identify off of variation across narrowly defined geographic regions, creating the potential for attenuation from spillover effects. In this paper, we exploit quasi-random, out-of-state production of natural gas, which is plausibly exogenous to in-state factors governing the extraction and use of natural gas resources. We leverage the pre-existing natural gas pipeline infrastructure to infer the level in which one state's production has the potential to affect another state's consumption, independently from other, potentially confounding, factors. In this sense, we are able to overcome potential bias from confounding unobservables related to a state's energy investment choices; for example, a state's aggressive policies against fossil fuel consumption *and* production.

For the possible scenario in which a single "consuming" state may have significant influence over the production of a "producing" state, we propose an alternative instrument which combines variation in exposure to production *potential*—mainly, the total shale area in which a state is connected to—with the timing of the upswing in national production. In doing so, we maintain out-of-state variation in production potential, while mitigating concerns related to endogenous relationships between states. The alternative approach produces quantitatively similar results.

Furthermore, our strategy allows us to isolate states more exposed to the impacts of natural gas production from those less impacted. Whereas, the Shale Revolution was largely a national-level treatment, by exploiting the pipeline network, we are able to narrow in on extent of exposure for each state. This allows us to partition states into analogous "treatment" and "control" states, enabling implementation of a generalized difference-in-differences approach.

Broadly this paper is contributing to the understanding of investment and substitution in response to a technological innovation. Because of the readily defined production technologies to generate electricity a number of researchers have evaluated how exactly more natural gas, or lower natural gas prices, will impact the fuel mix and total greenhouse gas emissions using an energy-economy simulation model (Newell and Raimi, 2014; Shearer et al., 2014; Gillingham and Huang, 2019). These models show how lower natural gas prices will lead to less electricity generated by coal and renewable resources. While informative, these simulation models assume that the investment and dispatch of electricity is governed by perfectly rational social planner with the goal of minimizing system cost, and are only robust to changes in the model parameters regarding the cost of generation or system demand. As a result, they fail to capture the extant complexity and institutional details regarding electricity investment, generation, and distribution.

In the United States, electricity generation is governed by bilateral contracts or economic dispatch where firms have the ability to exercise market power or are constrained by transmission capacity, sometimes inconsistent with the cost minimizing outcome. Further, investment for regulated utilities is motivated by capital expenditure not minimizing expected costs of production, and can be distorted by policies such as tax credits or technology mandates. Our method, using observed outcomes in a causal framework, reconciles the results presented in the simulation model (that more natural gas production reduces the amount of electricity generated from coal and renewables) with the retrospective reports looking at carbon emissions in the U.S. (that largely ignore the substitution of natural gas and renewables), all the while taking into account the complex institutions influencing the electricity mix in the U.S.

Empirically, a number of papers have documented the response of electricity generators to lower natural gas prices. Examples include the effect of natural gas prices on marginal emission rates (Holladay and LaRiviere, 2017; Cullen and Mansur, 2017; Knittel, Metaxoglou, and Trindade, 2016; Johnson, LaRiviere, and Wolff, 2019), and the effect of natural gas prices on coal to gas switching and market structure (Knittel, Metaxoglou, and Trindade, 2019), electricity prices (Linn and Muehlenbachs, 2018), capacity investment (Brehm, 2019). Largely these papers use longitudinal natural gas price variation resulting from the Shale Revolution, and typically look only at switching the fuel type from coal generation to natural gas. Our approach builds on these papers using a novel instrument for variation in exposure to the Shale Revolution, and diverges from them in two ways.

First, we are unique in looking at the effect of natural gas production, not natural gas prices. We do this in-part because the Shale Revolution was largely a shock to the quantity of natural gas produced by a given well, and the quantity produced from natural gas and oil wells differ from conventional resource extraction problems (Anderson, Kellogg, and Salant, 2018). By evaluating the effect of more natural gas production, we can speak to issues regarding quantity based policies such as bans on hydraulic fracturing and leakage from existing natural gas well. Second, we are the only ones looking at the effects of the Shale Revolution on the output and capacity of all fuel types, not just coal generation. By looking at all fuel types, we are able to better characterize the complete effects of the Shale Revolution and present a counterfactual fuel mix thereby speaking to the broader impacts on greenhouse gas emissions in the electric power sector.

The balance of this paper is as follows. Section 2 provides background on the Shale Revolution, investment and dispatch of electricity in the United States, and trends in the electricity industry over the past two decades. Section 3 outlines our empirical strategy leveraging the legacy natural gas pipeline network, while section 4 walks through the data we use. Section 5 lays out our main results. This includes the effect of natural gas deliveries and national production on total electricity generation and electricity generation share by fuel type. In Section 6 we present our counterfactual fuel mix and how the Shale Revolution impacted carbon emissions from the electricity power sector. Section 7 explores some of the mechanisms including how the Shale Revolution impacted natural gas prices and the implementation of Renewable Portfolio Standards, and outline the implications of our results for a "break-even" methane leakage rate that offsets the environmental benefits of the Shale Revolution. Section 8 concludes with a discussion.

2 Background

The existence of large natural gas and petroleum reserves in shale has been long established. However, these reserves were largely seen as being uneconomic and hard to access because the resources were interlaced in a honeycomb of shale rock, much unlike the large pools of oil and gas extracted from conventional wells. The economics of natural gas production changed by the introduction of two technologies attributed to George Mitchell of Chesapeake Energy in the Barnett formation in Texas in the late 1990s, which became wide spread commercially in 2005.[2] The first technology was hydraulic fracturing, where large quantities of water, sand, and other chemicals are pumped into a drilled well at high pressure. This breaks up the shale rock, freeing the natural gas and petroleum for extraction. The second technology impacted the depth and reach of wells by drilling down to over 10,000 feet, much below the water table, and then drilling horizontally up to an additional 10,000 feet. This horizontal drilling increased the cost of drilling a well but increased the production of a single wellhead by an even larger factor.

The impact on total U.S. production on natural gas is apparent. Dry natural gas production from shale production went from 4.2 billion cubic feet per day (bcf/day) in 2005 to almost 70 bcf/day in 2019.[3] Geographically, natural gas production occurs predominately in Texas, North Dakota, and Pennsylvania, with the most productive natural gas area changing overtime. Even though natural gas production is concentrated in a few areas of the United States, natural gas can be transported efficiently over long distances through interstate natural gas pipelines. Ever since the U.S. Federal Energy Regulatory Commission issued order 636 in 1992, these pipelines have been deregulated, unbundled, open to third parties, offering services at a market based rate. Figure 1 shows how these natural gas pipelines have increased delivered natural gas for electricity production in almost every state despite the production increasing in a few key areas.

The most immediate impact of more natural gas production is on the price of natural gas. The Henry Hub natural gas price went from $8.69/mmBtu in 2005 to $2.75/mmBtu in 2012, as shown in Figure 2.[4] The reduction in the price of natural gas changes the economics of electricity production. For one, it increases the profitability of electricity generators using natural gas as a fuel. One measure of this profitability commonly used by natural gas electricity generators is the "spark spread", representing the difference between the price of electricity and cost of production from a natural gas plant per unit of electricity sold.[5] As the spark spread increases, natural gas became more attractive as a fuel to generate electricity relative to other sources of electricity generation.

Electricity in the United States is generated by a diverse mix of resources. Since the 1950s, around half of all electricity in the United States has been generated by power plants using

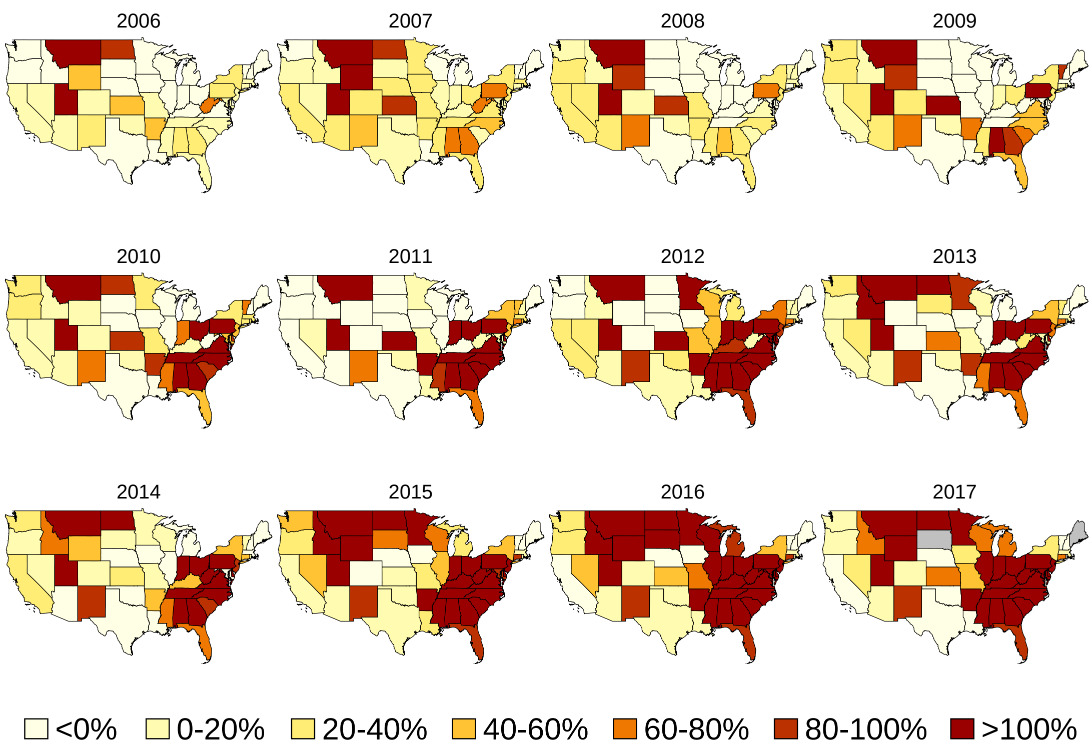
[2] Throughout we consider 2005 to be the beginning of the Shale Revolution even though it was not acknowledged in popular press until the late 2000s. This is consistent with many reports from the U.S. Energy Information Agency reports that document how the Shale Revolution impacted the electricity sector. Our empirical approach generalizes this discrete start time by exploiting production as a continuous measure.

[3] See Dry Shale Gas Production Estimates by Play at https://www.eia.gov/naturalgas/data.php.

[4] See Annual Henry Hub Natural Gas Spot Price at https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm. mmBtu stands for million British thermal units. Henry Hub is a natural gas distribution hub in Louisiana and lends its name to the New York Mercantile Exchange futures gas contract.

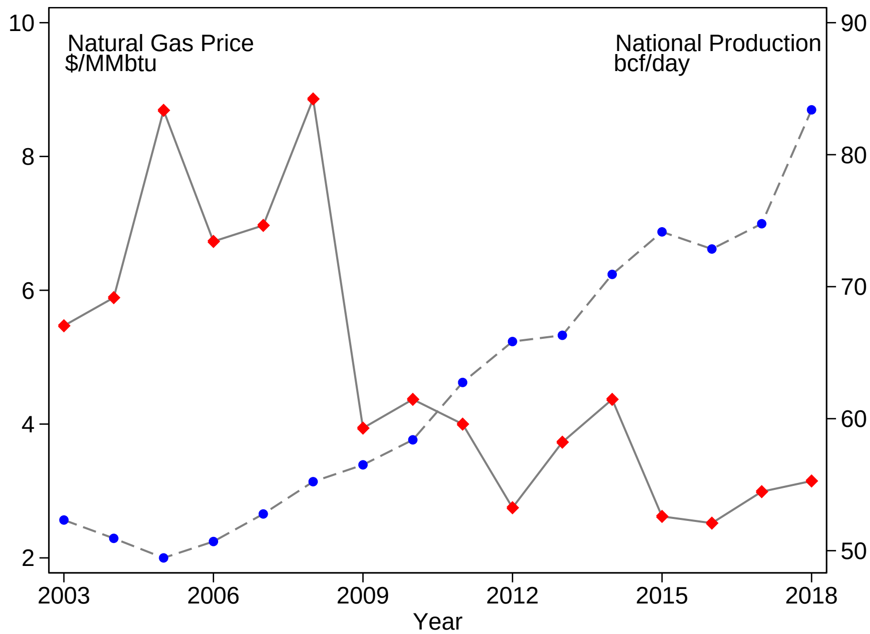
[5] Electricity Power Price ($/MWh) - [natural gas price ($/mmBtu) * heat rate (mmBtu/MWh)]

Figure 1: National Impact of the Shale Revolution



Note: % change in volume of natural gas delivered to electric power customers from 2005, EIA. The EIA reports no data for South Dakota and Maine in 2017 to avoid disclosure of individual company data.

Figure 2: Natural Gas Price and Production



Note: Natural gas price is the Henry Hub spot price for natural gas from EIA in nominal USD. Production is total dry production in the US. This documents, in part, the impact of the Shale Revolution on the price of natural gas.

coal as a fuel source. The fuel sources contributing to the residual amount of electricity has changed overtime, however have been primarily composed of nuclear, hydro, natural gas, and petroleum. Petroleum, as a fuel source for electricity, fell out of favor after the oil and energy crises in the 1970s. Presently, there is limited availability to build a new large hydroelectric dam, and significant regulatory hurdles and engineering costs to building a new nuclear power plant. In the early 2000s there was a build out of a new technology to generate electricity using natural gas, a combined cycle combustion engine, that greatly increases the efficiency of electricity production. Recently, there has been a build out of renewable technologies in part due to government subsidies and a significant reduction in the levelized cost of production.

