

Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits[†]

By CATHERINE HAUSMAN*

Accelerated investment in electricity transmission could reduce total costs and enhance renewable integration. I document static allocative inefficiencies induced by incomplete market integration in 2 major US markets; these have risen over time and totaled \$2 billion in 2022. I also argue that estimating firm-level impacts is important, as incumbents may have the power to block new lines and other reforms. I show that 4 firms would have experienced a collective \$1.3 billion drop in net revenues in 2022 had the market been integrated, and there are reports of some of these firms blocking transmission projects. (JEL D22, D24, L13, L94, Q42, Q48)

Market integration lowers aggregate production costs and brings gains from trade. This is especially true for electricity markets, where supply costs can be quite convex and where spatial integration can substitute for a lack of widespread storage. Moreover, grid integration—high-voltage transmission lines—is widely believed to be a key part of decarbonization strategy (Joskow 2021; National Academies of Sciences, Engineering, and Medicine 2021). Indeed, some scenarios have called for tripling the capacity of the US grid by 2050 (Davis, Hausman, and Rose 2023).

The reason transmission may be particularly important in a transition toward decarbonization is that the grid of today is not spatially matched to the needs of a near-term decarbonized economy. Renewable resources like wind and solar are located in parts of the country that historically were not large sources of generation, and they are distant from most urban centers. New transmission lines have not kept up with these new sources of generation, and as a result, renewable energy gets “curtailed” (dumped) even at times when more expensive fossil plants are running in other regions. Concurrently, wholesale electricity prices have been low in renewable-rich regions, even though prices remain high in other regions (Seel et al. 2021), weakening incentives for new renewable investment.

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I study two major wholesale electricity markets in the heart of the United States: the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). Combined, these markets cover a renewable-rich swath of the windy Midwest, as well as demand centers stretching from Minneapolis and Detroit to New Orleans. I construct supply curves under counterfactuals with and without constraints on trade across regions, calculating the allocative inefficiencies caused by inadequate market integration. I also construct counterfactuals where the alleviation of constraints means that wind is no longer curtailed.¹

I find that in the recent past, constraints on electricity trade across regions were not particularly costly, with static allocative inefficiencies averaging \$400 to \$500 million per year over the 2016–2020 period.² However, the costs of these constraints have been rising, totaling more than \$2 billion in 2022. The increase over time has come from both rising natural gas prices through 2022 (which rotate the supply curve for wholesale electricity) and rising curtailments. I discuss, in light of this, what conditions in other regions and time periods would be expected to lead to high allocative inefficiencies. Moreover, as I discuss below, there are additional costs on top of the \$2 billion: dynamic allocative inefficiencies as well as reliability value.³

To further examine the causes of the estimated allocative inefficiencies, I next examine the observed behavior of individual power plants in these markets. I document that power plants tend to be dispatched in response to shocks within their own market (i.e., MISO plants in response to MISO demand). I also find that plants tend to be dispatched in response to demand shocks in their own *subregion* of their market. I find an especially striking divide between the Southern part of MISO (the Gulf Coast) and the Northern and Central parts (the Great Lakes).

It is of course possible that the \$2 billion in allocative inefficiencies I document for 2022 are socially optimal, if the cost of building new transmission lines across regions is very high.⁴ However, many grid observers have argued that the transmission planning, siting, and permitting processes in the United States do not lead to socially optimal investments, in particular for long-distance lines crossing regions. Davis, Hausman, and Rose (2023) point to myriad roadblocks, ranging from NIMBY-ism to disagreements over who pays for new lines.

To examine one potential source of transmission planning failures, I turn to empirical estimation of the potential firm-level gains and losses from market integration. While gains from trade in the *aggregate* are to be expected, it is also to be expected that some agents will lose—in particular, incumbent generators in

¹I do not directly distinguish between physical and institutional constraints (such as procedures governing the trade of electricity across regional markets). Much of the related literature has emphasized physical constraints, known to be a barrier to market integration, but below, I also discuss the role of institutional constraints.

²Dollar values throughout are reported in 2023 US dollars; I deflate using the CPI (OECD 2024).

³There are three dimensions to dynamic allocative inefficiencies. Gonzales, Ito, and Reguant (2023) shows that wind *entry* decisions are impacted by transmission constraints. Johnston, Yifei, and Yang (2023) investigate how a separate kind of transmission planning problem—the delays new generators face in obtaining interconnections—impacts renewable development. And finally, transmission constraints may impact retirement decisions of existing generators.

⁴I do not perform a cost-benefit analysis of new transmission in this paper, as I do not observe the full social costs of new transmission lines nor the scale of new investment that would be needed to remove all congestion. Engineering papers evaluating the optimal level of transmission under various assumptions include Brown and Botterud (2021); Princeton (2021); Williams et al. (2021); Bloom et al. (2021).

high-cost regions.⁵ There is of course nothing problematic about these losses for overall social welfare, but understanding which power plants, which regions, and which firms stand to lose can point toward political economy barriers.

I next show that the rise in wind energy in recent years has decreased net revenues for fossil incumbents—but crucially, by less than it would have had the market been fully integrated. That is, fossil incumbents have been partially protected from new competitors by a lack of transmission. Second, I show that the overall effect on incumbents masks important heterogeneity. There is a pronounced regional pattern to which incumbents would lose the most from integration, with firms in South MISO—an area known for inadequate connections to nearby regions—standing to lose the most.

Finally, I show that the potential losses to net revenues are very large for some firms. The four firms with the most to lose would have earned a combined \$1.3 billion less in net revenues in 2022. The majority of firms in my sample are rate of return regulated, and below, I discuss how net revenues are related to profits for these firms.

Not surprisingly, the two firms (in fact, two subsidiaries of the same firm) with the most to lose are in the Southern MISO region. Moreover, these two firms have been accused for decades of blocking new transmission lines. The tactics they have been accused of range from preventing competitors from accessing the firm's transmission network, to slow-walking the market-wide transmission planning process, to hiring a consultant to pose as a concerned customer in public hearings.

