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

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Abstract

We examine the effects of the Shale Revolution on the U.S. energy mix and greenhouse gas emissions using the preexisting pipeline infrastructure as plausibly exogenous exposure to an abundance of natural gas. We find more natural gas production decreases electricity generated from wind turbines and coal power plants, having countervailing implications for greenhouse gas emissions. In sum, we estimate that natural gas production has only modest net environmental benefits. Further, we calculate a natural gas leakage-rate greater than 3.3 percent negates the environmental benefits of the Shale Revolution, highlighting the importance of efficient emissions management in natural gas production.

JEL classification codes: Q33, Q4, Q5, L71, L94

1 Introduction

Over the past fifteen years 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. The most contentious aspect of this resource boom is the effect of more natural gas production on greenhouse gas emissions from the electric power sector. Some argue natural gas provides environmental benefits by replacing greenhouse gas intensive fuels like coal and petroleum (Tour, Kittrell, and Colvin, 2010; Tanaka et al., 2019). Conversely, simulations suggest natural gas crowds out investment in other low-carbon technologies like wind turbines and solar panels (e.g., Newell and Raimi, 2014). Underlying this debate is exact magnitude of how natural gas production affects the share of electricity generated from these different technologies in actuality, which to-date remains unanswered.

In this paper, we empirically document the causal impact of more natural gas production on the U.S. electricity mix and provide a counterfactual fuel mix, as if the Shale Revolution had never happened. We find more natural gas production reduces the share of electricity generated from both coal power plants and wind turbines equally. We show the mechanisms differ: natural gas displaces coal generation in the short-run and wind turbine investment in the long-run. Our estimates imply positive-yet-modest environmental benefits from natural gas production induced reductions in greenhouse gas emissions, and that these benefits are lost if more than 3.3 percent of natural gas leaks into the atmosphere along the supply chain. This result digresses from industry and government reports[1] because they over-attribute coal's decline to natural gas production and ignore the substitution between natural gas production and wind turbine investment.

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.[2] For example, there is a problem of simultaneity in that the quantity of natural gas delivered and realized fuel mix are co-determined by supply and demand. In this paper we address this challenge using the pre-existing legacy inter-state pipeline network—from 1990—to isolate which states were exogenously exposed to more natural gas prior to the 2006 production boom. In doing so, we estimate how natural gas production substitutes for different electricity generation technologies using a generalized difference-in-differences and instrumental variables approach.

[1] For example (EIA, 2018, p. 12) lists "the emissions reductions from shift towards natural gas" as the number one contributer to greenhouse gas emission reductions for every year since 2005.

[2] Coincident to the shale revolution there were a number of state and federal policies to encourage the adoption of renewable generation, a significant increase in cost-effectiveness of wind turbines and solar panels, a larger build out of new natural gas electricity generators, and an economic downturn that reduced demand for electricity.

Specifically, we exploit quasi-random out-of-state production of natural gas—variation plausibly exogenous to in-state factors governing the use of different fuels. We leverage the 1990 natural gas pipeline infrastructure to infer how one state's production affects another state's natural gas deliveries, independently of other factors. In this sense, we are able to overcome bias from confounding unobservables related to a state's own-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 use an alternative instrument which combines variation in exposure to production *potential*—mainly, the total physical 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. 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 the 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.

Most directly this paper is contributing to the rich literature evaluating the economic consequences of the Shale Revolution such as 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 impacts of natural gas at the national level. Second, we are the first to utilize the legacy natural gas pipeline network as a source of identifying variation. This is in comparison to existing studies that identify off of variation across narrowly defined geographic regions, or a single time series.

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 use to generate electricity, 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[3] 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 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), and capacity investment (Brehm, 2019). Largely these papers use longitudinal natural gas price variation resulting from the Shale Revolution, and typically only consider the switching of coal for natural gas. Our approach builds on these papers using a novel identification strategy, and diverges from them in two ways.

First, we are unique in evaluating the effect of increased natural gas production, not a decrease in 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 wells. Second, we are the first to evaluate the effects of the Shale Revolution on all fuel types, not just coal generation. In doing so, we are able to better characterize the complete effects of the Shale Revolution and present a counterfactual

[3] For example see Butner (2019); Woerman (2019)

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 briefly present our counterfactual fuel mix while Section 7 explores some of the mechanisms including how the Shale Revolution impacted natural gas prices, the implementation of Renewable Portfolio Standards, and why the Shale Revolution doesn't completely explain the decline of coal. In Section 8 we reconcile the countervailing effects of natural gas production on wind and goal generation by directly estimating how the Shale Revolution impacted carbon emissions from the electricity power sector and outline the implications of our results for a "break-even" methane leakage rate. Section 9 concludes.