The political economy determinants of the U.S. fuel mix is complex and varies from state to state. Because of the high fixed costs associated with the generation and transmission of electricity, the producers of electricity have historically been vertically integrated investor or publicly owned monopolies operating under rate-of-return regulation. These regulated utilities would be guaranteed a return on any prudent capital investment. Following the success of the deregulation of natural gas pipelines, trucking, railroads, and airlines, there was a movement to do the same for the electricity industry. A handful of states broke up vertically integrated utilities, changing the incentives for investment. At the same time formal wholesale markets and entry from merchant electricity generators were encouraged by federal policies, however the nascent wholesale markets were only in select areas.[6] As a result, the geography of regulation and restructuring in the U.S. is in no way uniform, and, the institutional details contributing to the U.S. fuel mix varies from state to state significantly.

The U.S. fuel mix is realized along two margins. In the short run, when the generation capacity of all resources is fixed, the mixture of fuels used to generate electricity is governed by a wholesale electricity market or bilateral contracts. The objective is to generate enough electricity to meet relatively inelastic demand from load serving entities while minimizing total cost of production. This is accomplished in wholesale markets by a impartial market operator solving a security constrained economic dispatch algorithm that takes generation offers from electricity generators to determine which units are dispatched to generate electricity. To the extent to which lower natural gas prices lower the cost of production for natural gas plants, the natural gas plants might displace other units in the "merit order" causing a short run change in the fuel mix.[7] We expect most fuel substitution in the short run to be natural gas for coal and petroleum, as nuclear is hardly ever on the margin, and wind, solar, and hydro are not always dispatchable. The same logic applies to short run bilateral contracts, even if contracts are not transacted on a formal wholesale market. Evidence of this short run switching of the merit order is presented by Linn and Muehlenbachs (2018); Fell and Kaffine (2018).

There is an additional way in which more natural gas production and a lower natural gas price due to the Shale Revolution can impact other fuel types in short run equilibrium. If natural gas is setting the price in the competitive wholesale market, and the natural gas plants pass-through the reduction in operating costs from a lower natural gas price, this will decrease the wholesale market price. This decreases the revenue for all inframarginal electricity generators as well, even if they are not directly displaced in the merit order. If a plant's margins are small, this might make it optimal for a plant to shut down or become inactive in the short run.

The long run fuel mix is determined by the entry, exit, and investment decisions of electricity generators. The incentives for each of these actions vary according to whether the

[6] Federal Energy Regulatory Commission (FERC) orders 888 and 889 in 1996 set the stage for competitive wholesale markets, FERC order 2000 in 1999 encouraged Regional Transmission Organizations to form as planning authorities.

[7] The merit order is the ranking of electricity generating units from the lowest required price to the highest required price and represents the supply curve for providing electricity in wholesale markets. It is referred to as such because the resources requiring the lowest price have "merit" in the dispatch.

entity is regulated under rate-of-return or is a merchant electricity generator subject to the market conditions. Overall, however, the dynamic decision to adjust capacity is based on the expected price of electricity, fuel price, and fuel availability in future periods. As the price of natural gas declines due to improved production technology we'd expect the following in the long run: (1) more investment in new natural gas capacity to meet demand growth and replace retirements, (2) relatively less investment in new capacity of other resources such as coal plants and wind turbines to meet the same demand growth and replace retirements, and (3) plants switching from coal-powered to gas-powered generation because coal plants have the ability to be converted into natural gas plants.

This substitution of fuel capacity in the long run is based on relative fuel prices, not electricity prices. To illustrate the point, consider the case of a public utility advertising a competitive, technology neutral, Request For Proposals for new generation capacity.[8] As the natural gas price decreases, due to advances in natural gas production technology, the merits of a bid for a new natural gas plant relative to a wind turbine increases, increasing the long run capacity in natural gas.

Relatedly, a utility considering the purchase of wind power in a long term contract will compare the wind purchase price to what would be it's forgone cost of operation. If the utility owns natural gas generation assets, a lower natural gas price implies a lower forgone cost of operation. The utility must demand a lower purchase price and could prevent marginal wind projects.

The development of new resources, however, does depend in part on the market price for electricity, especially in the case of independent power producers. For example, merchant wind turbine financiers trying to sell into the wholesale market will be less optimistic about their investments when a lower natural gas price suppresses the wholesale energy prices. As a result, locations where wind generation is marginally economic might not invest in wind turbines just yet due to lower natural gas prices.

Overall, we expect more natural gas deliveries to be associated with less generation from coal in the short run, the mechanism is the lower natural gas price decreasing the cost of production from existing gas plants creating a re-shuffling of the merit order and a decrease in the wholesale market price. In the long run we expect more natural gas deliveries (lower natural gas price) to be associated with less coal capacity (generation) and wind capacity (hence generation) because of switching of fuel capacity for marginal demand growth and coal-to-gas switching.

[8] For example, see PacifiCorp's request for proposals here: http://www.pacificorp.com/sup/rfps.html

3 Empirical Strategy

This paper aims to identify the causal effect of the Shale Revolution on the share of electricity generation attributed to different sources of energy. As natural gas produced in one state is not restricted to stay in and be used by that state, estimation off of state-level production will naturally violate the stable-unit treatment value assumption due to leakage among outside states. More generally, the national Shale Revolution is interpreted as a national-level shock, where new hydraulic fracturing techniques allowed inexpensive natural gas to be attainable to much of the lower 48. Therefore, of primary interest is the causal impact of this national-level production boom on state-level energy decisions. However, a naïve approach which regresses individual state energy outcomes directly on national-level production may be confounded by other trending, unobserved, determinants of these outcomes. Given an absence of a true comparison group, leveraging the pipeline network is a crucial component in our identification of the causal effect of the Shale Revolution on energy choice outcomes.

In this paper, we use out-of-state variation in production and production potential to isolate the impact of natural gas supply through predicted deliveries. As natural gas is, nearly exclusively, transported by pipeline, we make use of this infrastructure as a well-defined network. Furthermore, we anticipate out-of-state production, or production potential, linked by state-to-state segments of this network to be plausibly exogenous in our setting.

We begin with a matrix which defines the links between states over time, $\mathbf{W}_t$. These links characterize the operations of the natural gas pipelines, and more specifically, the shares of one's own production that is delivered to another state. Let $i = 1, \ldots, N$ denote receiving states and $j = 1, \ldots, N$ denote producing states. Let element $w_{ijt} \in \mathbf{W}_t$ represent the fraction of natural gas production from state j delivered to state i in time t, where $w_{ijt} = 0$ for all $i = j$. Note that a column in $\mathbf{W}_t$ is not restricted to sum to one, as a state may keep a proportion of its production. For row vector of weights, $\mathbf{W}_{it}$, of length N, and production column vector at time t, $\mathbf{Q}_t$ of length N, define the total delivered gas to state i in time t as the following.

$$gas\ delivered_{it} = \mathbf{W}_{it} \cdot \mathbf{Q}_t = \sum_{j \in N} w_{ijt} \times q_{jt} \tag{1}$$

for production in state j, $q_{jt} \in \mathbf{Q}_t$. Elements in $\mathbf{W}_{it}$ define the extent to which other states impact state i. To this effect, matrix $\mathbf{W}_t$ is similar to what is often referred to in environmental economics as a source-receptor matrix (Deschenes and Meng, 2018).

We can define a state's natural gas supply as the sum of some portion of in-state production and the amount of gas delivered from out-of-state. That is, $S_i = \textit{gas delivered}_i + \phi_i \cdot q_i$, where S_i defines i's total supply of natural gas. Any given period, the state keeps some portion of its production, $\phi_i \in [0,1]$—where $\phi_i = 1 - \sum_{j \in N} w_{jit}$—and distributes the remainder, $1 - \phi_i$, to other states.

Whereas in-state production could be driven by various, potentially confounding factors—such as state energy policies and institutions—we anticipate out-of-state production (or production potential) to be orthogonal to such factors. To that end, this paper isolates *predicted* gas deliveries as a plausibly exogenous component of natural gas supply for a single state. We wish to estimate the following equation, where we change notation for production to indicate empirical data.

$$\begin{aligned} \textit{generation share}^f_{it} &= \beta_1 \cdot \textit{gas delivered}_{it} + \beta_2 \cdot \textit{production}_{it} + \gamma_i + \delta_t + \varepsilon_{it} \\ &= \beta_1 \cdot \sum_{j \in N} w_{ijt} \times \textit{production}_{jt} + \beta_2 \cdot \textit{production}_{it} + \gamma_i + \delta_t + \varepsilon_{it} \end{aligned} \tag{2}$$

where *gas delivered* is defined according to Equation 1. We control for in-state production, $\textit{production}_{it}$—which may be subject to influence from the demand-side—to isolate the delivery portion of state i's natural gas supply. To control for state-level unobservables fixed over time, as well as time-specific factors, common across states, we include a full set of state and year fixed effects, γ_i and δ_t, respectively. Unobserved determinants of generation are represented by ε_{it}. Our outcomes of interests examine the share of a state's electricity generation devoted to a certain energy source, f. The coefficient β_1 represents the structural relationship between out-of-state natural gas deliveries and generation shares.

In practice, actual state-to-state delivery shares are unobserved—due to the difficulty in tracking molecules—but also most likely subject to influence by the generating states over time. We proxy for these state-to-state delivery shares using state-to-state pipeline capacities. This approach naturally assumes that capacities strongly correlate with actual delivery quantities. Furthermore, as the evolution of the pipeline infrastructure is most likely endogenous to energy choices, we will fix the state-to-state pipeline links at their pre-Shale Revolution, 1990 levels. Define a single delivery share between states i and j, from delivery share matrix $\tilde{\boldsymbol{W}}$, as $\tilde{w}_{ij}$, according to Equation 6. We form the following delivery proxy for Equation 2.

$$\textit{predicted deliveries}_{it} = \tilde{\boldsymbol{W}}_i \cdot \mathbf{Q}_t = \sum_{j \in N} \tilde{w}_{ij} \times \textit{production}_{jt} \tag{3}$$

Given this setup, with a pre-defined pipeline network, our method is a generalized difference-in-differences approach with multiple treatments. That is, for producing state j, $\tilde{w}_{ij}$ defines the extent to which j's production "treats" state i. Our approach, therefore, restricts the marginal treatment influence of each producing state to be proportional to the instrumented extent of treatment, $\tilde{w}_{ij}$. That is, from Equation 2, in the reduced-form, the marginal effect of j's production on i's energy choices is defined by $\beta_1 \cdot \tilde{w}_{ij}$.

This approach takes the pre-existing network as given and assumes that out-of-state production is exogenous. One may be concerned, however, that some states have considerable influence on other states' production. If this were the case, our estimates would be biased; for example, if state i's energy choices drive production in some other state, j. To mitigate these concerns, we construct an additional proxy for deliveries which leverages out-of-state geological variation, and only makes use of aggregate production levels. This is similar to a Bartik instrument (Bartik, 1991), commonly used in the literature on labor markets. Define our second proxy for deliveries as the following.

$$shale\ exposure_{it} = production_t \cdot \sum_{j \in N} \tilde{w}_{ij} \times shale_j \tag{4}$$

where $shale_j$ denotes the square mileage of shale in state j—a proxy for production potential—and $production_t$ is national-level production at time t.[9]

Because our two proxies for deliveries are measured with error (primarily, in the case of Equation 3) and on different scales (primarily, in the case of Equation 4), we scale our estimates to actual deliveries by two-stage least squares. As time-varying state-to-state delivery shares (as in Equation 1) are not directly observable to us, we scale our estimates using aggregate delivery shares. Doing so creates a straight-forward representation of the causal effect of aggregate gas production.

To illustrate, define an alternative construct of our measure of gas deliveries from Equation 1 as the product of state-level, time-varying, receipt shares and national-level production. That is,[10]

9 That is, $production_t = \sum_{j \in N} production_{jt}$.

10 As we observe receipt shares as a proportion of gas production used for electricity generation, our measure will naturally sum to one across states—i.e., $\sum_{i \in N} receipt\ share_{it} = 1$ for all t—whereas actual receipt shares for electricity sum to the overall proportion of national production used for electricity, denote as ω^e. This implies that the true amount of natural gas delivered for electricity is equal to $\omega^e_t \times receipt\ share_{it} \times production_t$. Given that this distinction only scales our calculations over time we do not expect it to alter our estimates of interest. That is, from Equation 2, we estimate the parameter $\tilde{\beta} = \beta \times E(\omega^e)$, and interpret the state-specific effect of deliveries as $\tilde{\beta} \times receipt\ share_i = \beta \times E(\omega^e) \times receipt\ share_i$, and the average effect as its mean.

$$gas\ delivered_{it} = receipt\ share_{it} \times production_t$$

Using our proxies for gas deliveries, we estimate the following first stage:

$$gas\ delivered_{it} = \tilde{\beta}_1 \cdot \binom{predicted\ deliveries}{\substack{or \\ shale\ exposure}}_{it} + \tilde{\beta}_2 \cdot production_{it} + \tilde{\gamma}_i + \tilde{\delta}_t + \tilde{\varepsilon}_{it} \tag{5}$$

Our instrumental variable design now allows us to estimate the average causal effect of national-level production on state energy choices. Given our two-stage least squares estimates from Equation 2, we calculate the marginal effect of national production using our estimate of $\beta_1 \cdot receipt\ share_{it}$ and the average treatment effect as its mean. In all results, we cluster our standard errors at the state-level. Furthermore, throughout, we weight observations by total generation (Solon, Haider, and Wooldridge, 2015) so that a megawatt of generation is treated equally among all states, rather than under-emphasizing states with overall much higher levels of generation.