A gap in the empirical literature on electricity market integration is documentation of the magnitude of gains and losses to individual incumbent firms. Numerous papers cite this problem qualitatively (Hirst and Kirby 2001; Hogan 2018; Wolak 2020; Cicala 2021; Joskow 2021; Davis, Hausman, and Rose 2023), but empirical estimates are rarely reported.⁶ This is of particular importance given claims in the literature that losers may be holding up the transmission planning process. If the allocative inefficiencies that are becoming widely documented are a result of the planning process in the United States, then understanding incentives for firms to block market integration is of policy relevance.

The paper most directly related to my analysis is Gonzales, Ito, and Reguant (2023), which conducts a thorough examination of the role of transmission expansion in both the short-run dispatch and long-run investment decisions of the Chilean electricity market. Of most relevance for what I do, that paper shows how allocative inefficiencies arise as a result of transmission bottlenecks, and how these are exacerbated by renewables curtailments (in this case, solar). Another paper considering the dynamic relationship between renewables and the transmission grid is Johnston, Yifei, and Yang (2023), which looks at interconnections—the transmission lines specifically needed for new renewables hookups—in another major US market. My

⁵ As I discuss below, other losers include consumers in some regions, who would see rising prices. Winners include generators currently experiencing low prices, who would be able to export their power to locations that are currently load pockets (areas with high demand and an insufficient ability to import power). Consumers in load pockets would also win. And finally, new renewables entrants could win as prices rise in windy areas, e.g., the Great Plains.

⁶ There are papers that estimate the impacts of transmission constraints (or their alleviation) on the revenues of wind and solar sources—particularly *new* wind and solar—(Gonzales, Ito, and Reguant 2023; Johnston, Yifei, and Yang 2023; Kemp et al. 2023), but they generally do not investigate the impacts on incumbent fossil generators.

paper complements their work by focusing on the across-region constraints impacting existing generators.

Other related papers on the interaction of renewable generation and transmission network expansion include Jorgenson, Mai, and Brinkman (2017); Qiu (2020); Brown and Botterud (2021); Fell, Kaffine, and Novan (2021); Bloom et al. (2021); Doshi (2024); LaRiviere and Lyu (2022); Yang (2022); Kemp et al. (2023); and Lamp and Samano (2023). These papers study a variety of markets (Texas, Germany, and more) using a variety of modeling techniques. Taken as a whole, these papers show how transmission and renewable generation can be complements. This relates to evidence on the spatial misallocation of renewables investments in the United States to date (Callaway, Fowlie, and McCormick 2018; Sexton et al. 2021).

There is also a broader literature on allocative inefficiencies arising from transmission constraints in electricity markets even aside from their interaction with renewable generation. Some of these papers emphasize how opportunities to exercise market power are increased in the presence of transmission constraints (Wolak 2015; Davis and Hausman 2016; Ryan 2021), a point I return to below. The transmission network also has an important role in enhancing grid reliability (Borenstein, Bushnell, and Mansur 2023). And there is a broader literature on the regional integration of electricity markets, relating to market design rather than to physical transmission constraints (Mansur and White 2012; Cicala 2022).

Finally, my results relate to ongoing policy discussions about the state of the transmission network (and the fragmentation of regional electricity markets more broadly) and how best to manage the grid (Department of Energy 2023b). These complex issues span economics, law, and engineering. I conclude the paper by tying my results back to these discussions.

The paper proceeds as follows. In Section I, I provide brief contextual background. Section II summarizes the data sources I use. Section III summarizes the methods and results on allocative inefficiencies. Section IV explores net revenue impacts for incumbent firms. Section V shows various robustness checks, and Section VI concludes.

I. Background

I study two US electricity markets, the Southwest Power Pool and the Midcontinent Independent System Operator. Each is a nonprofit entity (an “Independent System Operator,” or ISO) responsible for operating the electricity grid within their footprints: matching supply and demand offers, as well as ensuring grid reliability.

SPP’s members are in 15 states, roughly covering the Great Plains region from Montana to Texas.⁷ MISO also covers 15 states (roughly, from North Dakota to Michigan and south to Louisiana) and 1 Canadian province.⁸ Some states are split between both SPP and MISO, but one can broadly think of SPP as covering the

⁷SPP’s members are in Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; some (such as Colorado and Wyoming) are only partly covered by SPP.

⁸The states covered are Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin; some (such as Montana and Texas) are only partly covered by MISO.

Great Plains and MISO as being more to the east (the Great Lakes and the Gulf Coast).

Both SPP and MISO are part of the Eastern Interconnection. The US electricity grid is physically divided into three such interconnections: one in the Western half of the country, one in the Eastern half, and one covering most of Texas. There is almost no transmission between the three grids, a legacy of the way the grid originally developed in the United States.

Both SPP and MISO have independent market monitors, who evaluate the functioning of each market, including both reliability metrics and whether generators appear to be exercising market power. Annual reports from both market monitors covering my sample period indicate competitive generation markets, as I describe below.

The generation mix of both MISO and SPP includes a mix of fossil power plants (coal and natural gas), nuclear, and a growing supply of wind (particularly in SPP). Both regions have small quantities of hydro, solar, and other units (e.g., thermal plants fueled by solid waste). Summary statistics and a map are provided in the Supplemental Appendix. Most notably, wind generation is high (10 percent of generation in MISO and 30 percent in SPP over my sample), growing, and in different locations than conventional generators. Wind generation nearly doubled in MISO Central/North and SPP from 2016–2017 to 2021–2022. In contrast, MISO South has no wind generation. These changes over time suggest that the transmission network is not spatially suited to new market conditions. Wind generation increased by more than 10,000 MWh in the average hour in MISO Central/North and SPP in aggregate, and consumption changes over this time period did not offset this differential increase in supply.⁹

MISO and SPP have each seen new transmission capacity added during this time frame but with limitations (Midcontinent Independent System Operator 2024; Southwest Power Pool 2016–2023). As tables in the Supplemental Appendix show, many transmission upgrades have been reported by the two ISOs over the 2016–2022 period, across a broad range of states. However, these projects were generally not intended to reduce generation costs related to congestion; the majority were aimed at addressing reliability needs, especially local and regional reliability.¹⁰ Moreover, only 3 percent crossed state boundaries, and not a single project is listed as connecting MISO South with MISO North.