2 Background

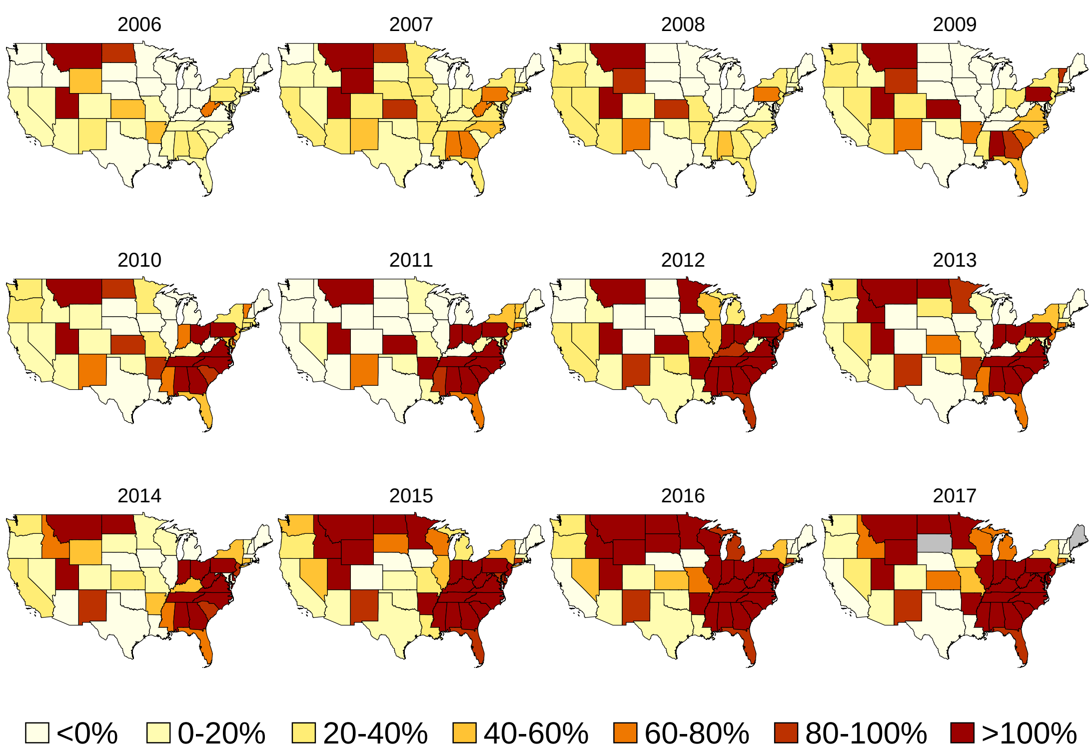
The existence of large natural gas and petroleum reserves in shale has been long established. However, these reserves were largely seen as uneconomic and hard to access because the resources were interlaced in a honeycomb of shale rock, much unlike the large pools of oil and gas extracted from conventional wells. The economics of natural gas production changed with 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.[4] 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 pro-

[4] 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 that document how the Shale Revolution impacted the electricity sector. In application, our empirical approach generalizes this discrete start time by using natural gas production as a continuous measure.

duction from shale went from 4.2 billion cubic feet per day (bcf/day) in 2005 to almost 70 bcf/day in 2019.[5] Shale gas production is concentrated in few key locations and the most productive area has changed over time. The first states to produce shale gas were Texas and Louisiana, followed by the Mid-Atlantic states around 2011. Production from the Rocky Mountain states, including North Dakota and Montana is small in comparison to the Mid-Atlantic and parts of Texas, but has increased in recent years. 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.

Figure 1: National Impact of the Shale Revolution



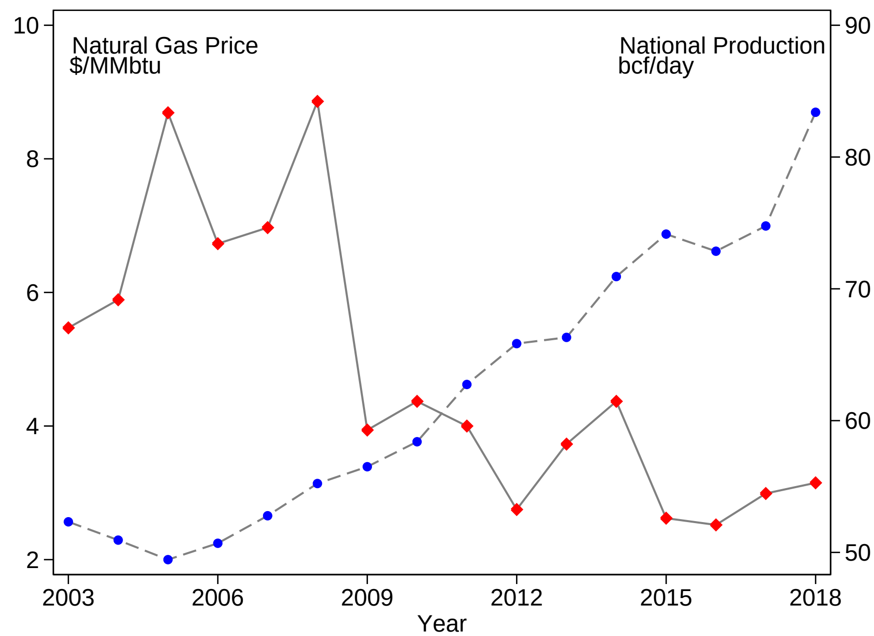
Note: % change in volume of natural gas delivered to electric power customers from 2005, EIA. The EIA reports no data for South Dakota and Maine in 2017 to avoid disclosure of individual company data.

The most immediate impact of more natural gas production is on the price of natural

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

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.[6] 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 their profitability is the "spark spread", representing the difference between the price of electricity and cost of production from a natural gas electricity generator per unit of electricity sold.[7] As the spark spread increases, natural gas became more attractive relative to other sources of electricity generation.

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.

Electricity in the United States is generated by a diverse mix of resources. Since the 1950s, around half of all electricity has been generated by power plants using coal. The residual electricity has been provided by different fuel sources overtime, 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

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

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

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.[8] 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 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, a utility's discretion, or bilateral contracts. Broadly, the objective is to generate enough electricity to meet the relatively inelastic demand for electricity while minimizing the cost of production.

In the case of wholesale markets, for example, an impartial market operator solves a constrained optimization problem to determine which electricity generators are "dispatched" to generate electricity. As lower natural gas prices reduce the cost of production for natural gas plants, wholesale market operators and utilities will prefer to dispatch natural gas plants relative to more expensive coal or petroleum power plants. We do not expect natural gas to substitute for wind or solar based resources because their output is primarily determined by weather patterns. The same logic applies to short run bilateral contracts and a utilities internal operations. Evidence of this short run switching of fuels 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

8 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.