As the objective of this paper is to identify the counterfactual path of energy choices in the electricity sector, in absence of the national Shale Revolution, cross-price elasticities between natural gas prices and alternative energy choices are of secondary importance. Furthermore, estimating a structural analogue to Equation 2, which replaces deliveries with natural gas prices, may produce biased estimates due to other infrastructure spending related to the state energy choices. For example, in adding additional natural gas-fired capacity to the grid, a plant operator may need to expand pipeline capacity. As we identify off of the interaction between natural gas production and the pre-defined pipeline network, our instrument might not only relate to natural gas prices, but also these infrastructure investments, thereby invalidating the exclusion restriction. For these reasons, we directly interpret Equation 2 as the equation of interest. In section 7, we examine some potential mechanisms driving the observed effects of the Shale Revolution. This includes examining the relationships with respect to natural gas prices.

4 Data

We construct a data set of annual electricity consumption and capacity for the 48 states in the contiguous United States, 1993 to 2016, from the Energy Information Agency (EIA). Data on the electricity consumed in British thermal units (Btus), by fuel type, comes from the EIA State Energy Data System (SEDS), and data on capacity by primary fuel type comes directly from EIA form 860. We construct *generation* $share^f_{it}$ for each fuel type as the percentage of total electricity consumed, in Btus, by the fuel type f within year t in state i according to SEDS. We do this for six different fuel types: natural gas, coal, hydroelectric damns, nuclear, wind, and solar fuel types. The remaining fuel types are aggregated in to a single measure of "other" fuel.

These data are supplemented with data on annual national production of natural gas in billion cubic feet per day (bcf/day), state specific production of natural gas, and the state specific share share of U.S. natural gas deliveries for electric power all from the EIA. These provide us with a measure of $production_t$, $production_{jt}$, and *receipt* $share_{it}$, respectively. Data on average city gate price in real \$/mmBtu comes from the EIA.

We distinguish ourselves empirically by utilizing the interstate natural gas pipeline infrastructure. For each year, we construct an annual state-to-state measure of pipeline capacity for both inflow and outflow. The data come from pipeline level observations in EIA 176 aggregated by origin and destination state. This measure of bilateral pipeline capacity allows us to quantify the share of total outflow from state j that ends up in state i, forming the matrix W_t outlined in section 3. In particular we construct pairwise delivery shares w_{ijt} representing the share of effective capacity, described below, leaving state j that ends up in state i as

$$w_{ijt} = \begin{cases} \frac{EffectiveCapacity_{ijt}}{\sum_{k \neq j} EffectiveCapacity_{kjt}}, & \text{when} \quad i \neq j \\ 0, & \text{when} \quad i = j \end{cases} \tag{6}$$

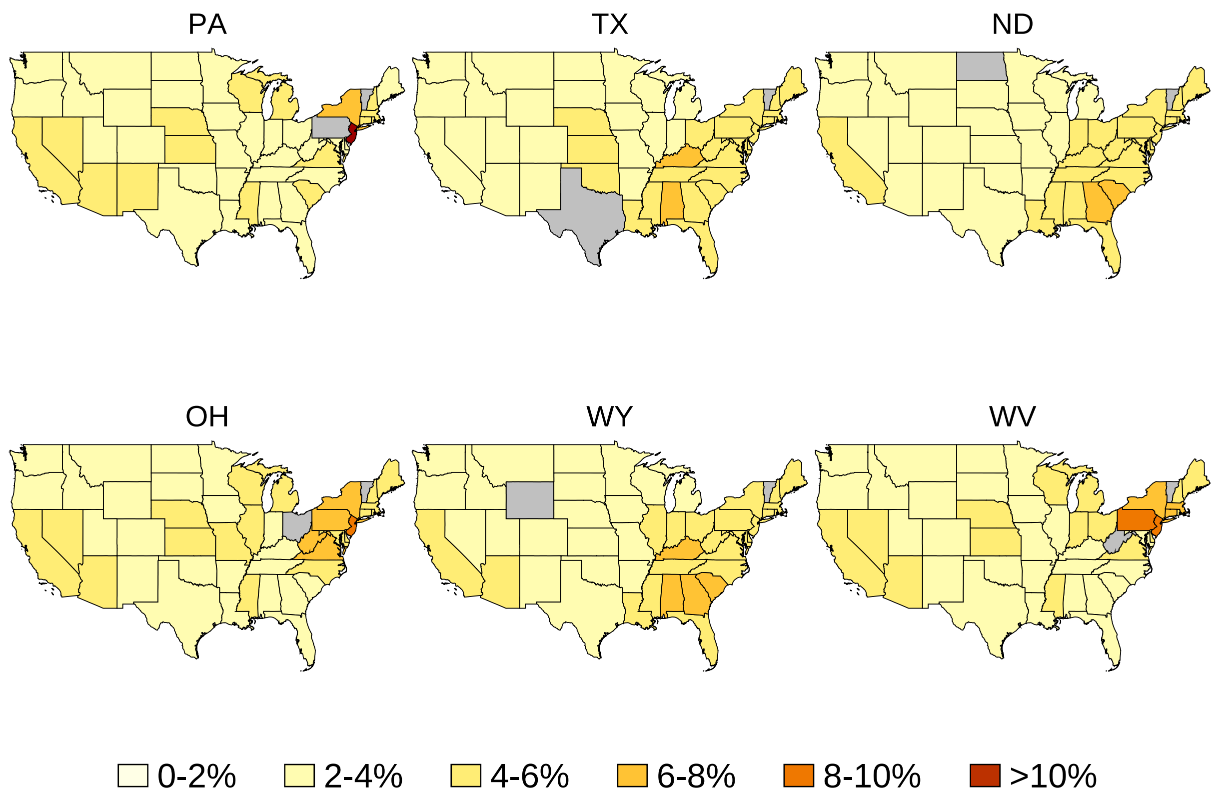
Because gas produced in Pennsylvania might be transported to Virginia, which can then be subsequently transported to Florida, we link all state-to-state pipeline capacities as follows. For each flow from j to i, we consider all states k which receive outflow from i but not j. We then consider the pipeline capacity from j to k as a function of the pipeline capacity from j to i and from i to k. The procedure is repeated iteratively for all states that are linked to k, but not i or j, so that we conceivably quantify how connected production in state j is to all states regardless of how 'down the line' they might be. This is what we refer to as effective capacity. In practice we average pipeline capacities across linkages, however we consider alternatives include minimum capacity and running capacity, as well as limited linkages, all outlined in Appendix A.[11]

As described in section 3, we are primarily interested in the pipeline network from 1990, as it is exogenous to changes in state generation shares after the Shale Revolution and can

[11] Further, one of the robustness checks in appendix B uses historical deliveries, instead of pipeline capacity, as an instrument and finds similar estimates.

be used to determine which states were more impacted by the Shale Revolution. We denote these 1990 shares as $\tilde{W}$. Figure 3 shows choropleths for the distribution of outflow shares for six states for the year 1990. We use these to calculate the two proxies for gas deliveries to each state. The first is the predicted gas deliveries, Equation 3, using $\tilde{W}$ and $production_{jt}$. The second is the exposure to shale formation times national production, Equation 4. Data on the area of potential shale per state comes from the EIA.

Figure 3: Share of Effective Capacity from States with Large Shale Potential.



Note: This map shows the values of $\tilde{w}_{ji}$ for $j \in \{PA, TX, ND, OH, WY, WV\}$. In 1990, Vermont had no pipeline connections to any other state and as a result is omitted from these plots.

Finally, we complete our characterization of the data by calculating carbon emissions associated with electricity generation. To do this we take average emission rates for coal and natural gas based on data from the Energy Information Agency. In particular, we use 53.0 tons of CO_2 per billion Btu of natural gas, and 95.6 tons of CO_2 per billion Btu of coal.[12]

[12] See Pounds of CO2 emitted per million British thermal units (Btu) of energy for various fuels, here: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 The emissions for coal is a weighted average across different coal types.

These ignore CO_2 emissions from petroleum based electricity generation and upstream emissions from the extraction and transportation of coal, natural gas, and petroleum.[13] Although not used in this draft, the impact on local pollutants can be determined using EPA eGRID data.

5 Main Results

5.1 Graphical Evidence

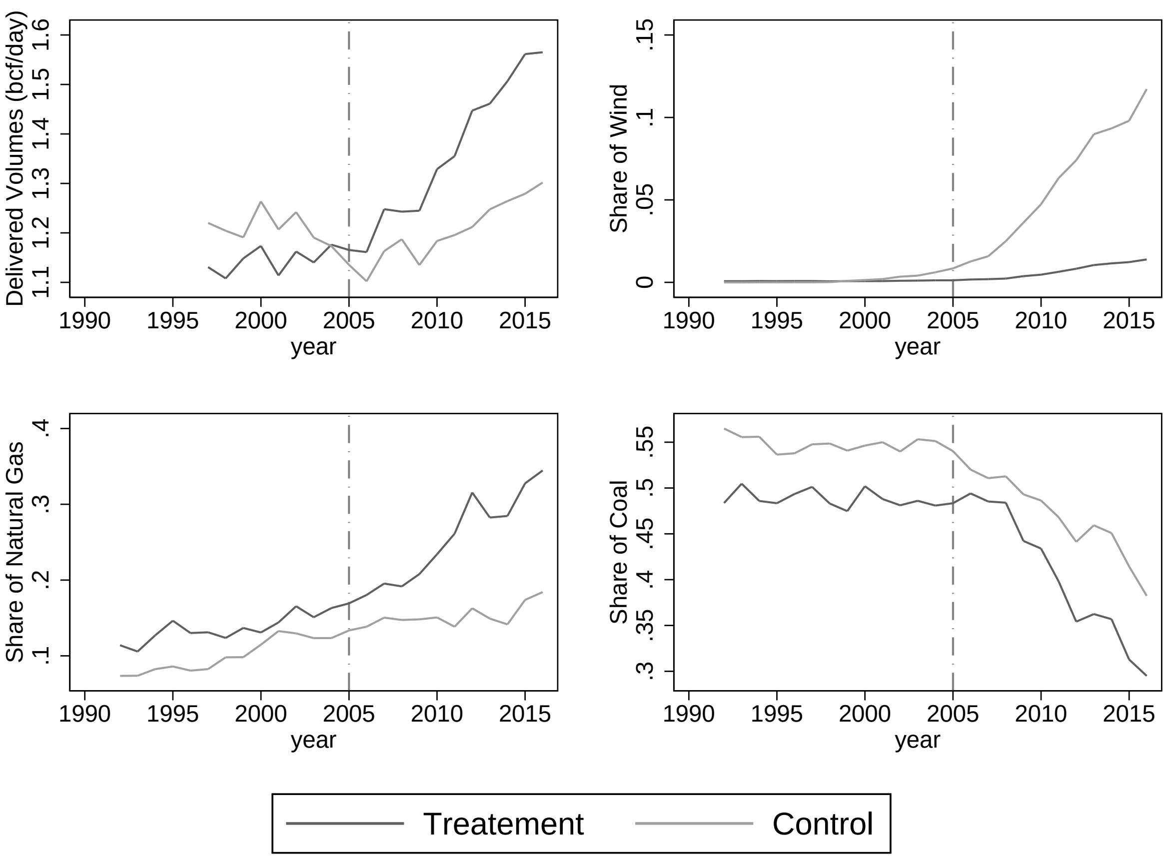
Our empirical strategy is analogous to a generalized difference-in-differences framework, where our event, the Shale Revolution, is not a discrete treatment in time, but rather, a continuous development. We exploit both the timing of production, paired with the interconnections of the pipeline network, in order to estimate the causal impacts on generation sources. To this extent, our identification strategy assumes that, absent the production boom, states more connected to producing states would have exhibited patterns in energy choices over time proportional to states less connected to producing states. In this section, we present evidence in favor of this assumption by examining the relationship between national gas production and this treatment intensity.

Treatment intensity level is best expressed using our measure of shale exposure, defined in Equation 4. In Figure 4, we split our sample for various outcomes between below (control) and above (treatment) median shale exposure. Our strategy assumes that natural gas production is the only factor driving the time-varying differences between these two groups. Therefore, prior to the boom, we should expect relatively fixed differences between the two groups over time. In Panel A, we illustrate this relationship for actual gas deliveries. In Panels B, C, and D, we demonstrate the consistency of these relationships for shares of generation devoted to wind, coal, and natural gas energy, respectively. As is visible from these graphs, the differences are relatively stable prior to the boom (beginning around 2006), and begin to diverge following this surge in production.