The data on MISO and SPP transmission upgrades in the Supplemental Appendix point to why pre-/postanalyses of individual large-scale transmission projects, along the lines of what is done in Fell, Kaffine, and Novan (2021); LaRiviere and Lyu (2022); and Gonzales, Ito, and Reguant (2023), are not possible in this study's context: There is no individual project on the scale of something like Texas's CREZ

⁹ Average hourly demand increased by around 680 MWh in MISO South and around 2,100 MWh in MISO Central/North plus SPP.

¹⁰ Example descriptions of local and regional reliability projects make clear that these are not long-distance, high-voltage lines: "Install 69KV Breakers"; "Construct a new 69/25kV distribution substation"; "Construct approximately 0.5 mile in and out 115 kV line"; "Uprate ... 69 kV line to 115 MVA"; and "Rebuild 3.8-mile 115 kV line."

project.^{11,12} They also raise the question of why long-distance lines are not being built on a greater scale, which my results can help answer.

This paper focuses on the kinds of transmission build-out that would improve trade between MISO and SPP as well as across regions within each of the two markets. I do not address the possibility of greater trade with, e.g., the Western or Texas interconnections, nor do I address highly localized projects. Each of these different levels involves different costs and regulatory barriers (Davis, Hausman, and Rose 2023).¹³ The level on which I focus has received attention by policymakers, in part related to the perception that interregional lines could lower generation costs but have faced regulatory and governance barriers.

Finally, in addition to physical transmission constraints, analysts have pointed to market design flaws and other institutional constraints limiting trade across ISOs. For electricity markets more generally across the United States, there have been recent calls for both physical infrastructure improvements and greater market coordination across regions (Pfeifenberger et al. 2023; Energy and Environmental Economics Inc 2024; Simeone and Rose 2024).

II. Data

I build a panel dataset on these two major US electricity markets (SPP and MISO), incorporating data from several government agencies as well as both market operators (Hausman 2025). Here, I provide a brief overview; descriptive statistics are in the Supplemental Appendix.

From the US Environmental Protection Agency's (EPA's) CEMS dataset (Environmental Protection Agency 2016–2022b), I observe hourly generation and hourly fuel use at individual thermal generating units;¹⁴ a typical power plant has between one and eight generating units.¹⁵

Also from CEMS, I observe each unit's fuel type (coal, natural gas, and oil), technology (boiler, combined cycle, or combustion turbine), and location (latitude and longitude). The majority (74 percent) of units in my sample use natural gas, 21 percent use coal, and only 5 percent use oil. From the EIA-860 survey (Energy Information Administration 2016–2022a), I observe additional characteristics of each plant: its location in MISO versus SPP, the name of its owner, and whether its

¹¹The Competitive Renewable Energy Zone (CREZ) project brought transmission expansion that better integrated windy West Texas with demand centers in the eastern part of the state (Fell, Kaffine, and Novan 2021).

¹²One could imagine leveraging the time series of these projects. However, (i) the time series of dollars spent on the projects is nearly collinear with a linear time trend; and (ii) the individual projects are each too small to yield much identifying variation, when compared to the size of the entire MISO/SPP market.

¹³In addition, utility incentives for encouraging versus blocking local transmission projects are very different than for interregional projects. Localized projects aimed at improving reliability do not subject the utility to a greater degree of competition on the generation side, in sharp contrast to longer-distance lines.

¹⁴The reported generation in the CEMS dataset is "gross" rather than "net"; the difference is generation used for in-house operations and therefore not sold on the wholesale market. To convert from gross to net generation, I follow the literature (Cicala 2022) in matching gross generation from CEMS to net generation from the Department of Energy's Energy Information Administration's EIA-923 dataset, available at the annual level (Energy Information Administration 2016–2022b). I then construct a conversion factor at the plant-by-technology level.

¹⁵The hourly EPA data are limited to generating units with a capacity of at least 25 MW; smaller units are observable only at the annual level, from a separate data source (the Energy Information Administration's EIA-923 survey or the EPA's eGRID dataset). However, the average capacity of a coal- or natural gas-fired unit in the United States in 2021 was 120 MW, so these unobserved units are quite small; they make up only around 1 percent of total coal and natural gas generation, according to the EPA's eGRID 2021 dataset.

owner is an investor-owned utility or a merchant generator. Two-thirds of the units I observe are in MISO, which has a larger footprint than SPP. The majority of units in my sample are operated by investor-owned utilities.

From the CEMS hourly generation and fuel use, I calculate each unit's heat rate, a measure of how efficiently it converts fuel into electricity (and a primary component of marginal cost).¹⁶ I calculate each unit's capacity as the ninety-ninth percentile of observed generation. Generating units are taken offline frequently for maintenance, so I use seasonal outage rates from a market monitoring report (Potomac Economics 2022b).

The two market operators also release detailed data. From each, I observe ISO-wide hourly generation by fuel type; this is important for understanding the behavior of nuclear and renewable generation, as those fuel types are not represented in the CEMS data (Midcontinent Independent System Operator 2016–2022a; Southwest Power Pool 2016–2022a).¹⁷ I also assemble wind curtailment data from the ISOs (Midcontinent Independent System Operator 2018–2023; Southwest Power Pool 2016–2022e).¹⁸ Each ISO also reports total quantity demanded at the hourly level (called “load” in electricity markets) for various regions (Midcontinent Independent System Operator 2016–2022b; Southwest Power Pool 2016–2022b).¹⁹ From EIA's 930 dataset, I observe load in the Eastern Interconnection as a whole (Energy Information Administration 2023e).

Fuel prices are published by the EIA; I use both daily upstream prices (the Henry Hub natural gas price and the West Texas Intermediate (WTI) oil price) and monthly downstream prices (the average fuel price paid by power plants for coal, natural gas, and oil) (Energy Information Administration 2023d,b,a). Finally, daily temperatures are published by NOAA (National Oceanic and Atmospheric Administration 2016–2022), and wind speeds by Environmental Protection Agency (2016–2022a), and FIPS codes by Environmental Protection Agency (2014).

III. Allocative Inefficiencies

A. Constructing Marginal Cost Curves

To construct market-wide marginal cost curves, I first construct the marginal cost mc of each thermal generating unit i in each hour t as follows:

$$(1) \quad mc_{i,t} = fp_t \cdot hr_i + om_i + ec_{i,t},$$

¹⁶I generally allow heat rates to vary across years at the unit level, to reflect both unit degradation and capital improvements. Three plants have anomalous heat rates in just one or two years; for these, I use the sample-wide unit-level average.