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 infra-marginal electricity generators, like nuclear power plants, even if they are not directly displaced in the merit order. If a plant's margins are too small, this change in the price 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 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.

To illustrate the point on relative fuel costs, consider the case of a public utility advertising a competitive, technology neutral, Request For Proposals for new generation capacity.[9] 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 increases relative to a wind turbine, increasing the long run capacity in natural gas. Similarly, for utilities that already own natural gas plants, a lower natural gas price makes it more difficult for them to buy electricity from a third party through a long-run contract. This is because the purchase can only be justified if the price of electricity is less than the cost they avoid through the purchase, their "avoided-cost." As natural gas prices decline, so too does their avoided cost, making it difficult for them to sign bilateral contracts for electricity. Broadly, the logic favoring natural gas because of relative fuel costs extends to merchant electricity generators in wholesale markets.

The change in the price of electricity, as a result of the Shale Revolution, is perhaps more relevant for merchant electricity generators operating in a wholesale market. This is because of the wholesale price of electricity is public information and is a reference price for long-run purchasing power agreements. Abundant natural gas suppresses the wholesale price of electricity, and as a result makes it harder for merchant electricity generators to finance their projects. This is especially the case for wind turbines, as they are predominately financed through long-run purchasing power agreements.

Overall, we expect more natural gas deliveries to be associated with less generation from

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

coal in the short run, as lower natural gas price makes natural gas more attractive than coal. 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 the switching of fuel capacity for marginal demand growth, retirements, and coal-to-gas switching.

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 and be utilized 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 investment 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.

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

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, $S_k = gas\ delivered_k + \phi_k \cdot q_k$, where S_k defines k's total supply of natural gas and *gas delivered* is as defined in Equation 1. Any given period, the state keeps some portion of its production, $\phi_k \in [0, 1]$—where $\phi_k = 1 - \sum_{i \in N} w_{kit}$—and distributes the remainder, $1 - \phi_k$, 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.

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

We control for in-state production, $production_{it}$—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. 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.

We proxy for state-to-state delivery shares, w_{jit}, using state-to-state pipeline capacities. This approach assumes that capacities correlate with actual delivery quantities. We value this approach because the long-run pipeline capacity is likely to be uncorrelated with year-to-year confounding factors. Further, as the evolution of the pipeline infrastructure is could be 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 decisions 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.

$$\textit{shale exposure}_{it} = \textit{production}_t \cdot \sum_{j \in N} \tilde{w}_{ij} \times \textit{shale}_j \tag{4}$$

where $\textit{shale}_j$ denotes the square mileage of known shale reserves in state j—a proxy for production potential—and $\textit{production}_t$ is national-level production at time t.[10]

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 between producers and consumers (as in Equation 1) are not directly observable to us,[11] we use national delivery shares and national production as a measure of *gas delivered*. Doing so creates a straight-forward representation of the causal effect of aggregate gas production. To illustrate, we define an alternative construct of a proxy for natural gas deliveries

[10] That is, $\textit{production}_t = \sum_{j \in N} \textit{production}_{jt}$.

[11] Though EIA-176 tracks the disposition of natural gas between states, discussions with EIA staff confirm these data represent downstream shipments of processed natural gas and are therefore not consistent with our empirical strategy exploiting variation in upstream production.

as follows,

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

where $production_t$ is the same as in Equation 4 and $receipt\ share_{it}$ is the share of interstate natural gas delivered for use by electric power producers.[12]

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 so that a megawatt of generation is treated equally among all states, rather than under-emphasizing states with overall much higher levels of generation (Solon, Haider, and Wooldridge, 2015).

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.

[12] Our proxy for $gas\ delivered_{it}$ is not exact. Ideally, $production_t$ would represent the total natural gas produced for interstate trade, and $receipt\ share_{it}$ would be the share of natural gas delivered to customers for any use. Hence, our proxy is mis-measured and our estimates are potentially biased downwards (Hausman, 2001). We address this through our instrumental variables approach. Further, we can re-estimate our results using exact measures of $receipt\ share_{it}$ and $production_t$ for interstate trade for a subset of years (1997 forwards) and recover almost identical estimates.

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 Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers".

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 $\tilde{\boldsymbol{W}}_t$ 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

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

Unfortunately, our data on state-to-state pipeline capacity are only recorded for pairs of states which share a border with each other. 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, as to incorporate all available information on inter-state capacities into our measure. We contend an average of capacities is a superior to a single, potentially inexact, capacity measure (e.g., min). In Appendix A, we demonstrate robustness of this approach by proposing an alternative instrument that is independent of the linkage methodology: baseline empirical delivery shares. This approach produces similar results.

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 be used to determine which states were more impacted by the Shale Revolution. We denote these 1990 shares as $\tilde{\boldsymbol{W}}$. 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 $\tilde{\boldsymbol{W}}$ 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.[13]

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.[14] These ignore CO_2 emissions from petroleum based electricity generation, local air pollutants (like NO_x & PM2.5) from coal, natural gas, and petroleum, and upstream emissions from the extraction and transportation of coal, natural gas, and petroleum.[15]