To express these relationships more clearly, in Figure 5, we plot the differences in deliveries (Panel A) and generation shares (Panel B-D) for the treatment and control states against production. In contrast to a general difference-in-differences framework with a discrete treatment in time, natural gas production increases gradually, beginning around 2006. Consistent with our identifying assumption, we observe this gradual divergence between treatment and control states which appears to track production growth well.

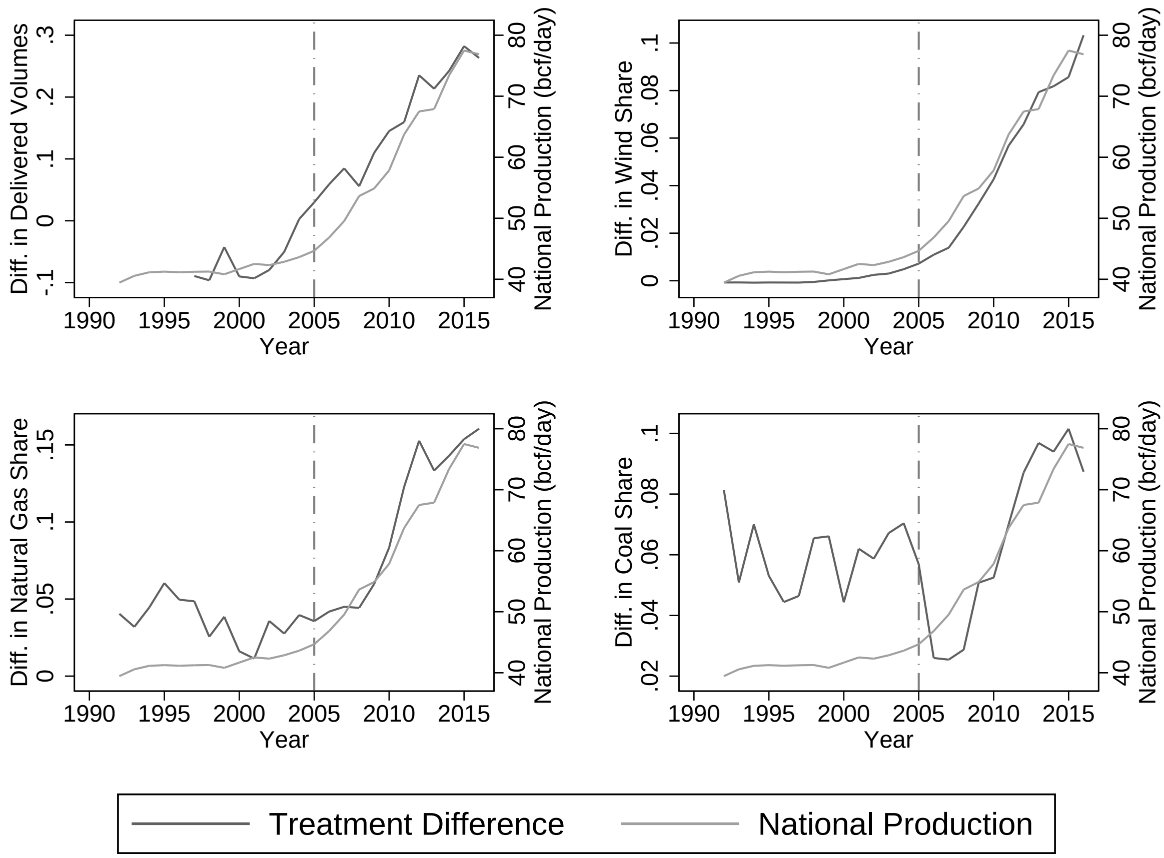
[13] Coal and Natural Gas represent 99% of all CO_2 emissions from the electric power sector in 2017 according to the EIA. Information on upstream emissions is limited.

Figure 4: Treatment Intensity from the Shale Revolution



Note: Above splits the outcome variables in to a "treatment" group, defined as state with above median shale exposure (from Equation 4), and a "control" group, defined by below median shale exposure.

Figure 5: Treatment Intensity versus Production



Note: Treatment is the same as Figure 5. The "treatment difference" in delivered volumes and natural gas share is (Treatment−Control), the difference in wind share and coal share is (Control−Treatment). This is done so that the difference in trends can more easily be compared to national production.

5.2 Effect on Total Generation

Before we present our main empirical results, we first test whether the shale revolution had an impact on quantity of electricity demanded in a state. The results that follow look at the proportion of electricity generation coming from alternative energy sources, and so depends on total electricity generated. We do this because generation shares is an intuitive manner in which to present our results. If the Shale Revolution impacted total generation in a state, our results would in part be determined by the denominator in fuel shares, creating a different interpretation. To address this we directly test whether the Shale Revolution had a significant effect on total electricity generation.

In Table 1, we present our estimates for the impact of the Shale Revolution on total generation. The first two columns present the standard OLS estimates on endogenous gas receipts, each with a full set of state and year fixed effects, with (Column 1) and without (Column 2) controlling for own-state production. Our two-stage least squares estimates are presented in Columns 3 through 6. Columns 3 and 4 are estimated using our predicted gas deliveries instrument from Equation 3, while Columns 5 and 6 use shale exposure from Equation 4.

Table 1: Exposure to Shale Revolution Impact on Generation Shares.

	1	2	3	4	5	6
	Total Generation in Trillion Btu [mean=775.84]					
$ReceiptShare_{it} \cdot NationalProduction_t$	2.49	0.62	-27.88	-9.58	-44.09	-37.01
	(26.87)	(25.67)	(49.98)	(36.95)	(45.24)	(37.90)
mean $s_{it} \cdot NationalProduction_t$	1.07					
mean $NationalProduction_t$	51.45					
Observations	1152	1152	1152	1152	1152	1152
State FE	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y
Own State Production	N	Y	N	Y	N	Y
Instrument	N/A		Predicted Gas		Shale Exposure	
1st Stage F-statistic			10.43	10.79	13.59	14.45

Notes: Balanced panel of lower 48 states from 1993 to 2016. Total electricity generation is the outcome. The mean of all relevant variables are presented in brackets. Standard errors, clustered at the state level, are in parenthesis.

Instrumenting for endogenous natural gas deliveries switches the sign of our estimates from positive to negative. However, in all specifications, the estimated effects on generation are statistically and economically insignificant. Though relatively noisy, we see these insignificant estimates as evidence that the Shale Revolution had little to no impact on total generation. In the results to follow, we will, therefore, interpret any effect on generation shares as predominantly impacting the numerator of generation for that specific energy source, rather than the denominator of total generation.

5.3 Reduced Form Results

We now evaluate how an increase in predicted natural gas deliveries or exposure to shale rock, based off of the 1990 interstate pipeline infrastructure, impacts the share of electricity generated by different fuel types. The explanatory variable, $\textit{predicted deliveres}_{it}$ or $\textit{shale exposure}_{it}$, represents the quasi-random exposure of each state to the the Shale Revolution. With these regressions we are presenting the relationship between our proxy for treatment of the

Table 2 presents the results in six separate panels corresponding to six different fuel types. Controlling for time-invariant state specific effects, state-invariant time specific effects, and own state production of natural gas (column 2 of Table 2), we see an increase in natural gas deliveries or shale exposure is associated with a statistically significant increase in the share of electricity generated from natural gas, and a decrease in the share of electricity generated from wind turbines and coal plants. Namely, a unit increase in predicted gas deliveries in bcf/day according to the 1990 interstate natural gas pipelines increases the share of electricity generated from natural gas by 14.1 percentage points, while reducing the share of electricity generated by coal by 6.6 percentage points, and reducing the share of electricity generated by wind by 8.6 percentage points. We see these values attenuated slightly once we include region-by-year fixed effects (column 3 Table 2).[14] Although the units for Shale Exposure are different, the relative magnitudes are similar (columns 4 to 6 Table 2).

The reduction in generation share of both coal and wind turbines approximately equals the increase in generation share from natural gas for both proxies of exposure to the Shale Revolution. This suggest there is a substitution of natural gas based generation for wind turbine and coal based generation based on our measure of exposure to the Shale Revolution. At the mean value of predicted natural gas deliveries, column 2 suggests a ten percent increase in predicted natural gas deliveries at the mean will decrease coal share by 0.66% and wind by 0.96%. As the average share of coal generation in 48% and the average share of wind is only 1.6%, the relative effect on wind is much larger than the relative effect on coal.

The point estimates for the remaining fuel types, solar and hydro, are statistically and economically insignificant in the preferred specifications, columns 2 and 5. The effect on nuclear's fuel share remains statistically significant in column 5, however the estimate becomes

[14] We consider six regions, with the number of states per region in parenthesis: Central (12), Midwest (6), Northeast (13), Southeast (6), Southwest (6), Western (6).

statistically insignificant and negative with the inclusion of region-year fixed effects.[15]

[15] The results in columns 2 and 5 are primarily driven by the states Vermont and New Jersey. Both of these states had relatively less predicted natural gas deliveries (and shale exposure) and less generation from nuclear power plants towards the end of the sample period.

Table 2: Exposure to Shale Revolution Impact on Generation Shares.

	1	2	3	4	5	6
Panel A:	Nat. Gas Generation Share [mean=16.03]					
Predicted Natural Gas Deliveries	14.52	14.02	6.92			
[mean=1.03]	(5.22)	(4.85)	(5.43)			
Shale Exposure				10.61	10.21	5.11
[mean=1.87]				(3.36)	(3.09)	(4.22)
Panel B:	Coal Generation Share [mean=47.94]					
Predicted Natural Gas Deliveries	-6.09	-6.57	-2.17			
[mean=1.03]	(3.39)	(3.55)	(3.13)			
Shale Exposure				-4.62	-4.70	-1.24
[mean=1.87]				(2.37)	(2.36)	(2.35)
Panel C:	Wind Generation Share [mean=1.64]					
Predicted Natural Gas Deliveries	-8.56	-8.51	-4.52			
[mean=1.03]	(2.25)	(2.35)	(1.98)			
Shale Exposure				-6.86	-6.73	-3.99
[mean=1.87]				(1.57)	(1.55)	(1.42)
Panel D:	Solar Generation Share [mean=0.09]					
Predicted Natural Gas Deliveries	0.62	0.49	1.24			
[mean=1.03]	(0.49)	(0.42)	(0.77)			
Shale Exposure				0.33	0.27	0.96
[mean=1.87]				(0.30)	(0.26)	(0.58)
Panel E:	Hydro Generation Share [mean=10.45]					
Predicted Natural Gas Deliveries	1.52	2.19	1.10			
[mean=1.03]	(1.35)	(1.36)	(1.32)			
Shale Exposure				1.36	1.58	1.10
[mean=1.87]				(1.13)	(1.05)	(1.18)
Panel F:	Nuclear Generation Share [mean=18.71]					
Predicted Natural Gas Deliveries	2.17	2.55	-1.53			
[mean=1.03]	(1.75)	(1.78)	(2.37)			
Shale Exposure				2.34	2.46	-0.82
[mean=1.87]				(1.14)	(1.10)	(1.84)
Observations	1152	1152	1152	1152	1152	1152
Own State Production	N	Y	Y	N	Y	Y
State FE	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	N	Y	Y	N
Region-Year FE	N	N	Y	N	N	Y

Notes: Balanced panel of lower 48 states from 1993 to 2016. Each panel corresponds to different fuel generation shares as the dependent variable, in percentage points. The mean of all relevant variables are presented in brackets. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year.

5.4 Effect of Gas Deliveries and National Production

In this section, we take advantages of the 1990 pipeline infrastructure to identify the effects of national production and state natural gas deliveries on the fuel specific generation shares. We estimate coefficients β_1 in Equation 2 using two stage least squares with Equation 5 as the first stage. We assume that quantity of effective out of state production, or production potential, as defined by the legacy pipeline network influences fuel generation shares only through actual natural gas deliveries (or delivery shares). As a result, these instruments address the endogeneity between natural gas deliveries (or deliver shares) and fuel generation shares.

With this regression we are able to make inference in two ways. First, we can directly interpret the estimate of β_1 as the effect of more natural gas deliveries, as explained by the Shale Revolution and the legacy pipeline, on average fuel generation shares. Further, we assume the extent to which national production impacts fuel generation share is directly proportional to the share of natural gas deliveries for electricity consumption going to each state, $receipt\ share_{it}$. This implies we can interpret the effect of national production on fuel generation shares by averaging the estimate of β_1 over $receipt\ share_{it}$.

Table 3 presents the results. Columns 1 and 2 are estimated using OLS, columns 3 to 5 use $predicted\ gas_{it}$ as an instrument, and columns 6 and 8 use $shale\ exposure_{it}$ as an instrument. We see that both instruments lead to quantitatively similar results. Looking at our preferred specification, Column 7, we see that a one unit increase in state natural gas deliveries in bcf/day is associated with an increase in the share of electricity generated from natural gas by 8.2 percentage points, a decrease in the coal generation share of 3.8 percentage points, and a decrease in wind generation share of 5.4 percentage points. Inclusion of Region-Year fixed effects, columns 5 and 8, provides quantitatively similar estimates, albeit under powered with state-clustered standard errors.