¹⁷MISO but not SPP also releases hourly generation by fuel type at a broad regional level (North, Central, South) which I leverage later when examining counterfactual revenues.

¹⁸Most ISOs across the United States report wind and/or solar curtailments. These are generally measured as the difference between actual generation and forecasted generation (for a very short-term forecast), conditional on the unit experiencing something like manual dispatch or a “follow flag.” SPP's measurement, for instance, is described at <https://portal.spp.org/pages/ver-curtailments>. From SPP, I observe hourly wind quantity curtailed. MISO does not make hourly curtailment data available, but I assemble daily curtailment data, separated into peak and off-peak periods, for December 2019 through December 2022 from the slide decks published for MISO's monthly Informational Forum web presentations.

¹⁹MISO reports load across three broad regions (North, Central, and South). SPP reports more disaggregated regions—more than a dozen—which I aggregate to three broad regions to parallel the regional definitions I have for MISO.

where fp is the fuel price in each hour (in dollars per mmBtu), hr is the heat rate of each unit (in mmBtu per MWh), om is the unit's variable operating and maintenance costs (in dollars per MWh), and ec is the environmental compliance cost (in dollars per MWh).

Recall that the Energy Information Administration publishes both monthly data on average prices paid for fuel by power plants and daily upstream fuel prices (Henry Hub for natural gas and WTI for oil). It is important to capture both this daily variation in natural gas and oil prices as well as the markup, so I construct fuel prices as the upstream price (varying daily) plus an annual state-level markup (the difference between the upstream and downstream prices reported by EIA). Coal prices have little variation across days within a month, so I simply use EIA's monthly data on average price paid by power plants. I assume technology-specific om values from Energy Information Administration (2019) where possible, and otherwise from Energy Information Administration (2022, 2023c).

An additional, albeit minor, marginal cost for most units in my sample is the cost paid to purchase permits to cover pollution emissions. Units in these states are covered by EPA cap-and-trade programs for sulfur dioxide and nitrogen oxides emissions. I observe hourly emissions from the EPA CEMS dataset and annual permit prices from the EPA's Power Sector Programs Progress Reports (Environmental Protection Agency 2016, 2017-2021, 2022, 2016-2022c), from which I calculate total environmental compliance costs.²⁰ These costs have at some points in US history been very high, but for my sample, this increases marginal cost by less than 1 percent on average.

Summing across the three components of marginal cost, I obtain marginal costs, in dollars per MWh, that are generally in line with the literature. A small number of values are implausible (e.g., because I estimate a very high heat rate at some units), so I winsorize marginal costs at the first and ninety-ninth percentiles.

My primary sample contains only the coal, natural gas, and oil power plants for which marginal costs are well-known. I drop the small number of thermal units with fuel types such as wood and municipal solid waste; these make up less than 1 percent of CEMS generation. As my primary analysis constructs counterfactuals regarding changing the dispatch of thermal units, this is akin to assuming that the behavior of wood and waste units does not change in my counterfactuals. Similarly, I drop commercial and industrial and cogeneration units (e.g., generating units located at chemical plants, hospitals, and universities); again, marginal costs at these units are not clear, and dropping them is simply assuming that they would not respond to market changes.

Marginal costs for renewables and nuclear generation do not depend on heat rates and permit prices. Following the literature, I assume that renewables (wind, solar, and hydro) have zero marginal cost.²¹ For nuclear units, I assume a marginal cost based

²⁰Specifically, I calculate the annual emissions rate for each unit, in tons of pollutant per MWh of generation; I multiply this by the permit cost, which is in dollars per ton of pollutant.

²¹Most papers on electricity markets in the West must make more complex assumptions about hydroelectric behavior, as dams allow operators to store some of their capacity for when prices are high. Modeling this correctly is important in the West, where hydro is a substantial source of electricity; this is much less true in MISO and SPP, where hydro is relatively small. According to eGRID, hydro provided only 2 percent of generation across MISO and SPP in 2021, but it provided more than 30 percent of generation across the West Coast (California, Oregon, and Washington).

on the average operating expenses for nuclear units reported in Energy Information Administration (2023c).²² I construct capacity for renewables and nuclear as follows. Maximum generation for renewables varies across hours, depending on weather (e.g., how windy it was that hour); I construct hourly maximum generation as observed generation for each fuel type, plus the quantity curtailed. I also assume that, because of their operational constraints, nuclear units will not respond to short-term fluctuations in wholesale prices (Davis and Hausman 2016), and thus, I fix their generation at what I empirically observe in each hour.

The other variable needed for each thermal generating unit is its maximum capacity. As described in the data section, I use empirically observed capacities. However, I must also apply outages, as units go offline for both planned and unplanned maintenance. As explained in detail in the Supplemental Appendix, I derate capacity across all units to account for planned outages, and I additionally stochastically remove units from the supply curve to account for unplanned outages. For computational simplicity, results reported in the main text use independent draws across each unit-by-hour observation. In the Supplemental Appendix, I perform Monte Carlo simulations with each unplanned outage lasting two weeks, and results are similar.

With hourly marginal costs and annual capacities, I can construct market-wide marginal cost curves.²³ For my first counterfactual, I use a least-cost dispatch framework: I rank the units by their marginal cost, then dispatch units until demand is met, where demand is defined as the total quantity generated in the real world in hour t across all generators. That is, in each hour t , I choose quantities g generated at each unit i to minimize the total cost of production, in order to meet market-wide demand, subject to a capacity (C) constraint at each unit:

$$(2) \quad \min_{g_{i,t}} \sum_{i \in \{1,2,\dots,I\}} mc_{i,t} g_{i,t} ,$$

subject to

$$\sum_{i \in \{1,2,\dots,I\}} g_{i,t} = demand_t; \quad g_{i,t} \leq C_{i,t} \quad \forall i.$$

This approach is widely used in the literature in both economics and engineering (Borenstein, Bushnell, and Wolak 2002; Deetjen and Azevedo 2019; Mills et al. 2021; Cicala 2022).²⁴ A limitation of this approach is that it ignores transmission constraints and various technical constraints of generating units themselves (ramping

²²Table 8.4 of Energy Information Administration (2023c) reports average fuel costs of around \$8/MWh for my sample period. Operations and maintenance (O&M) costs average \$20/MWh; I assume that half of these are fixed O&M and half are variable O&M; that is, half are marginal to generation. This gives a marginal cost estimate of \$18/MWh, comparable to the California-specific estimate in Davis and Hausman (2016).