5 Main Results

5.1 Graphical Evidence

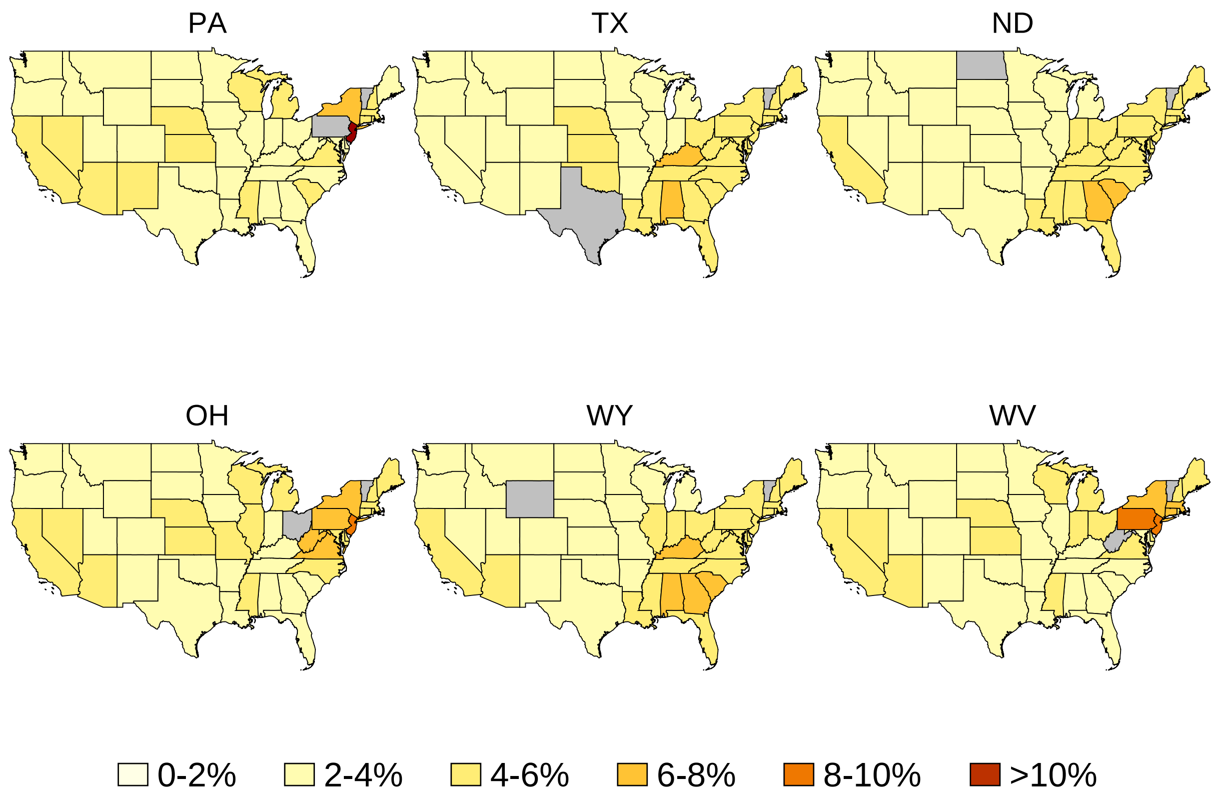
Our empirical strategy is analogous to a generalized difference-in-differences framework, where our event, the Shale Revolution, is not a discrete treatment in time, but rather, a continuous development. We exploit both the timing of production, paired with the interconnections of the pipeline network, 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

[13] See https://www.eia.gov/maps/layer_info-m.php.

[14] 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.

[15] 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.

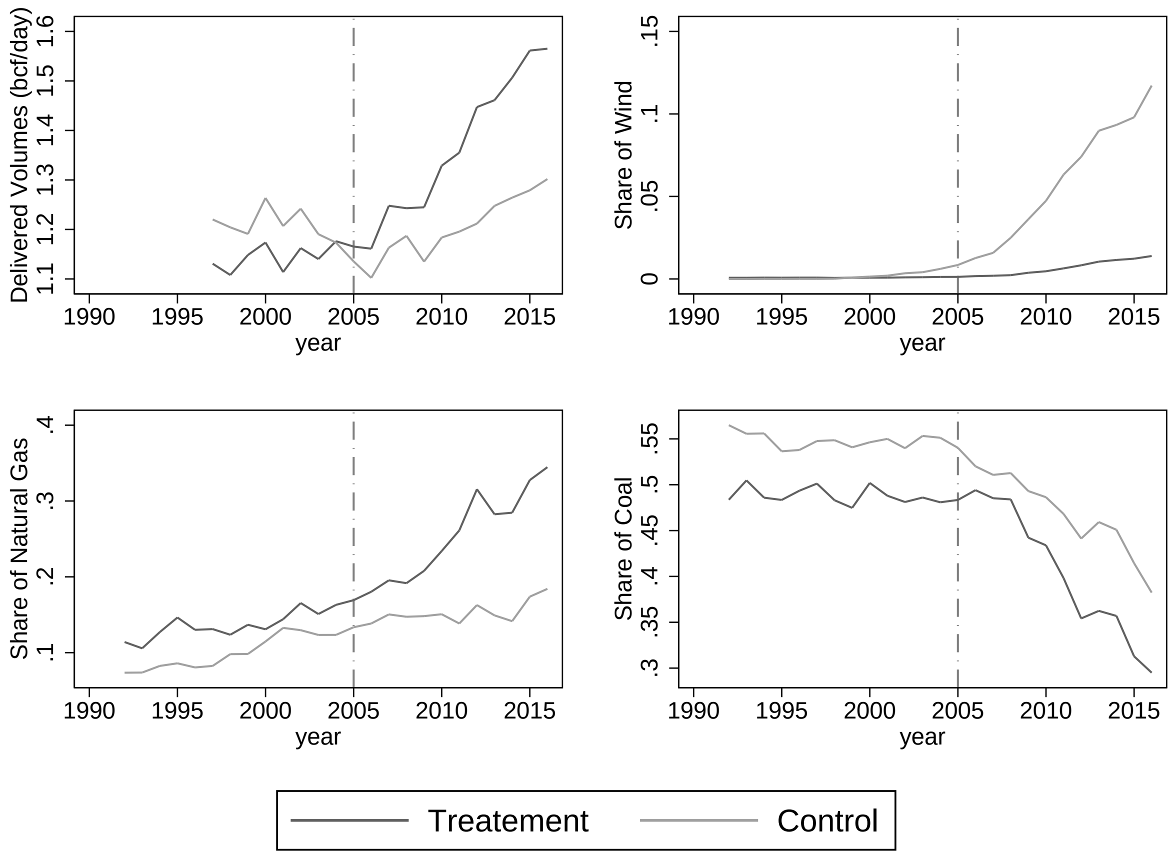
Figure 3: Share of Effective Capacity from States with Large Shale Potential.