The bottom of the table shows the average quantity of gas deliveries, as well as the average value of national production. With an average of 1.07 bcf/day deliveries per state year, a ten percent increase in the average natural gas deliveries will increase natural gas generation share by 0.8%, decrease coal generation share by 0.4% and decrease wind generation share by 0.5%. We see the first stage F-statistic at the bottom of Table 3 for both instruments is above 10, suggesting they are good predictors of natural gas deliveries and are not subject to weak instrument critique.

Table 3: Impact of National Production on Generation Shares.

	1	2	3	4	5	6	7	8
Panel A:	Nat. Gas Generation Share [mean=16.03]							
$ReceiptShare_{it} \cdot NationalProduction_t$	5.00	5.45	8.68	8.09	8.91	8.48	8.19	7.83
	(0.92)	(0.56)	(1.17)	(1.20)	(4.13)	(1.34)	(1.23)	(4.07)
Panel B:	Coal Generation Share [mean=47.94]							
$ReceiptShare_{it} \cdot NationalProduction_t$	-1.81	-1.32	-3.64	-3.79	-2.79	-3.69	-3.77	-1.90
	(0.68)	(0.93)	(1.40)	(1.39)	(3.26)	(1.28)	(1.30)	(2.99)
Panel C:	Wind Generation Share [mean=1.64]							
$ReceiptShare_{it} \cdot NationalProduction_t$	-1.01	-0.32	-5.12	-4.91	-5.81	-5.48	-5.39	-6.10
	(0.24)	(0.18)	(1.52)	(1.47)	(3.25)	(1.53)	(1.57)	(3.33)
Panel D:	Solar Generation Share [mean=0.09]							
$ReceiptShare_{it} \cdot NationalProduction_t$	-0.07	-0.02	0.37	0.28	1.60	0.27	0.22	1.47
	(0.06)	(0.03)	(0.31)	(0.25)	(1.48)	(0.26)	(0.22)	(1.38)
Panel E:	Hydro Generation Share [mean=10.45]							
$ReceiptShare_{it} \cdot NationalProduction_t$	-0.19	-0.18	0.91	1.26	1.42	1.08	1.26	1.68
	(0.22)	(0.18)	(0.93)	(0.91)	(1.85)	(1.02)	(0.99)	(2.02)
Panel F:	Nuclear Generation Share [mean=18.71]							
$ReceiptShare_{it} \cdot NationalProduction_t$	-0.37	-1.30	1.29	1.47	-1.97	1.87	1.97	-1.25
	(0.28)	(0.39)	(1.12)	(1.04)	(3.14)	(1.09)	(1.07)	(2.84)
mean $s_{it} \cdot NationalProduction_t$	1.07							
mean $NationalProduction_t$	51.45							
Observations	1152	1152	1152	1152	1152	1152	1152	1152
Own State Production	Y	Y	N	Y	Y	N	Y	Y
State FE	Y	Y	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	N	Y	Y	N
Region-Year FE	N	Y	N	N	Y	N	N	Y
Instrument	N/A		Predicted Gas			Shale Exposure		
1st Stage F-statistic			10.43	10.79	10.32	13.59	14.45	8.97

Notes: Each panel corresponds to different fuel generation shares as the dependent variable, in percentage points. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year.

We calculate the average marginal effect of national production with the estimate of $\hat{\beta}^f$ presented in Table 3, as the average weighted across states by their total electricity generation, Btu_{it}, as a fraction of all electricity generated in that year Btu_t:

$$AME^f = \sum_{t=1993}^{2016} \sum_i \frac{Btu_{it}}{Btu_t} \cdot receipt\ share_{it} \cdot \hat{\beta}_1^f$$

Columns 1 and 2 of Table 4 use the estimates from columns 4 and 7 of Table 3. We see that an increase in national production of one additional bcf/day results in an increase in natural gas generation share of 0.4 percentage points, and a decrease in the generation share of coal and wind of 0.2 and 0.25 respectively. As the Shale Revolution has been associated with an increase in national production of approximately 30 bcf/day, as shown in Figure 2, this suggests an effect on generation shares of over 5 percentage points for each fuel type.

To separate between long run and short run factors determining the fuel mix, columns 3 and 4 of Table 4 show the same marginal effects, estimated from Equation 2, however controlling for the nameplate capacity, in MW, of the corresponding fuel type. By taking into account the capacity of the fuel type within the state, we are only looking at the short run displacement of fuels. We see the effect of national production on natural gas and coal generation remain, while the effect on wind generation share disappears. This is consistent with section 2; in the short-run we expect natural gas to displace coal generation in the merit order, but to have no effect on wind generation because wind generation can not be dispatched.

To quantify the effect of natural gas production on the long run fuel mix we look directly at the share of total generation capacity corresponding to each fuel type within a state-year, as shown in columns 5 and 6. The effect on coal generation is now dissipated, coal nameplate-capacity share within a state is not changing significantly in response to more national production of natural gas, even if the unit operating less frequently.

We do see a sizable effect of more natural gas production on the share of generation capacity dedicated to natural gas (as shown by Brehm (2019)), but also wind turbines. The average marginal effect of national production on wind capacity share is similar in magnitude to that of wind generation share, suggesting all of the impact of national natural gas production on wind generation share is from long run changes in capacity. This could be because long run purchasing power agreements are harder to secure in states that have consistent access to natural gas at a low price thanks to the Shale Revolution.

Appendix B presents results from the first stage regression and walks through some robustness checks. We show the results are robust to sample selection of only states with wind turbine potential, and to alternative measurements of pipeline linkages, and an alternative instrument based on historic natural gas deliveries.

Table 4: Average Marginal Effect of National Production

	1	2	3	4	5	6
Panel A: Nat. Gas	Generation Share				Capacity Share	
Average Marginal Effect	4.04	4.09	4.69	5.06	4.41	4.83
	(0.60)	(0.62)	(1.80)	(2.24)	(0.85)	(0.67)
Panel B: Coal	Generation Share				Capacity Share	
Average Marginal Effect	-1.90	-1.88	-1.77	-1.77	-0.37	-0.33
	(0.69)	(0.65)	(0.62)	(0.61)	(1.15)	(1.28)
Panel C: Wind	Generation Share				Capacity Share	
Average Marginal Effect	-2.46	-2.70	-0.03	-0.28	-3.25	-3.46
	(0.74)	(0.79)	(0.29)	(0.35)	(0.98)	(1.07)
Panel D: Solar	Generation Share				Capacity Share	
Average Marginal Effect	0.14	0.11	-0.01	-0.01	0.22	0.18
	(0.13)	(0.11)	(0.06)	(0.05)	(0.18)	(0.16)
Panel E: Hydro	Generation Share				Capacity Share	
Average Marginal Effect	0.63	0.63	-0.11	-0.12	1.21	1.23
	(0.46)	(0.50)	(0.14)	(0.17)	(0.76)	(0.79)
Panel F: Nuclear	Generation Share				Capacity Share	
Average Marginal Effect	0.74	0.99	0.83	1.12	-0.36	-0.48
	(0.52)	(0.54)	(0.53)	(0.53)	(0.50)	(0.48)
Instrument	PG	SE	PG	SE	PG	SE
Capacity Control	N	N	Y	Y	N	N

Notes: The average marginal effect of 10bcf/day of national production across all states on generation share (in columns 1-4) and capacity share (columns 5 and 6) in percentage points.

6 Counterfactual Fuel Mix and Carbon Emissions

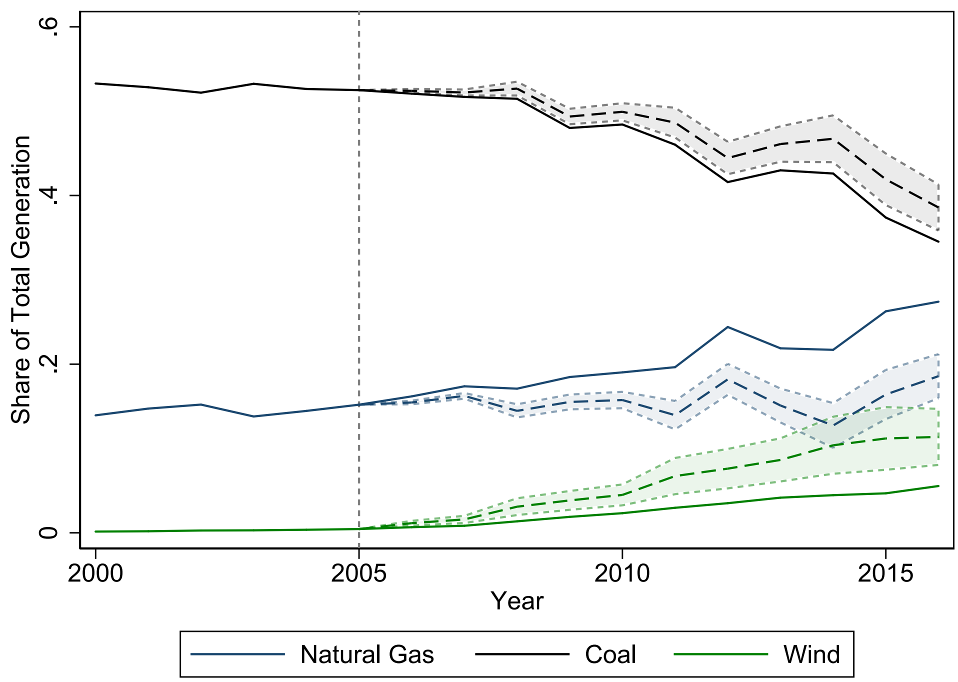
We use our preferred estimates of the effect natural gas deliveries on generation shares, column 7 of Table 3, to quantify the counterfactual fuel mix as if the Shale Revolution had never happened. We calculate this counterfactual by taking the observed state-year generation shares for each fuel type, and subtracting the change in that fuel generation shares that can be explained by the changes in natural gas deliveries from 2005:

$$counterfactual_{it}^{f} = generation\ share_{it}^{f} + \hat{\beta}_1^{f} \cdot (gas\ delivered_{i2005} - gas\ delivered_{it}) \tag{7}$$

we do this for all fuel types Natural Gas, Coal, Nuclear, Wind, Solar, Hydro, and Other. As a result of this procedure we have the state specific share of electricity generated by each fuel type, for all sample years, that cannot be explained by the change in natural gas deliveries since 2005. What remains in our counterfactual is the share of electricity determined by national trends, state averages, in state natural gas production, and an idiosyncratic error.[16]

Our counterfactual is only evaluating fuel switching that isn't explained by changes in national production of natural gas. To find the national fuel mix, we average the counterfactual state-year generation shares across the contiguous 48 states in a year, with weights given to the total electricity generated in the state. Figure 6 presents the counterfactual share of total generation for wind, natural gas, and coal for years after 2005. The shaded area represents a 95% confidence interval.

Figure 6: Counterfactual Energy Mix



Note: Counterfactual fuel mix based off of the structural estimates in Table 3, column 6. Dashed lines represent point estimates and the shaded area is the 95% confidence interval with state clustered standard errors.

Although the observed share of electricity generated from natural gas increases from 2005, our counterfactual shows that the share of electricity from natural gas would have

[16] Substituting Equation 2 in $counterfactual_{it}^{f}$ shows that

$$counterfactual_{it}^{f} = \hat{\beta}_1^f gas\ delivered_{i2005} + \beta_2 production + \gamma_i + \delta_t + \varepsilon_{it} + \left(\beta_1^f - \hat{\beta}_1^f\right) gas\ delivered_{it}$$

so in expectation the counter factual is the average generation share explained by 2005 natural gas deliveries, in state production, state and year averages so long as $\hat{\beta}_1^f$ is an unbiased estimate for β_1^f.

remained the same absence of the Shale Revolution. The share of electricity generated from coal, relative to 2005, declines in both our counterfactual and in the observed data, however we see less of a decline in our counterfactual. This suggests the share of electricity generated from coal would have declined, albeit not by as much, even in the absence of the Shale Revolution, and that the Shale Revolution cannot completely explain the decline in coal's generation share from 2005.

Factors that could be contributing to the decline of coal's generation share in the absence of the Shale Revolution include inevitable retirements due to the age of plant, and environmental regulations such as the Mercury and Air Toxics Standards (MATS). First considering natural retirements, a majority of the coal plants in the United States were built between 1960 and 1980. At the beginning of the Shale Revolution these plant would be 25 to 45 years old. If the plant was built by a regulated utility that expected a 30-year life of the plant, it is possible that the asset has fully depreciated at the beginning of the Shale Revolution. Because it is depreciated, the plant will not count towards the utility's rate base and as a result will not provide the utility with a positive return.

Otherwise, MATS was a regulation finalized by the U.S. Environmental Protection Agency in 2011, having an impact on all Coal power plants over 25 Megawatts. All existing generating units had four years to comply with the regulation, however compliance by some generators began immediately. Compliance cost increased the cost of production, which might have led to more coal plants producing electricity less often. Further, a fair number of coal plants decided to stop operating, or switch to natural gas as a fuel after the implementation of MATS, reducing the overall share of electricity generated from coal.