²³Some empirical approaches would leverage equilibrium price data rather than construct supply curves. I do not do so for two reasons. First, to calculate allocative inefficiencies, I need to integrate under the entire supply curve in each hour, whereas hourly prices give me a single point on the supply curve. Second, and relatedly, electricity cost curves are highly nonlinear at any point in time, and they vary substantially across time with fuel prices and wind availability; thus, one cannot simply assume an elasticity to back out the cost curve from a given observed equilibrium price and quantity.

²⁴Note the terminology used varies; for instance, Mills et al. (2021, p. 1) refers to this approach as a “fundamental supply curve model.”

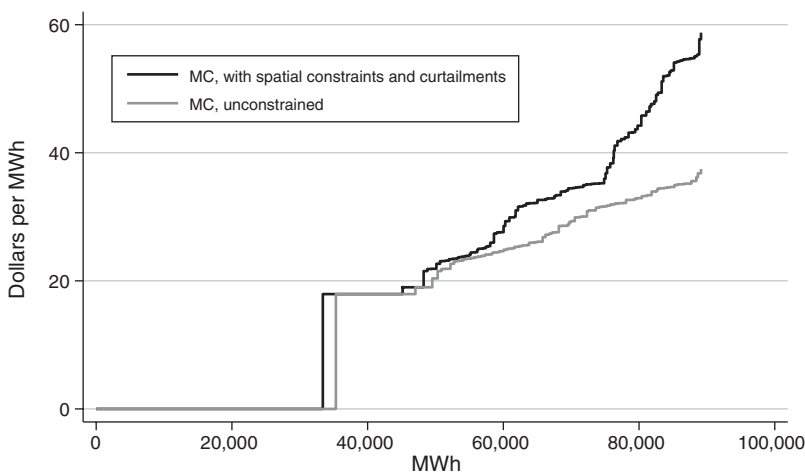


FIGURE 1. MARGINAL COSTS OF DISPATCHED GENERATORS, WITH AND WITHOUT SPATIAL CONSTRAINTS
(ONE EXAMPLE HOUR IN 2022)

Notes: This figure shows two constructed marginal cost curves for a representative hour in 2022, for the entire SPP and MISO market, up to the quantity demanded in that hour. The gray line shows the marginal cost curve for least-cost dispatch, with no restrictions on electricity flows across space and with no curtailment on the dispatch of wind. In contrast, the black line constrains quantities generated within a North American Electric Reliability Corporation subregion by ISO to the quantity observed in the actual data (to approximate transmission constraints) and curtails wind generation at the level observed in the actual data. Zero marginal cost resources are largely wind but also include hydro and solar generation. Nuclear generation is assumed to have a marginal cost of \$18/MWh. The remaining units are powered by coal and natural gas, with differences in marginal cost reflecting differences in heat rates and fuel type. The date and hour are chosen because they have fuel costs, quantity demanded, and quantity curtailed close to the sample average for 2022. Additional date-hour combinations (with alternative fuel costs, quantity demanded, and quantity curtailed) are shown in the Supplemental Appendix.

costs and other dynamic considerations, and minimum dispatch constraints). Below, I augment with additional counterfactuals to incorporate additional constraints.

The marginal costs of dispatched generators are shown with a gray line in Figure 1. I choose a sample hour that is typical in terms of total quantity demanded, fuel prices, and wind quantity curtailed for 2022; additional sample hours typical of different market conditions are shown in the Supplemental Appendix. For this sample hour, 34,000 MWh of generation are provided by zero-cost renewables; an additional 13,000 MWh by nuclear; and the remaining 42,000 MWh by a mix of thermal generating units, primarily coal boilers. Across all hours in my sample, thermal generation is provided by a mix of fuel and technology types, where marginal cost varies across units because of varying heat rates and fuel prices.

B. Modeling Spatial Constraints

For the second counterfactual, I assume that the system is constrained in two ways. First, I incorporate regional spatial constraints, modeled in a reduced-form way as follows. I assign each generating unit to a North American Electric Reliability Corporation (NERC) subregion as reported in the eGRID dataset (see Supplemental Appendix for map), and to MISO versus SPP as reported in EIA-860

(Environmental Protection Agency 2016–2021; Energy Information Administration 2016–2022a). I define subregions as the interaction between these two variables, yielding 10 subregions overall.²⁵ NERC is a nonprofit organization that oversees electric grid reliability in the United States, Canada, and part of Mexico, and it monitors reliability across approximately two dozen subregions. As noted in the background section, I focus on this level of geographic constraint because transmission projects of roughly this magnitude (e.g., connecting two or three states, or crossing the MISO/SPP seam) have been the focus of much policy discussion in recent years (Department of Energy 2023b, 2024).²⁶

I infer constraints across subregions at the hourly level by calculating the total quantity supplied by thermal generating units in each hour in each subregion using the CEMS generation data. As I dispatch units using the least-cost dispatch algorithm described above, I constrain total generation in each subregion in each hour to what I empirically observe. That is, I force each subregion to generate no more than what was actually generated in the real world.²⁷

The optimization problem is thus

$$(3) \quad \min_{g_{i,t}} \sum_{i \in \{1,2,\dots,I\}} mc_{i,t} g_{i,t} ,$$

subject to

$$\sum_{i \in \{1,2,\dots,I_r\}} g_{i,t} = obs_gen_{r,t} \quad \forall r \in R; \quad g_{i,t} \leq C_{i,t} \quad \forall i,$$

where the total generation constraint must be met *within* each region r and where the total generation constraint is defined as the region-wide observed generation in the real world in hour t : $obs_gen = \sum_{i \in \{1,2,\dots,I_r\}} g_{i,t}^{observed}$. Thus, the *flows* of generation across regions cannot be greater in my model than whatever they were in the real market in hour t , where the latter was a function of the (unobserved) physical grid, including individual transmission line capacity constraints and time-varying weather shocks that impact transmission line performance. In two robustness checks, I vary the geographical boundaries of the regions.