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.

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 measure of treatment intensity.

Figure 4: Treatment Intensity from the Shale Revolution

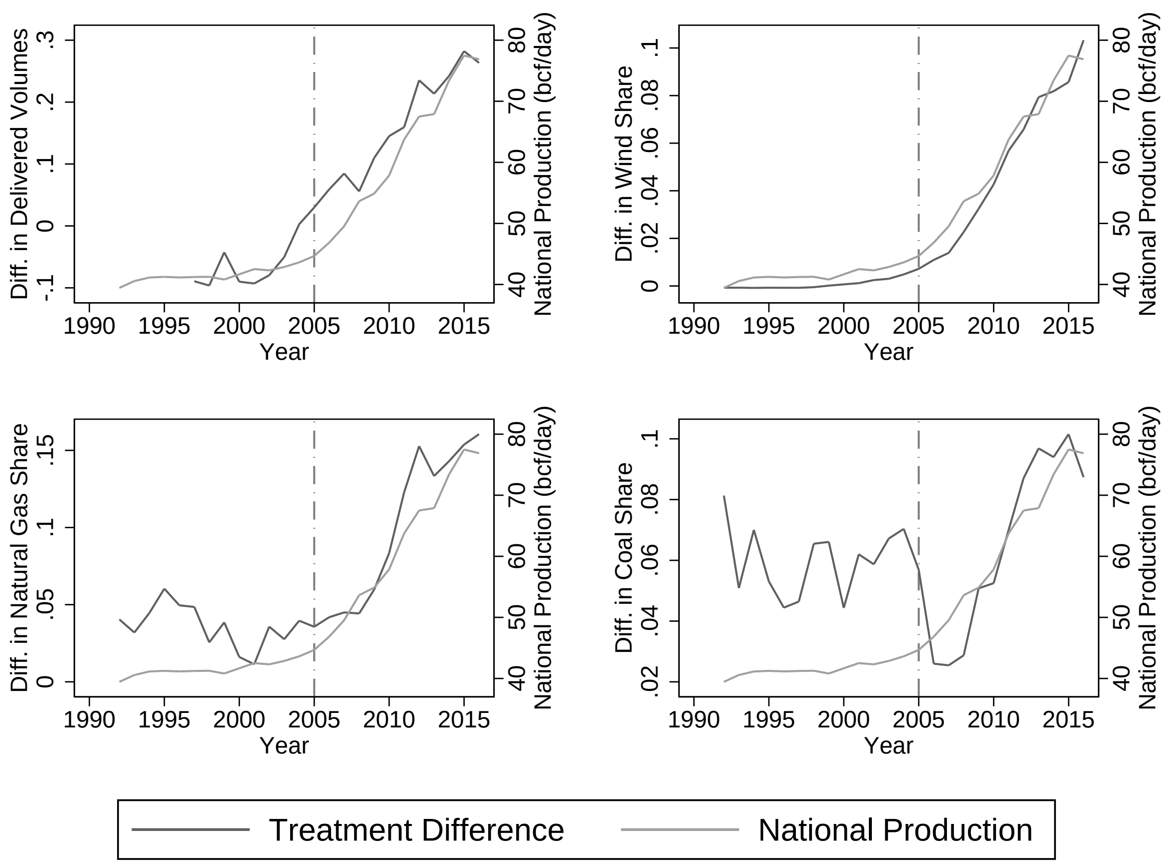


Note: Above splits the outcome variables in to a "treatment" group, defined as states with above median shale exposure (from Equation 4), and a "control" group, defined by below median shale exposure.

Treatment intensity level is best expressed using our measure of shale exposure, defined in Equation 4. In Figure 4, we split our sample 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.[16]

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.

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.

[16] Prior to 2000, the average share of generation from wind was inside of 1 percent (though some states as high as 2 percent), which mechanically reduces the variance around the lower-bound of zero. We test whether this restriction of near-zero baseline wind generation affects our primary estimates by conditioning on years, post-2000. Doing so produces very similar results.

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 are 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 (26.87)	0.62 (25.67)	-27.88 (49.98)	-9.58 (36.95)	-44.09 (45.24)	-37.01 (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, $predicted\ deliveres_{it}$ or $shale\ exposure_{it}$, 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 more natural gas production, and the outcomes of interest: the share of electricity generated by different fuel types.

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).[17] 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

[17] 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.[18]

5.4 Effect of Gas Deliveries and National Production

In this section, we leverage 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 national 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.

[18] 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.

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	N	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 share 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 installed nameplate capacity, in Gigawatts (GW), of different fuel types in Columns 5 and 6.[19] We see more national natural gas production from the Shale Revolution decreases the nameplate capacity for both wind turbines and coal power plants. This reduction in nameplate capacity explains the decline in electricity generation share, especially for wind turbines. Interestingly, more natural gas production does not have a statistically significant effect on natural gas capacity. Though, still meaningful in magnitude, its high variance may be attributed to many states over-investing in combined-cycle natural gas power plants prior to the Shale Revolution (Hill, 2018), and is consistent with estimates evaluating how natural gas prices influenced natural gas capacity investment (Brehm, 2019).