We see that renewable generation, namely electricity generated from wind turbines, increases in our counterfactual. In 2016, about 5.6% of all electricity was generated from wind turbines. Our counterfactual suggests this would be between 8 and 11.4% percent if natural gas production and deliveries remained at their 2005 levels.[17] We argue this is because the increased availability of natural gas, at a lower market price, made investments in wind turbines less attractive compared to new natural gas plants. Further, as we show later, there is some evidence that states with more access to natural gas from the Shale Revolution were less likely to pass Renewable Portfolio Standards encouraging the development of wind turbines and solar panels.

The implications for CO_2 aren't apparent from Figure 6, as our estimates suggest there would be more coal generation (increasing CO_2) and more wind generation (decreasing CO_2)

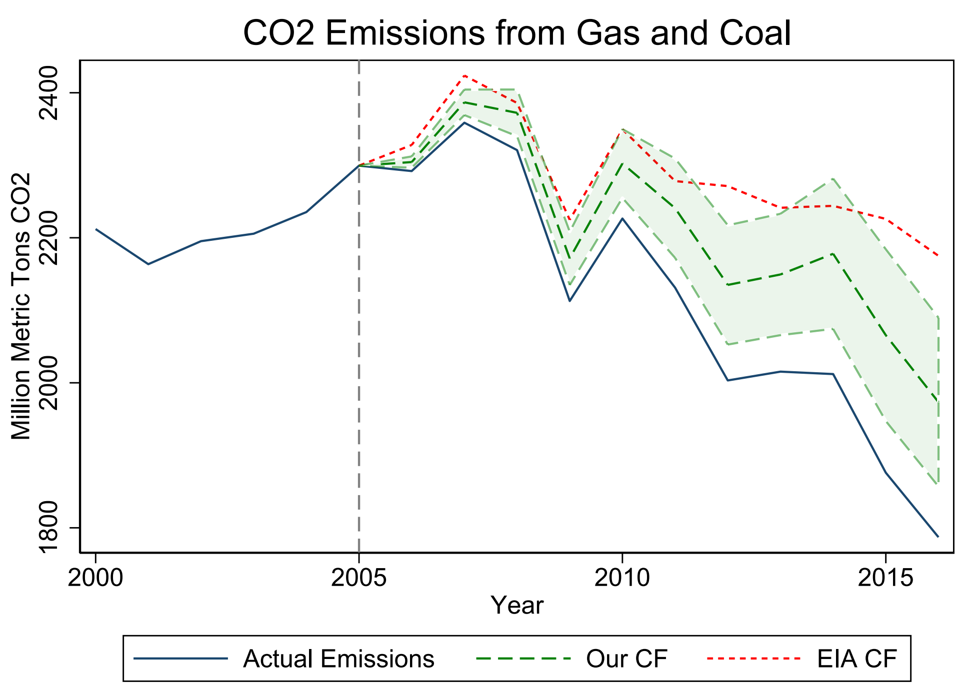
[17] While we do not show it here, total renewable generation in the same year is between 12 and 16% according to our counterfactual. Statistically indistinguishable from the amount of natural gas in our counterfactual. Actual renewable generation in 2016 is 9%.

in the absence of the Shale Revolution. To quantify this we directly estimate the effect of more natural gas deliveries on state level CO_2 emissions similar to Equation 2:

$$CO_2 emissions_{it} = \eta_1 \cdot gas\ delivered_{it} + \eta_2 \cdot production_{it} + \gamma_i + \delta_t + \varepsilon_{it} \tag{8}$$

using *shale exposure* as an instrument for *gas delivered* as in our counterfactual. We find an estimate of η_1 equal to -5.77 million metric tons per 1 bcf/day of natural gas deliveries (with standard error, clustered at the state level, of 1.84). This estimate implies more natural gas deliveries reduces state-level CO_2 emissions from coal and natural gas on average. Figure 7 uses a similar method to Equation 7 to present the counterfactual CO_2 emissions from the electric power sector in the United States, labeled "Our CF", assuming natural gas production remained at its 2005 level.

Figure 7: Counterfactual CO2 Emissions



Note: Counterfactual emissions come from the estimates of the parameters in Equation 8 using a method similar to Equation 7. Dashed lines represent point estimates and the dotted lines is the 95% confidence interval with state clustered standard errors.

We see there are more CO_2 emissions in the counterfactual relative to the realized CO_2 emissions in the United States, labeled "Actual Emissions." This is the emissions benefit of the Shale Revolution. CO_2 emissions are reduced as less carbon intensive natural gas replaces more carbon intensive coal. It is hard to compare our estimates to existing studies because they look at the effect of natural gas prices, not production, on CO_2 emissions. One exception is Brehm (2019), who presents a counter factual for 2013 that is very similar to ours.

In the same diagram, we present the change in CO_2 emissions "attributable to coal-to-gas switching" by the Energy Information Agency from EIA (2018) as "EIA CF."[18] These numbers are often cited by industry and government agencies as the benefits of hydraulic fracturing (through natural gas prices) in reducing CO_2 emissions. For example, Adam Sieminski, former administer of the EIA, stated "The drop in CO_2 emissions is largely the result of low natural gas prices, which have contributed to natural gas displacing a large amount of coal used for electricity generation."[19] Their counterfactual represents what the total carbon dioxide emissions would be if not for the switch to natural gas, as implied by the Shale Revolution.

According to the EIA estimates carbon emissions would not have changed much from 2005 had it not been for coal-to-gas switching. Implying there are major benefits from hydraulic fracturing in the form of carbon emission reductions. In comparison, our counter factual is often statistically different, and smaller, from their estimate. We do see there are environmental benefits of the Shale Revolution in the form of reduced CO_2 from the electric power sector. However, the reduction is not as big as the EIA estimates. This is because some of the "coal-to-gas" switching would have occurred even in the absence of the Shale Revolution because of environmental regulations. Further, as our counterfactual in Figure 6 shows, there would have been more electricity generated from carbon-free resources had the Shale Revolution never happened.

7 Mechanisms and Implications

In this section we discuss some of the mechanisms by which the Shale Revolution impact the electric power sector, and discuss the implication of our results for methane emissions leakage.

7.1 Natural Gas Prices

The main mechanism by which natural gas production impacts the electric power sector is through natural gas prices. In this section we document support for our identification strategy by showing that more natural gas deliveries, as explained through the pre-Shale

[18] In this analysis the EIA calculates the counterfactual emissions in year t using fossil fuel carbon factor (fossil fuel CO_2/fossil fuel generation) from 2005, but the actual fossil fuel generation in year t. In doing this they assume the shale revolution had no effect of fossil fuels share of electricity generated.

[19] *Carbon emissions lowest since '90s thanks to fracking*, Washington Examiner, 8/9/2016.

Revolution pipeline infrastructure, has an impact on natural gas prices. This impact on natural gas prices explains the preference for natural gas as a way to generate electricity relative to coal, wind, or solar.

Table 5 presents our second stage estimates of natural gas production on the natural logarithm of state average city-gate natural gas prices. As in Table 3, columns 1 and 2 are estimated using OLS, columns 3 through 5 use *predicted gas* as an instrument, and columns 6 through 8 use *shale exposure* as an instrument. Our instrumental variable estimates are relatively stable across columns, with the exception of columns 5 and 8, which control for region-by-year fixed effects. Though not statistically different from other instrumental variable specifications, the meaningful change in magnitude and precision is most likely due to a loss in variation, given the similarity in prices within-region.

Our preferred specification, which controls for in-state production, as well as a full set of state and year fixed effects, suggests a significant impact on prices. Our approach estimates the causal effect of a one bcf/day increase in state natural gas deliveries decreases natural gas prices by 11 percent. Scaling by mean deliveries, our estimates show a 1.2 percent decrease in natural gas prices for a 10 percent increase in deliveries.

Table 5: Impact of National Production on Natural Gas Prices.

	1	2	3	4	5	6	7	8
Outcome: Log- Natural Gas Price								
$ReceiptShare_{it} \cdot NationalProduction_t$	-0.01 (0.01)	0.02 (0.01)	-0.10 (0.04)	-0.11 (0.04)	-0.24 (0.16)	-0.10 (0.04)	-0.11 (0.04)	-0.22 (0.15)
mean $s_{it} \cdot NationalProduction_t$					1.07			
mean $NationalProduction_t$					51.45			
Observations	1152	1152	1152	1152	1152	1152	1152	1152
Own State Production	Y	Y	N	Y	Y	N	Y	Y
State FE	Y	Y	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	N	Y	Y	N
Region-Year FE	N	Y	N	N	Y	N	N	Y
Instrument	N/A			Predicted Gas			Shale Exposure	
1st Stage F-statistic			10.43	10.79	10.32	13.59	14.45	8.97

Notes: The outcome is on log- natural gas prices, at the state-level. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year.

We are hesitant to interpret the scaled two-stage least squared estimates of the impact of natural gas prices on generation shares as causal, as it is plausible that the exclusion restriction would not hold in our setting. Our instrument—which leverages interactions between the pre-existing pipeline infrastructure and natural gas production—may partially explain natural gas prices, but also the extent to which a state needs to invest into their pipeline infrastructure in order to switch to more natural gas. In this scenario, these necessary infrastructure investments are an omitted variable that bias our estimates.

If, however, we assume that these are lower order concerns, such that the exclusion restriction approximately holds, then we can scale our estimates in Table 3 by the estimates in Table 5 to calculate the price response with respect to different generation shares. Of particular interest are the estimates for coal and wind—coal producing about a 3.5 percentage point decrease in generation share and wind a 5.5 percentage point decrease in generation share for a 10 percent decrease in natural gas prices. We interpret these estimates to be long-run estimates of the impact of the Shale Revolution, given the nature of the "natural experiment," which involves a long, sustained increase in production, and their corresponding impacts on capacity investments. Evaluating these estimates at 2016 generation share levels produces cross-price elasticities of 1.03 (34 percent share) and 8.5 (6.5 percent share) for coal and wind generation, respectively.

These are relatively high elasticities, particularly for wind generation. This may be due to a couple of factors. First, as our estimates conclude that the primary impact of natural gas production on wind generation is through capacity investments, we can interpret this as a long-run elasticity. Long-run elasticities on capital investments are almost always above one and considerably higher than short-run elasticities. Second, elasticities often exhibit increasing returns at lower quantities. Given the low baseline generation share (6.5 percent) in which we evaluate the elasticity at, a high *relative* impact of natural gas prices is not surprising. Nonetheless, if we take these estimates at face value, our cross-price elasticities highlight the significant role carbon pricing could play in renewable energy investments.

7.2 Renewable Portfolio Standards

Other than natural gas prices, the formation of state policies in response to the Shale Revolution could have had an impact on the share of electricity generated by different fuel types. In particular, more natural gas at a lower market price makes de-carbonizing the electricity sector less expensive (Knittel, Metaxoglou, and Trindade, 2016, p. 251). As a result, states with access to an abundant supply of natural gas, thanks to the Shale Revolution, anticipate their energy mix will become less carbon intensive in the future might not feel the need to address carbon emissions from the electricity power sector. So these states might be less likely to pass a policy supporting renewable generation technologies like a Renewable Portfolio Standard (RPS). With no binding policy to support renewable generation, there will be less deployment of renewable generation resources.

To address this empirically we create a panel data set on all renewable portfolio standards passed in the United States. Because the policies differ in terms of the percent renewable energy mandated, and the deadline when that mandate must be met, we linearly interpolate the RPS for all years between 1992 and 2017. For example, if the RPS is passed in 2010 to achieve a 10% renewable mandate by 2015, the effective percent of electricity mandated is 2% in 2011, 4% in 2012, 6% in 2013, and so on. This captures how the renewable portfolio standard becomes more binding over time.[20]

With first show how the cross sectional difference in % mandated renewables, from 2005 to 2015, is correlated *shale exposure* (defined inEquation 4). The left panel of Figure 8 shows a moderate correlation between these two, with a few outliers, suggesting that those states that were most exposed to the Shale Revolution after 2005 were less likely to enact more stringent RPS standards between 2005 and 2015. In the right panel we show how the interploated % renewable energy mandated by state RPSs changes over time between the states with above, and below, median *shale exposure*. We see after the occurrence of the shale revolution, the average % mandated in the control states (with lower *shale exposure*) is higher than the average % mandated in the treatment states (with higher *shale exposure*).