This counterfactual also assumes that wind generation is curtailed because of transmission constraints, following what I see in the real world. Whereas the first counterfactual constructs wind capacity as equal to observed generation in each hour plus observed quantity curtailed in each hour, this second counterfactual constructs wind capacity as equal to only observed generation in each hour.

²⁵I use the mapping from power plants to NERC subregions available from the Environmental Protection Agency's eGRID database. This yields a very small number of units in ERCT, SRSO, and SRTV, three NERC subregions that primarily do not lie in MISO or SPP (one plant in ERCT, two in SRSO, and four in SRTV). I assign these plants to SPSO, SRMV, and RFCW, respectively, so as to not overstate how binding spatial constraints might be to the ERCT, SRSO, and SRTV regions.

²⁶An additional benefit of using NERC-by-ISO regions for the main specification is that it roughly corresponds to price hubs at the ISO level, so interpretation as a geographic area of interest for market outcomes makes sense; and my modeled equilibrium prices can be compared to ISO-reported prices (see Supplemental Appendix). Nonetheless, robustness checks, below, model both a broader and a narrower set of geographic constraints for comparison.

²⁷In a small number of hours, my model predicts that too little capacity is available in some regions. This is because of the outage patterns I impose. In these hours, I force all units to operate slightly above their capacity. This changes generation by more than 10 MWh for fewer than 0.1 percent of observations.

Ideally, one would model the actual topology of transmission constraints, but that is not feasible here for several reasons. Accurate modeling of the transmission network would require knowing the physical topology of the grid, including not only line locations but also line ratings (related to the capacity of each line); detailed information on this topology is not publicly available. Furthermore, modeling the flow of electrons across the network is complicated. One should not picture something like a pipeline network for natural gas or water, in which one would simply need to observe quantities flowing in and out of the pipelines. Instead, electron flow across a network is governed by complex laws of physics (Joskow 2012; Borenstein, Bushnell, and Mansur 2023). Moreover, congestion is constantly changing—both in where it impacts the grid and in how binding it is—as demand, generation, and weather change, and the inputs to this complex process are not all observable.

Many existing papers on transmission study simple two-node problems; California and Chile each predominantly have a North–South transmission constraint, and pre-CREZ Texas had a West–East constraint. In contrast, my setting features a complex set of interregional constraints. My reduced-form model provides a reasonable approximation that uses publicly available data, that can be calculated for multiple regions in every hour using observable data, and that is computationally not too burdensome.

The marginal costs of dispatched generators for this second counterfactual are shown with the black line in Figure 1. Zero-cost generation shifts inward, by the quantity curtailed. Nuclear units are unaffected, by construction.²⁸ Also, some higher-cost thermal units must be dispatched because of the regional constraints.

C. Calculating Allocative Inefficiencies

The wedge between the black and gray lines in Figure 1 represents the additional costs required to generate electricity that are induced by regional constraints and the need to curtail wind. By calculating the area between the two curves in each hour, I can construct a time series of the allocative inefficiencies induced by transmission constraints and wind curtailments. That is, for each hour t , I calculate $\sum_i mc_{i,t} g_{i,t}^\dagger - \sum_i mc_{i,t} g_{i,t}^*$, where $g_{i,t}^\dagger$ are equilibrium quantities from equation (3) and $g_{i,t}^*$ are equilibrium quantities from equation (2).

Figure 2 shows this time series, aggregated to the monthly level. I focus on 2020 through 2022, the period for which wind curtailments data are available from MISO; a time series with inferred wind curtailments for 2016–2020 is shown in the Supplemental Appendix.

Figure 2 shows that spatial and curtailment-related allocative inefficiencies have been rising over time for the MISO and SPP markets. This is a combination of increasing natural gas prices and increasing curtailments—the latter induced by a growing spatial mismatch between supply and demand. By 2022, the average monthly allocative inefficiencies total \$190 million, translating to more than \$2 billion for 2022. Table 1 shows an annual summary of the allocative inefficiency.

²⁸ As described above, it is technologically difficult and expensive to ramp nuclear units up and down; as a result, nuclear units are very rarely curtailed. They are occasionally forced to limit their generation because of safety concerns, which I do not model as part of this counterfactual.

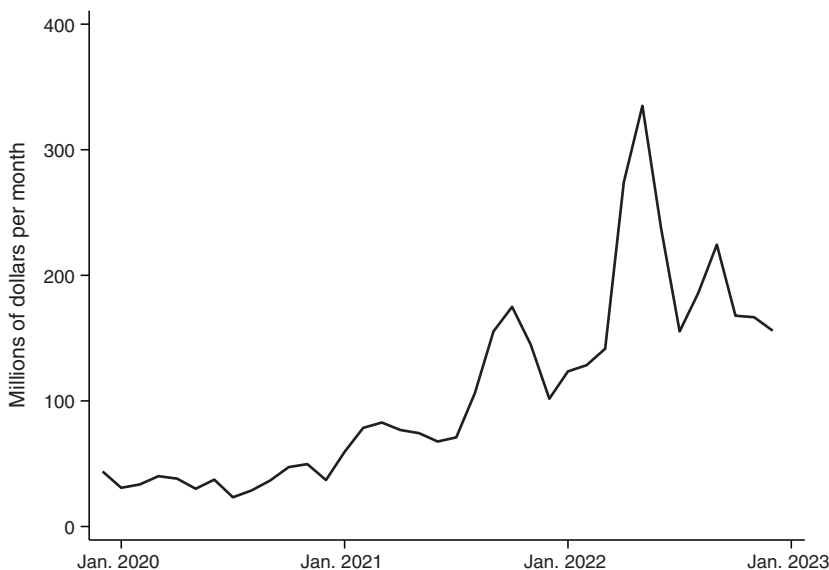


FIGURE 2. ADDITIONAL GENERATION COSTS FROM SPATIAL CONSTRAINTS

Notes: This figure shows the monthly generation costs in MISO and SPP that arise from spatial constraints and associated renewables curtailments. Constraints are modeled at the NERC subregion by ISO level and so do not include within-subregion transmission constraints. Costs have risen over time from a combination of increasing natural gas prices and increasing curtailments—the latter a result of spatial mismatch between supply and demand. Robustness checks are shown in the Supplemental Appendix. Additional time series, holding various factors constant, are also shown in the Supplemental Appendix.