Appendix A walks through some robustness checks. We show the results are robust to sample selection of only states with large wind turbine potential, sample selection of only states with limited wind potential, and an alternative instrument based on historic natural gas deliveries.

[19] We do not look at capacity shares because more natural gas deliveries, as predicted by our *Shale Exposure* instrument, is associated with a decrease in total installed capacity (t-statistic of -1.74).

Table 4: Average Marginal Effect of National Production

	1	2	3	4	5	6
Panel A: Nat. Gas	Generation Share				Capacity GW	
Average Marginal Effect	4.04	4.09	4.69	5.06	0.86	0.63
	(0.60)	(0.62)	(1.80)	(2.24)	(0.66)	(0.76)
Panel B: Coal	Generation Share				Capacity GW	
Average Marginal Effect	-1.90	-1.88	-1.77	-1.77	-0.72	-0.96
	(0.69)	(0.65)	(0.62)	(0.61)	(0.25)	(0.21)
Panel C: Wind	Generation Share				Capacity GW	
Average Marginal Effect	-2.46	-2.70	-0.03	-0.28	-1.31	-1.49
	(0.74)	(0.79)	(0.29)	(0.35)	(0.45)	(0.43)
Panel D: Solar	Generation Share				Capacity GW	
Average Marginal Effect	0.14	0.11	-0.01	-0.01	0.11	0.10
	(0.13)	(0.11)	(0.06)	(0.05)	(0.11)	(0.11)
Panel E: Hydro	Generation Share				Capacity GW	
Average Marginal Effect	0.63	0.63	-0.11	-0.12	0.00	0.00
	(0.46)	(0.50)	(0.14)	(0.17)	(0.02)	(0.02)
Panel F: Nuclear	Generation Share				Capacity GW	
Average Marginal Effect	0.74	0.99	0.83	1.12	0.02	0.02
	(0.52)	(0.54)	(0.53)	(0.53)	(0.04)	(0.04)
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) in percentage points and capacity level (Columns 5 and 6) in Gigawatts (GW). Standard errors clustered at the state level are in parenthesis. PG stands for *Predicted Gas*, SE stands for *Shale Exposure*, each representing the instrument used in the specification.

6 Counterfactual Fuel Mix

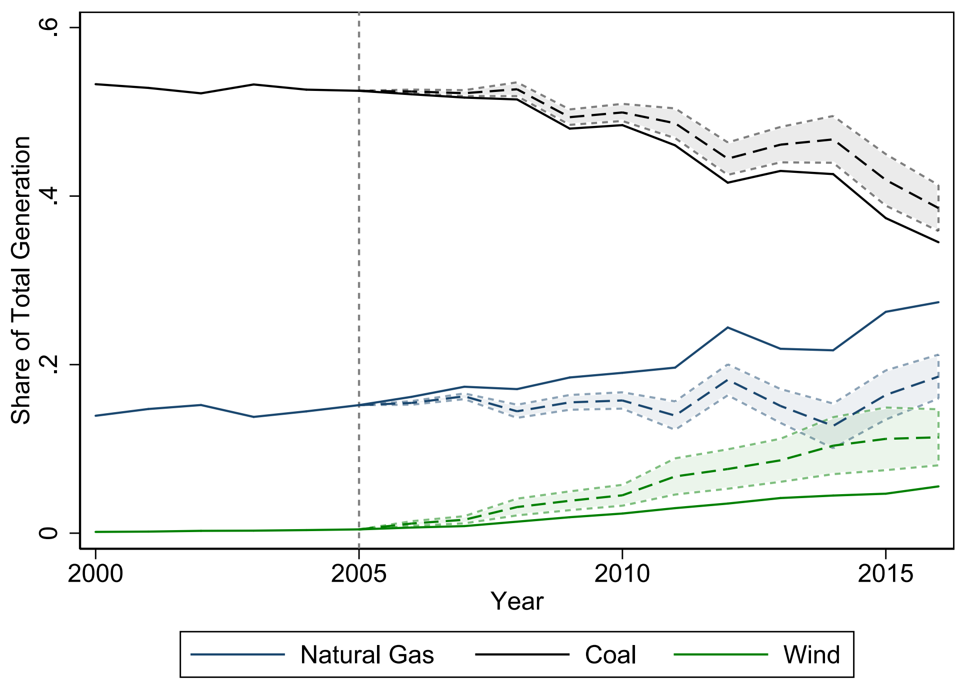
We use our preferred estimates of the effect natural gas deliveries on generation shares, Column 7 of Table 3, to present the counterfactual fuel mix as if the Shale Revolution had never happened. We calculate this counterfactual by taking the observed state-year generation shares for each fuel type,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

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

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.[20] As a result, our counterfactual presents in the fuel mix that cannot explained by changes in natural gas production.

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.

[20] 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 counterfactual 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.

Importantly, our estimates confirm that if natural gas production remained constant at 2005 levels, so too would the share of electricity generated from natural gas. This validates our estimates, as we should not expect generation from gas to change so long as production has remained constant. Interestingly, the share of electricity generated from coal declines in both our counterfactual and in the observed data, however we see less of a decline in our counterfactual. This suggests the Shale Revolution cannot completely explain the decline in coal's generation share from 2005.

We see that electricity generated from wind turbines increases in our counterfactual, suggesting the Shale Revolution stalled investments in wind turbines. In 2016, about 5.6% of 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.[21]

7 Mechanisms and Discussion

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 Revolution pipeline infrastructure—has a corresponding impact on natural gas prices. This effect on natural gas prices explains the preference for natural gas as a generating source, relative to coal or wind.