7.3 The Benefits *and* Costs of Shale Gas Production

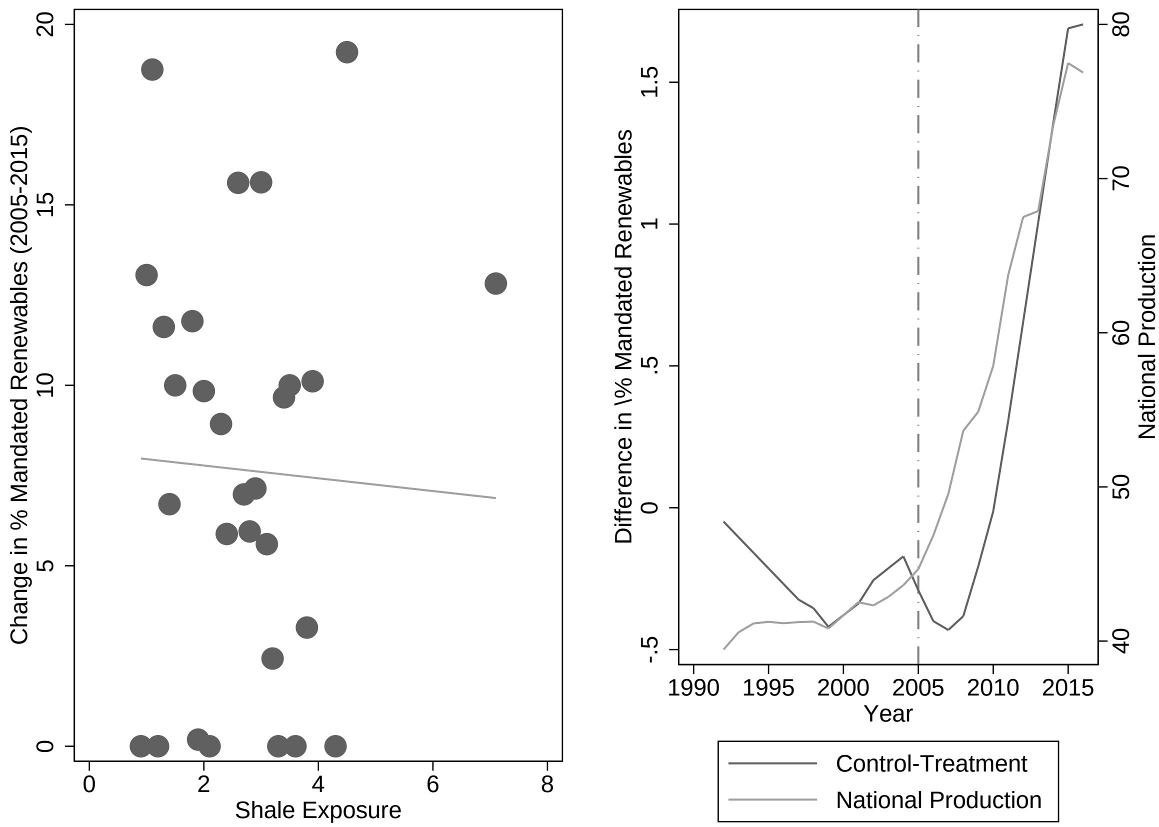
There has been significant conjecture of a nation-wide hydraulic fracturing ban in recent years. Some states have already banned it: New York and Vermont in 2012, Maryland in 2017, and most recently, Washington in May of 2019. Other states have pushed to strengthen regulations around "fracking"—for example, Colorado recently failing to pass Proposition 112 which would lengthen the distance between new oil and gas development and vulnerable areas, such as homes and schools, to 2,500 feet. Those opposed to bans have often asserted the large reductions in greenhouse gases made possible through expanded shale development.

Though our results support the notion that the Shale Revolution has led to a significant reduction in greenhouse gas emissions, we have shown evidence that this effect has been modest, and significantly less than other estimates. Our results suggest that external factors, such as aggressive regulation on coal-fired generation (e.g., EPA's Mercury and Air Toxics Standards), would have led to significant reductions in carbon emissions, even in absence of the increase in natural gas production.

Though we should not discount the environmental benefits of new access to affordable shale gas, one should also take into account the marginal cost of natural gas production. The benefits of the Shale Revolution could easily be canceled out from leaks during the production and transportation process because methane—the main component of natural

[20] If the policy enacted has multiple target dates, like one in 2010 and another in 2030, we interpolate separately for each one.

Figure 8: Relationship between RPS Requirements and Shale Exposure



Note: The left panel shows the scatter plot and line of best fit between Shale Exposure and the Change in the Interpolated % of Electricity Mandated from Renewables from 2005 to 2015. The right panel shows difference between the average % of renewables mandated for treatment states and controls states, where treatment is defined as above median value of shale exposure (as in Figure 4 and Figure 5).

gas—is a much stronger in greenhouse gas potential than CO_2 in the short run. Credible estimates of upstream emissions are difficult to come by and beyond the scope of this paper. However, given our estimates of the marginal reduction in greenhouse gas emissions, we can calculate an upper-bound on upstream emissions at which natural gas production would be beneficial, on net.

Setting the marginal benefit of produced natural gas deliveries—in billion cubic feet per-day of natural gas—equal to the marginal costs of production, we have the following:

$$\textit{marginal benefits in generation} \equiv \eta_1 = p \cdot \mu \equiv \textit{marginal costs from leaks}$$

where μ represents the conversion of a bcf/day to metric tons of CO_2 and p represents the (unknown) leak rate, when marginal benefits and marginal costs are in balance. Our estimate for η_1 comes from our main specification—regressing CO_2 emissions from coal and natural gas generation on deliveries—used to generate Figure 7. To calculate μ, we assume that 94.9% of natural gas is methane, consistent with the estimate offered by the National American Energy Standards Board (AESB).[21] We use a baseline greenhouse gas potential (GWP) factor of 32 for methane. This is the midpoint of the range offered by the Intergovernmental Panel on Climate Change (IPCC), Fifth Assessment Report (AR5, 2013), which assumes a 100 year time window.

Under these assumptions we estimate the "break-even leak rate" at 3.3 percent. The estimate is seemingly low, leaving little margin for error on the part of producers, but unsurprising given the greenhouse gas potential of methane. Comparing this result to estimates of actual leaks yields favorable results for natural gas production. The EPA currently estimates the methane leak rate to be around 1.4 percent.[22] A recent study from Alvarez et al., 2018 places the methane rate at closer to 2.3 percent. At a methane leak rate of 1.4 to 2.3, in the context of the electricity sector, our estimates suggests that the Shale Boom has been favorable on net, however, actual upstream methane emissions are cutting significantly into this margin.

To account for uncertainty in the GWP of methane over a 100 year time window, we examine the full range of estimates presented in the IPCC Fifth Assessment Report: a GWP of 28 to 36. In addition, we consider the range of 87 to 96 percent methane per unit of natural gas given by the AESB. Using the upper and lower bounds of these estimates, our

[21] A range of estimates for the fraction of methane per unit of natural gas can be found here https://www.naesb.org/pdf2/wgq_bps100605w2.pdf.

[22] http://theconversation.com/the-us-natural-gas-industry-is-leaking-way-more-methane-than-previously-thought-heres-why-that-matters-98918

estimate of the impact of natural gas production suggests a break even leak rate of between 2.9 and 4.1 percent. When considering this lower bound estimate of 2.9 percent, there appears to be very little societal surplus from shale production. These findings illustrate the importance in efficient management of methane missions by producers. This has especially significant implications for the pursuing rollback of the Obama-era Methane Rule, which would loosen current emissions requirements from oil and gas operations. Considering the narrow margins that we find from shale production—and the relatively low abatement cost found in the literature (Marks, 2018)—stringent standards on emissions from oil and gas production could play a critical role.

8 Conclusion

In this paper we evaluate how the Shale Revolution altered the U.S. electricity mix. Using the 1990 natural gas interstate pipeline infrastructure to identify which states where impacted by the large increase in natural gas production, we identify the effect of more natural gas deliveries and national production on fuel specific generation shares. We show evidence that exposure to the Shale Revolution, thanks to pre-exsting natural gas pipeline infrastructure, resulted in a smaller share of electricity being produced by wind turbines and coal plants and a larger share produced from natural gas plants. Incorporating data on annual generation capacity by fuel type, we show the reduction in coal's generation share happens in the short run, while the effect of wind's generation share is due to long run changes in capacity.

We use these estimates to construct a counterfactual energy mix, as if the Shale Revolution had never happened. We show, had natural gas production remained at it's 2005 level, so too would natural gas's share of electricity generation. More electricity would be generated from coal and wind turbines. Interestingly, our results suggest there would have been a decline of coal regardless of the Shale Revolution and part of coal's generation share would be replaced by renewable generation. We directly look at the resulting impact on overall carbon emissions from the electric power sector. We find that the shale revolution had a statistically significant impact on total carbon dioxide emissions, however the reduction in CO_2 is not as large as suggested by the Energy Information Agency.

With these results, we outline a number mechanisms. The obvious of which is the effect of natural gas deliveries on natural gas prices. We show support for our methodology, showing how predicted deliveries reduce natural gas prices. We briefly discuss the role of environmental regulations and inevitable plant retirement on coal generation's share, and provide limited evidence of how the shale revolution might have reduced the stringency of renewable portfolio standards. Finally, we discuss how upstream leakage of methane might undermine the environmental benefits of the Shale Revolution, providing a upper bound break even leakage value slight above current estimates of leakage.

Overall, our results highlight the long run substitution of technologies to generate electricity in response to a supply shock. Although there are direct environmental benefits of the Shale Revolution, our results suggest hydraulic fracturing can preempt less carbon intensive technologies and should be pursued as a means of reducing carbon emissions with caution.

References

Allcott, Hunt and Daniel Keniston. 2017. "Dutch disease or agglomeration? The local economic effects of natural resource booms in modern America." *The Review of Economic Studies* 85 (2):695–731.

Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, Scott C. Herndon, Daniel J. Jacob, Anna Karion, Eric A. Kort, Brian K. Lamb, Thomas Lauvaux, Joannes D. Maasakkers, Anthony J. Marchese, Mark Omara, Stephen W. Pacala, Jeff Peischl, Allen L. Robinson, Paul B. Shepson, Colm Sweeney, Amy Townsend-Small, Steven C. Wofsy, and Steven P. Hamburg. 2018. "Assessment of methane emissions from the U.S. oil and gas supply chain." *Science* 361 (6398):186–188.

Anderson, Soren T, Ryan Kellogg, and Stephen W Salant. 2018. "Hotelling under pressure." *Journal of Political Economy* 126 (3):984–1026.

Bartik, Alexander W, Janet Currie, Michael Greenstone, and Christopher R Knittel. 2019. "The Local Economic and Welfare Consequences of Hydraulic Fracturing." *American Economic Journal: Applied Economics* .

Bartik, Timothy. 1991. "Who Benefits from State and Local Economic Development Policies." *W.E. Upjohn Institute* .

Brehm, Paul. 2019. "Natural gas prices, electric generation investment, and greenhouse gas emissions."

Cascio, Elizabeth U and Ayushi Narayan. 2015. "Who needs a fracking education? the educational response to low-skill biased technological change." Tech. rep., National Bureau of Economic Research.

Cullen, Joseph A and Erin T Mansur. 2017. "Inferring carbon abatement costs in electricity markets: A revealed preference approach using the shale revolution." *American Economic Journal: Economic Policy* 9 (3):106–33.

Currie, Janet, Michael Greenstone, and Katherine Meckel. 2017. "Hydraulic fracturing and infant health: New evidence from Pennsylvania." *Science advances* 3 (12):e1603021.

Deschenes, Olivier and Kyle C. Meng. 2018. "Quasi-Experimental Methods in Environmental Economics: Opportunities and Challenges." *NBER Working Paper 24903* .

EIA. 2018. "U.S. Energy-Related Carbon Dioxide Emissions, 2017." Tech. rep., US Energy Information Agency.

Fell, Harrison and Daniel T Kaffine. 2018. "The fall of coal: Joint impacts of fuel prices and renewables on generation and emissions." *American Economic Journal: Economic Policy* 10 (2):90–116.

Feyrer, James, Erin T Mansur, and Bruce Sacerdote. 2017. "Geographic dispersion of economic shocks: Evidence from the fracking revolution." *American Economic Review* 107 (4):1313–34.

Gillingham, Kenneth and Pei Huang. 2019. "Is Abundant Natural Gas a Bridge to a Low-carbon Future or a Dead-end?" *Energy Journal* 40 (2).

Gray, Wayne, Joshua Linn, and Richard Morgenstern. 2019. "The impacts of lower natural gas prices on jobs in the US manufacturing sector." *The Energy Journal* 40 (5).

Hausman, Catherine and Ryan Kellog. 2015. "Welfare and Distributional Implications of Shale Gas." *Brookings Papers on Economic Activity* .

Holladay, J Scott and Jacob LaRiviere. 2017. "The impact of cheap natural gas on marginal emissions from electricity generation and implications for energy policy." *Journal of Environmental Economics and Management* 85:205–227.

James, Alexander and Brock Smith. 2017. "There will be blood: Crime rates in shale-rich US counties." *Journal of Environmental Economics and Management* 84:125–152.

Johnson, Reid, Jacob LaRiviere, and Hendrik Wolff. 2019. "Fracking, coal, and air quality." *Journal of the Association of Environmental and Resource Economists* .

Knittel, Christopher, Konstantinos Metaxoglou, and Andre Trindade. 2016. “Are we fracked? The impact of falling gas prices and the implications for coal-to-gas switching and carbon emissions.” *Oxford Review of Economic Policy* 32 (2):241–259.

Knittel, Christopher R, Konstantinos Metaxoglou, and André Trindade. 2019. “Environmental implications of market structure: Shale gas and electricity markets.” *International Journal of Industrial Organization* 63:511–550.

Linn, Joshua and Lucija Muehlenbachs. 2018. “The heterogeneous impacts of low natural gas prices on consumers and the environment.” *Journal of Environmental Economics and Management* 89:1–28.