TABLE 1—ANNUAL ALLOCATIVE INEFFICIENCIES

Annual cost, billion dollars	2016–2020	2021	2022
Total	0.39 to 0.50	1.19	2.30
Across-ISO constraints	0.07	0.16	0.24
Within-ISO constraints	0.28	0.70	1.39
Curtailments	0.03 to 0.14	0.33	0.66
Within-SPP constraints	0.10	0.23	0.30
Within-MISO constraints	0.19	0.47	1.09

Notes: This table shows the average annual generation costs in MISO and SPP stemming from spatial constraints and renewables curtailments. Matching Figure 2, the table shows the increase after 2021 in these costs. The next three rows decompose the 2022 cost into three factors: renewables curtailments, constraints between MISO and SPP, and constraints across NERC subregions within MISO and SPP. The bottom two rows separate within-ISO constraints into those within MISO and those within SPP.

For the sample as a whole, annual allocative inefficiencies total \$0.8 to \$0.9 billion (the range comes from what one assumes about MISO wind curtailments for the 2016–2019 period). However, this average masks a large difference between the 2016–2020 period, with an annual average of \$0.4 to \$0.5 billion, and the 2021–2022 period, with annual inefficiencies of \$1.19 billion in 2021 and \$2.30 billion in 2022.

This stark difference in 2022 costs is primarily related to increasing natural gas costs and a growing spatial mismatch between supply and demand, as I show in two

different ways. First, I regress the hourly inefficiency, that is, additional cost c , on total demand d across the two ISOs, potential wind generation w , and fuel prices (natural gas n and oil o):

$$(4) \quad c_t = \beta_1 d_t + \beta_2 w_t + \beta_3 n_t + \beta_4 o_t + \mathbf{X}'_t \Theta + \varepsilon_t.$$

In the MISO/SPP context, increases in wind generation have not been spatially matched to demand. They have thus led to increases in curtailments, particularly in windy hours when capacity factors of wind generators are high.

I begin with *potential* wind generation, the sum of wind generation that made it to market and wind that was curtailed, on the right-hand side because it is exogenous (determined by weather rather than market activities); below, I separately consider wind that was sold versus curtailed. Following the literature, I include controls \mathbf{X} for weather (heating and cooling degree days) and various time effects (month of sample, day of week, hour of day). Coal prices are measured at the monthly level and are thus absorbed by the month of sample effects.²⁹ Overall, this regression is designed to describe how short-run shocks to demand, fuel prices, and wind generation correspond to allocative inefficiencies; it does not capture the extent to which medium- to long-run changes in the right-hand-side variables lead to changes in investment decisions and therefore dynamic or long-run changes to allocative inefficiencies.

Table 2 shows the results; alternative specifications are shown in the Supplemental Appendix. Not surprisingly, the wedge is larger when demand is higher; the wedge is also larger when natural gas prices are higher.³⁰ Each additional MWh of demand implies \$0.68 in allocative inefficiencies in an hour. Going from the twenty-fifth percentile to the seventy-fifth percentile of demand would imply an increase in inefficiency of \$14,000 per hour (relative to an average hourly allocative inefficiency of \$98,000). Increasing natural gas prices by \$1 per mmBtu is correlated with a short-term increase in inefficiencies of around \$21,000 in an hour; note Henry Hub has a standard deviation of around \$1.7 per mmBtu over this time period.

The wedge is larger at times when potential wind generation is higher; as wind capacity has entered the market, it has led to an increase in spatial mismatch between supply and demand. Interpretation of this coefficient is important: Wind generation of course lowers the marginal cost of producing electricity (see Figure 1), but it lowers it by less than it would if the grid were fully integrated, so the allocative inefficiency increases. The implication is not that wind is not good for lowering costs, but rather that transmission is a complement to wind in the SPP/MISO markets since wind generation is concentrated in low-population areas like Iowa and Kansas (see the map in the Supplemental Appendix).

Combined, these results (column 1) point to the conditions under which we might expect regional constraints to be costly in other regions and time periods. Positive demand shocks (for instance, from new industrial growth or from increased electrification of the transportation sector) would be expected to increase allocative inefficiencies. And while natural gas prices fell in 2023, future natural gas

²⁹In addition, coal prices are very stable over this time period and thus not likely to contribute to changes in the wedge over the sample.

³⁰Oil generation is very small, so oil prices do not materially impact the wedge.

TABLE 2—ALLOCATIVE INEFFICIENCIES INCREASE AS WIND CURTAILMENTS INCREASE

	(1)	(2)	(3)	(4)
Demand	0.68 (0.086)	0.69 (0.079)	0.66 (0.089)	0.68 (0.082)
Natural gas price	20,726.7 (2,894.8)	20,643.9 (3,495.6)	26,789.7 (2,742.8)	28,261.0 (2,620.0)
Oil price	216.4 (254.6)	380.6 (207.8)	204.3 (252.6)	424.5 (211.9)
Wind generation + curtailments	4.19 (0.22)		4.51 (0.28)	
Wind generation		1.09 (0.12)		-0.14 (0.17)
Wind curtailments		35.9 (1.16)		46.6 (2.44)
Observations	61,266	61,266	56,854	56,854
R^2	0.79	0.86	0.34	0.53
K-P F -stat			170	17

Notes: The unit of observation is an hour. The dependent variable is the hourly allocative inefficiency induced by spatial constraints. The independent variables of interest are total demand, total wind potential (generation plus curtailments), and fuel prices. Additional controls are heating and cooling degree days and time effects (month of sample, day of week, hour of day). Standard errors are clustered by sample week.

price increases—or indeed any upward rotation of the supply curve—could again increase congestion costs. Extreme weather events leading to spatially correlated plant outages would similarly increase the wedge. Finally, the increased presence of renewables in locations that historically had little power generation will lead to inefficiencies unless new transmission keeps up. Indeed, curtailments are rising in many regions of the country. Again, this does not imply that renewables themselves lead to inefficiencies, but rather that transmission is a complement to these technologies.