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 the 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

[21] We estimate total nonrenewable generation, including solar, wind, and hydro, would be between 12 and 16% in 2016 according to our counterfactual. Statistically indistinguishable from the amount of natural gas in our counterfactual. For reference, the actual share of electricity generated from renewable generation in 2016 was 9%.

the effect of a one bcf/day increase in state natural gas deliveries as producing a decrease in natural gas prices of 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	0.02	-0.10	-0.11	-0.24	-0.10	-0.11	-0.22
	(0.01)	(0.01)	(0.04)	(0.04)	(0.16)	(0.04)	(0.04)	(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 express caution against interpreting the scaled two-stage least squared estimates of the impact of natural gas prices on generation shares as causal, as it is possible 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 case, 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-term, average 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

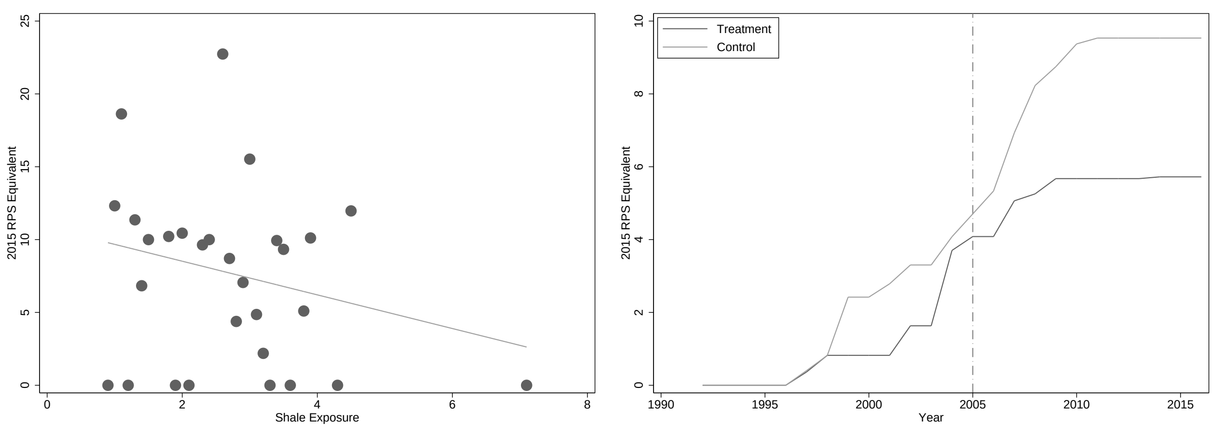
Other than natural gas prices, the formation of state policies in response to the Shale Revolution could have had an impact on the share of electricity generated by different fuel types. In particular, more natural gas at a lower market price makes de-carbonizing the electricity sector less expensive (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, who anticipate their energy mix will become less carbon intensive in the future, may not feel the need to address carbon emissions from the electricity power sector. Such states might be less likely to pass a policy supporting renewable generation technologies, for example a Renewable Portfolio Standard (RPS). With no binding policy to support renewable generation, there will be less deployment of renewable generation resources.

We wish to estimate the magnitude in which the Shale Revolution has impacted a states decision to pass an RPS, and conditional on passing the policy, the stringency of the standard. To address this empirically we create a panel data set of all renewable portfolio standards passed in the United States. Generally, a standard is set as a threshold share of electricity production coming from renewable energy, in which a state must meet as of a given date. Given the dynamic nature of the policies, in measuring the impact of natural gas production on policy action, we must normalize each state's policy to a common metric of the same scale. We use exponential discounting as a means of doing so. To explain, suppose a given state in 2008 passes a standard, mandating 10% renewables by 2025. We want to estimate how natural gas production has influenced this decision. Prior to the 2008 policy, the standard was zero. To account for the aggressiveness of the policy after 2008, we normalize the 10% 2025 mandate by discounting this value back to a common date.[22] For the purposes of this

[22] Sometimes a state has multiple deadlines in which they must achieve different levels of renewable energy production. For these cases, we discount each standard and use the average of these within a state. Further, we observe no adjustments to the standards in our data set, otherwise, we might make use of

exercise, we use a common date of 2015 and a discount rate of 10%. For the example above, our adjustment implies a 2015 equivalent standard of 3.5 percent ($10\% \times \left(\frac{1}{1+0.1}\right)^{2025-2015}$). Since no further policy action (in regards to the standard) takes place after 2008, we maintain this value after the policy was established. We consider this a measure of stringency of the RPS. To the extent to which the rate of compliance follows exponential growth, for each state we can interpret this measure as the RPS equivalent, given a common deadline of 2015.

Figure 7: 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 2015 Equivalent RPS, with slope -1.16 and a robust standard error of 0.63. The right panel shows the dynamic progression of the standard (from zero to potentially non-zero) for treatment (above median shale exposure) and control (below median shale exposure) states (as in Figure 4 and Figure 5).

Given the lack of dynamic progression of the policies, and thus, the limited values in which our metric can take—i.e., zero or a positive standard—we first show how the standards across states correlate with *shale exposure* (defined in Equation 4). The left panel of Figure 7 shows a significant decrease in the standard for states less connected—via pipeline—to shale-rich states. The estimates suggest a 0.3 percentage point reduction in the equivalent standard for a 10% increase in *shale exposure*. The right panel demonstrates the progression of the standard (from zero to potentially non-zero) for states with above ("treatment"), and below ("control"), median *shale exposure*. We see after the occurrence of the Shale Revolution, the average percent mandated in the control states (with lower *shale exposure*) is higher than the average percent mandated in the treatment states (with higher *shale exposure*).

These results suggest that there may be a link between natural gas production and policy mandates targeted at renewable energy production. Given the limited, one-time response in our outcome variable, it may not be appropriate to place too much weight on this finding.

this additional variation.