Marks, Levi. 2018. “The Abatement Cost of Methane Emissions from Natural Gas Production.” *Working Paper* .

Muehlenbachs, Lucija, Elisheba Spiller, and Christopher Timmins. 2015. “The housing market impacts of shale gas development.” *American Economic Review* 105 (12):3633–59.

Newell, Richard G and Daniel Raimi. 2014. “Implications of shale gas development for climate change.” *Environmental science & technology* 48 (15):8360–8368.

Shearer, Christine, John Bistline, Mason Inman, and Steven J Davis. 2014. “The effect of natural gas supply on US renewable energy and CO2 emissions.” *Environmental Research Letters* 9 (9):094008.

Solon, Gary, Steven J Haider, and Jeffrey M Wooldridge. 2015. “What are we weighting for?” *Journal of Human resources* 50 (2):301–316.

Tour, James M, Carter Kittrell, and Vicki L Colvin. 2010. “Green carbon as a bridge to renewable energy.” *Nature materials* 9 (11):871.

Appendix

A Linking pipeline capacity

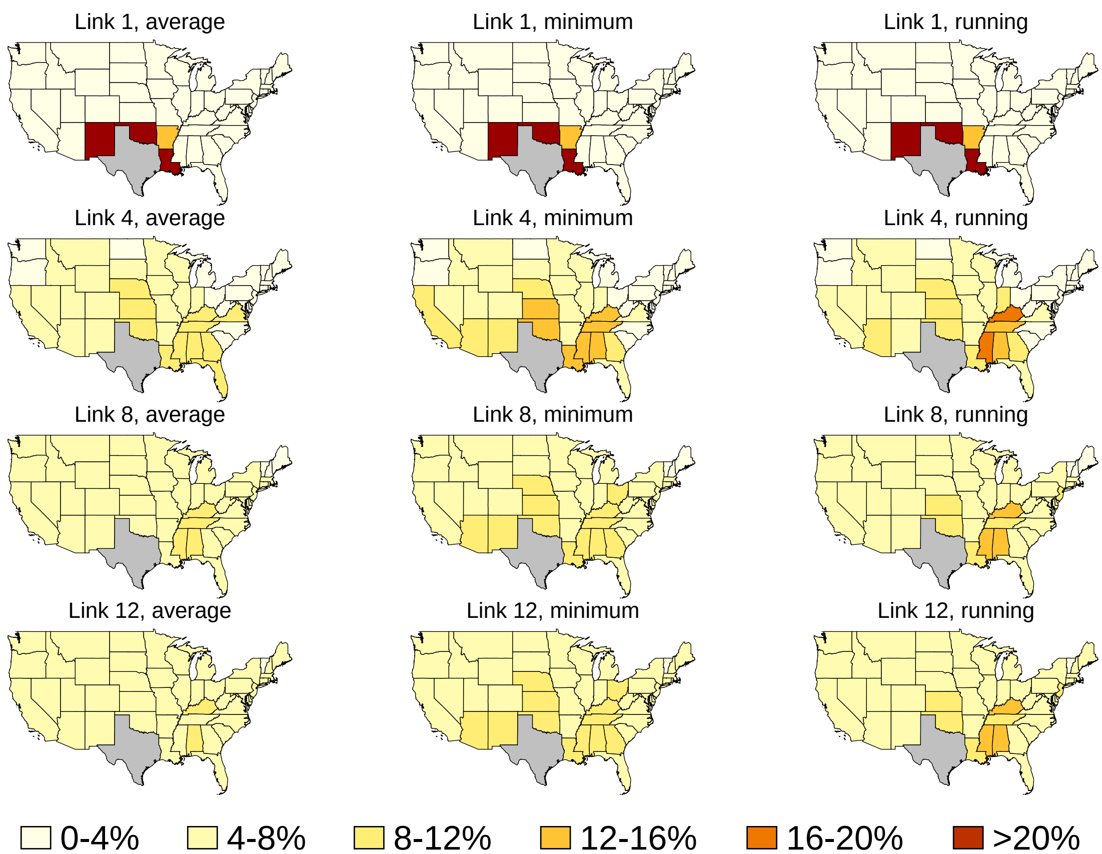
We entertain three ways to link interstate pipeline capacity to get a measure of $EffectiveCapacity$, shown in Equation 6. The first, we denote as "average". If state j has outflow to state i but not state k, and state i has outflow to state k, we say the effective capacity from state j to state k is the average of the capacity from state j to state i and from state j to state k. This is an example of a two link measure of effective capacity. We consider all iterative linkages. Ultimately we use 13 "average" linkages in our preferred specification.

Alternatively, we consider a "minimum" and a "running" method for linkages. With the example provided above, we would say that the "minimum" effective capacity from state j to state k is the minimum of the capacity from state j to state i and from state i to state j. In the example above, the "running" effective capacity would take the capacity from j to i, and weight it by the fraction of outflow going from i to k, before adding the outflow capacity for k. Figure 9 shows the weights of w_{ij} leaving Texas for all three methods, and linkages of length 1, 4, 8, and 12.

B Robustness of Results

We start by considering the importance of the method in which we construct the pipeline network. Table 6 presents the estimates similar to column 6 of Table 3, however the method used to calculate the pipeline linkages differs. Columns 1 to 3 use the average method, columns 4-6 uses the minimum method, and columns 7-9 uses the running method. The columns are distinguished by the number of linkages between states. To get an idea of how they differ, Figure 9 shows the three methods for the number of linkages used. We see the point estimates and their significance differ depending on the method used, however the relative relationship of the point estimates and their sign remains relatively constant. We see the relationship between shale exposure and actual deliveries, as measured by the first stage F statistic, is weak in most of the regressions except for the average method with the most number of linkages.

Figure 9: Alternative Pipeline Linkages



Note: Outflow weights from Texas using three different methods, and four linkage lengths.

Table 6: Alternative Pipeline Weights.

	1	2	3	4	5	6	7	8	9
Panel A:	Nat. Gas Generation Share [mean=16.03]								
$GasDeliveries_{it}$	7.97	8.08	8.09	13.62	13.52	13.52	14.21	14.45	14.45
	1.17	1.20	1.20	12.24	11.97	11.97	57.89	74.55	74.55
Panel B:	Coal Generation Share [mean=47.94]								
$GasDeliveries_{it}$	-4.06	-3.79	-3.79	-9.92	-9.70	-9.70	-10.74	-9.36	-9.36
	1.44	1.39	1.39	13.42	12.98	12.99	59.87	66.30	66.30
Panel C:	Wind Generation Share [mean=1.64]								
$GasDeliveries_{it}$	-4.81	-4.91	-4.91	-13.12	-12.99	-12.99	-36.93	-45.18	-45.18
	1.42	1.47	1.47	18.08	17.71	17.71	236.38	365.78	365.76
State FE	Y	Y	Y	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y	Y	Y	Y
Own State Production	Y	Y	Y	Y	Y	Y	Y	Y	
1st Stage F-statistic	10.95	10.79	10.79	4.42	4.31	4.31	2.34	2.24	2.24
Method		Average			Minimum			Running	
Linkages	8	10	12	8	10	12	8	10	12

Notes: Each panel corresponds to different fuel generation shares as the dependent variable, in percentage points. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year. The method used to link pipelines is described in Appendix A.

Because development of wind turbines can only happen in select states, and that might happen to be correlated with legacy connections to shale production potential, we re-estimate our structural results selecting on only states that have wind potential in addition to states that have no wind potential in Table 7. Columns 1 and 2 are columns 3 and 6 from Table 3, repeated for easy reference. Columns 3 and 4 estimates the same parameters, however only using observations for states that have some sort of wind potential. In particular, we exclude any state in the south eastern United States.[23] Columns 5 and 6 consider the opposite, and excludes states that have the highest wind potential.[24] We see that the point estimates shift slightly, as to be expected, but the results remains within the same margin of error.

Finally, we consider an alternative approach to identify the effect of the shale revolution on electricity generation share. Our main approach assumes that the interconnections between states based on the preexisting pipeline infrastructure sufficiently proxies for the constraints on natural gas deliveries a state faces, well into the future. An alternative would be to take a baseline level of natural gas receipts, pre-boom, as an imperfect indicator for how much each state will be affected by gas transfers, post-boom. We see our instrument as an improvement on this approach, as we exploit quasi-random connections to states with a high potential for future shale gas production. Nevertheless, we test this alternative approach by estimating the following alternative first stage.

$$gas\ delivered_{it} = \tilde{\beta}_1 \cdot receipt\ share_{i0} \times production_t + \tilde{\beta}_2 \cdot production_{it} + \tilde{\gamma}_i + \tilde{\delta}_t + \tilde{\varepsilon}_{it} \qquad (9)$$

This approach simply holds constant the endogenous part of our main regressor, receipt shares, at their initial levels, *receipt share*$_{i0}$. The two-stage least squares results for this alternative approach are presented in Table 8. The estimates are similar to those of our main results. Not surprisingly, the first stage produces a lower F-statistic, arguing that our main approach, which exploits the pipeline connections to shale-rich areas, is more predictive of states that are ultimately more impacted by the Shale Revolution.

[23] This states excluded from the sample are Florida, Georgia, Alabama, South Carolina, Alabama, Tennessee, North Carolina, Mississippi, Virginia, West Virginia, and Kentucky.

[24] This excludes Texas, Oklahoma, Kansas, Iowa, Indiana, South Dakota, North Dakota, Colorado, Minnesota, Michigan, Oregon, and California.

Table 7: Sample Selection

	1	2	3	4	5	6
Panel A:	Nat. Gas Generation Share [mean=16.03]					
$ReceiptShare_{it} \cdot NationalProduction_t$	8.09	8.19	8.38	7.75	8.82	9.76
	(1.20)	(1.23)	(1.81)	(1.31)	(1.75)	(2.01)
Panel B:	Coal Generation Share [mean=47.94]					
$ReceiptShare_{it} \cdot NationalProduction_t$	-3.79	-3.77	-3.50	-3.44	-5.92	-7.26
	(1.39)	(1.30)	(1.66)	(1.43)	(1.88)	(1.84)
Panel C:	Wind Generation Share [mean=1.64]					
$ReceiptShare_{it} \cdot NationalProduction_t$	-4.91	-5.39	-6.14	-5.53	-2.58	-3.04
	(1.47)	(1.57)	(2.17)	(1.85)	(1.01)	(1.20)
Panel D:	Solar Generation Share [mean=0.09]					
$ReceiptShare_{it} \cdot NationalProduction_t$	0.28	0.22	0.68	0.49	0.08	-0.01
	(0.25)	(0.22)	(0.62)	(0.47)	(0.13)	(0.17)
Panel E:	Hydro Generation Share [mean=10.45]					
$ReceiptShare_{it} \cdot NationalProduction_t$	1.26	1.26	1.54	1.13	0.80	1.31
	(0.91)	(0.99)	(1.38)	(1.21)	(0.76)	(0.92)
Panel F:	Nuclear Generation Share [mean=18.71]					
$ReceiptShare_{it} \cdot NationalProduction_t$	1.47	1.97	2.42	2.56	2.23	3.93
	(1.04)	(1.07)	(1.75)	(1.54)	(1.77)	(2.35)
Observations	1152	1152	912	912	864	864
State FE	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y
Own State Production	Y	Y	Y	Y	Y	Y
Instrument	PG	SE	PG	SE	PG	SE
Sample	Full Sample		Wind Potential		No Wind Potential	

Notes: Each panel corresponds to different fuel generation shares as the dependent variable, in percentage points. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year. Wind Potential sample excludes the south eastern United States, No wind potential excludes the states in the great plains, Texas, and California.

Table 8: Impact of National Production on Generation Shares: Alternative Approach

	1	2
Panel A:	Nat. Gas Generation Share [mean=16.03]	
$ReceiptShare_{it} \cdot NationalProduction_t$	8.44	7.14
	(0.79)	(0.97)
Panel B:	Coal Generation Share [mean=47.94]	
$ReceiptShare_{it} \cdot NationalProduction_t$	-5.94	-6.55
	(2.05)	(2.32)
Panel C:	Wind Generation Share [mean=1.64]	
$ReceiptShare_{it} \cdot NationalProduction_t$	-3.80	-3.19
	(0.68)	(0.79)
Panel D:	Solar Generation Share [mean=0.09]	
$ReceiptShare_{it} \cdot NationalProduction_t$	-0.34	-0.62
	(0.66)	(0.75)
Panel E:	Hydro Generation Share [mean=10.45]	
$ReceiptShare_{it} \cdot NationalProduction_t$	0.10	0.77
	(1.07)	(1.15)
Panel F:	Nuclear Generation Share [mean=18.71]	
$ReceiptShare_{it} \cdot NationalProduction_t$	1.65	2.08
	(1.20)	(1.28)
mean $s_{it} \cdot NationalProduction_t$	1.07	
mean $NationalProduction_t$	51.45	
Observations	1152	1152
State FE	Y	Y
Year FE	Y	Y
Own State Production	N	Y
1st Stage F-statistic	1.89	2.06

Notes: Each panel corresponds to different fuel generation shares as the dependent variable, in percentage points. Standard errors, clustered at the state level, are in parenthesis. State-year observations are weighted according to the total amount of energy produced in a given year.