Furthermore, in our main specification—which regresses RPS equivalent on deliveries by two-stage least squares—we cannot reject a zero effect of production on the renewable standard; though, our results are statistically significant in cross-sectional regressions, as in the left panel of Figure 7. In any case, this suggestive evidence presents an interesting dynamic in which competition in alternative energy sources may potentially impact policy decisions.

7.3 Coal's Decline

Perhaps the most surprising result in our counterfactual is the decline of coal absent the Shale Revolution. We argue that this is probably due inevitable retirements of old power plants, environmental regulations such as the Mercury and Air Toxics Standards (MATS), and decreased productivity at coal mines. 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, and it makes sense for the plant to close. Although we cannot dismiss the possibility that these coal generators would have been replaced with new coal generators, the coincident decline in the cost of renewable and passage environmental regulation suggest might coal would not be the favored investment for new capacity.

The Mercury Air Toxic Standards (MATS) rule is a significant regulation finalized by the U.S. Environmental Protection Agency in 2011 that impacted 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 good 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 (Scott, 2019). Other environmental regulations during this time which might have impacted the profitability of coal power plants include the Cross-State Air Pollution Rule, and regional policies like Renewable Portfolio Standards and the Regional Greenhouse Gas Initiative.

Finally, during this same time there was a decline in labor productivity at coal mines, leading to coal mine closures (Jordan, Lange, and Linn, 2018). This could have increased the price of coal and made coal power plants less profitable.

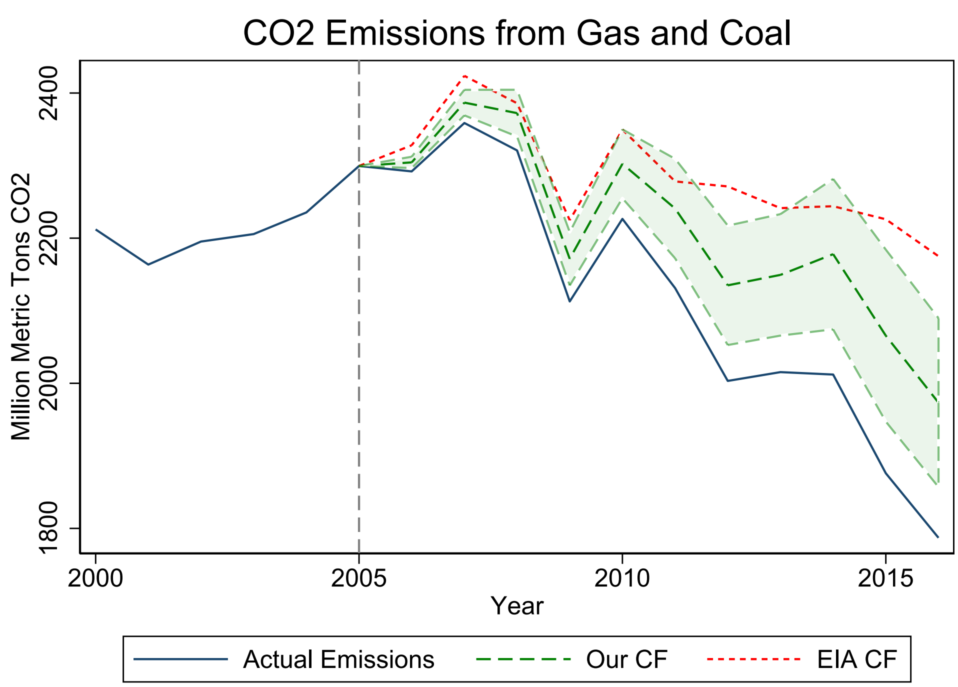
8 The Benefits *and* Costs of Shale Gas Production

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

$$CO_2emissions_{it} = \eta_1 \cdot gas\ delivered_{it} + \eta_2 \cdot production_{it} + \gamma_i + \delta_t + \varepsilon_{it} \tag{8}$$

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 8 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 8: 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. At a social cost of carbon equal to \$47 per metric ton, this counterfactual suggests reductions in environmental damages from CO_2 equal to \$5 billion per year, on average, between 2006 and 2016. By 2016, this estimate rises to nearly \$9 billion a year in abated greenhouse gases. 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 counterfactual 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."[23] 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."[24] 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 counterfactual 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, however, the reduction is not as large 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.

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

[23] 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.

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

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 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 negated from leaks during the production and transportation process because methane—the main component of natural gas—is 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 terms of reduced greenhouse gas emissions per bcf/day, equal to the marginal costs of production from increased methane leakage, 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 from one bcf/day of natural gas 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 of Equation 8, used to generate Figure 8. 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).[25] We use a baseline greenhouse gas global warming 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. This estimate is lower than existing technology-based estimates of 5 percent (Farquharson et al., 2017) and up to 9.9 percent (Hausfather, 2015).[26] Comparing this result to estimates of

[25] 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`.

[26] Alvarez et al. (2012) find a break-even leakage rate of 3.2 percent comparing the emissions from a new

actual leaks yields favorable results for natural gas production. The EPA currently estimates the methane leak rate to be around 1.4 percent.[27] 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 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 of 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.

9 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 were 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 Revolu-

efficient coal plant burning low-gassy coal and a new natural gas plant. They main distinction in their analysis is the use of a technology warming potential (TWP) instead of a global warming potential (GWP) factor. A TWP factor considers the instantaneous warming potential of methane instead of the 100 year time window.

[27] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2016

tion 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 an upper bound break even leakage value slightly above current estimates of leakage.

Overall, our results highlight the long run substitution of technologies to generate electricity in response to a technology based 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.

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Online Appendix

A Robustness of Results

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 6. 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.[28] Columns 5 and 6 consider the opposite, and excludes states that have the highest wind potential.[29] 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 7. 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.

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

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

Table 6: 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 7: 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.