To expand on this point, column 2 of Table 2 breaks total wind into two variables: generation that actually made it to market and potential generation that was curtailed. The positive coefficient on wind comes almost entirely from curtailments, which in the SPP/MISO markets are primarily a function of transmission congestion. Spatial constraints that induce wind curtailments lead, over this time period, to more generation from fossil resources, implying an average increase in allocative inefficiencies of \$36 (column 2). In contrast, wind generation that does make it to market corresponds to only a modest increase in allocative inefficiencies; presumably this arises because sometimes fossil generation that is located close to wind resources cannot be used, and more expensive and more distant fossil generation takes its place.

Curtailments are a function of system conditions, not just weather, so they are not exogenous. To the extent that they are the result of a combination of slowly evolving wind capacity, of exogenous hourly wind shocks, and of slowly evolving physical transmission infrastructure, they contain quasi-exogenous variation. Nonetheless, columns 3 and 4 of Table 2 instrument for wind generation and curtailments using a vector of wind speed and capacity variables: wind speed at the hour-by-state level for each of the MISO and SPP states and wind speed interacted with wind capacity

in each state.³¹ Results are similar to the OLS results from column 2 and again, make it clear that curtailments are indicative of transmission constraints that yield allocative inefficiencies over the sample period.

Additional tables in the Supplemental Appendix explore heterogeneity in these results. In particular, the marginal effect of additional demand is especially large at high levels of demand, when the grid is more congested. Similarly, the wind effect especially matters at high levels of wind potential, when local congestion near wind sites is more likely and curtailments more common. These are not necessarily the same hours; in fact, demand and wind potential are negatively correlated ($r = -0.2$).

As another way to decompose the source of the increase in allocative inefficiencies over time, the Supplemental Appendix shows the time series of the inefficiency holding fuel prices and/or curtailments constant.³² It shows that the increase in allocative inefficiency in 2022 is a result of both changing fuel prices and rising curtailments (indicative of transmission congestion), with more of the effect coming from fuel price changes.

Low natural gas prices in recent decades had flattened the market-wide marginal cost curve for electricity. But with natural gas prices rising in 2022, the marginal cost curve rotated, and dispatching the “wrong” unit—because of something like a regional transmission constraint—became much more expensive. My sample does not include 2023 (because of lags in data availability), but natural gas prices fell in 2023, and this is likely to pull allocative inefficiencies back down.

The rise in allocative inefficiency over my sample period has important policy implications. It is clear why some policymakers and grid observers have been increasingly calling for new transmission infrastructure in recent years. The transmission network until recently basically did what it needed to: connecting thermal power plants to demand in population centers. But in a world with more renewable generation, existing transmission lines do not match the spatial distribution of generation.

Returning to Table 1, I show various decompositions of the inefficiencies within a given time period. Rows 2 and 3 show that the largest source of the 2022 inefficiencies was within-ISO constraints (\$1.39 billion), whereas inefficiencies from across-ISO constraints totaled only \$0.24 billion. The second-largest component of inefficiencies was the need to curtail wind (\$0.66 billion, row 4). With wind facing a marginal cost of essentially zero, curtailing it and having to use a fossil unit can significantly raise the costs of electricity generation.³³

³¹ Wind capacity is measured at the year level, and so its effect in *levels* is absorbed here by the month-of-sample effects.

³² In reality, curtailments in MISO and SPP are generally a function of transmission congestion, so it is not realistic to model transmission congestion as still holding while curtailments are eliminated. The thought experiment in the scenarios plotted in the figure is roughly to suppose the same quantity of wind (with the same hourly profile) had been built in the same locations where demand is served, such that it was unaffected by transmission congestion. The caveat, however, is that this hypothetical relocation of wind generation would also change the congestion patterns induced by the *noncurtailed* wind, whereas my decomposition assumes that the congestion patterns are unaffected by the relocation of wind.

³³ Decomposing into across-ISO, within-ISO, and curtailment effects is also useful if there are expansions of the transmission network that would change fossil dispatch without ameliorating all curtailments. If, for instance, 10 percent of curtailments cannot be solved with interregional transmission lines and instead relate to other reliability constraints, then interregional transmission lines would lead to improved allocative efficiencies totaling \$2.23, rather than \$2.30, billion under 2022 conditions.

Moreover, the within-ISO constraints are largely coming from MISO rather than SPP (rows 5 and 6). This is in part simply due to the fact that MISO is larger, with more than double the hourly generation of SPP. However, it is also notable how much more within-MISO constraints have risen over time, relative to SPP; this is in part due to MISO's larger quantity of natural gas generation (nearly triple that of SPP's), combined with rising natural gas prices nationwide. I next turn to assessing model fit, and then to descriptive evidence of the sources of these spatial constraints.

D. Model Fit

This section assesses the extent to which the modeled outcomes match observable outcomes. Supplemental Appendix A2 gives further details, including tables and figures, on what is summarized here. I show that generation quantities and prices both match observable outcomes well. Mean modeled generation in the constrained counterfactual exactly matches real-world generation, by construction. More informative is that the standard deviation and various percentiles are also close. Moreover, the correlation between observed and modeled generation is high, whether measured at the hour-by-unit level or at the cross-sectional level. Thus, the model accurately predicts which units tend to get dispatched and which do not. The correlation is also very high for generation outcomes aggregated to the region by month by fuel and technology level, implying that the model does a good job of dispatching coal versus natural gas across space and time.

Observed and modeled prices also closely match. I collect hub-level locational marginal prices from both MISO and SPP (Midcontinent Independent System Operator 2016–2022c; Southwest Power Pool 2016–2022c), comparing these prices to the prices generated by my model. The average hourly price is very close (within 2 percent). This is remarkably close given that the model does not use actual price data in any way; rather, by making a few assumptions about marginal cost, spatial constraints, and market clearing, the model replicates the observed level of prices. Observed and modeled prices are also correlated, as expected, albeit at a lower level than are quantities. This is because steeply convex marginal cost curves push prices very high in some hours. Dropping outliers in both observed and modeled generation yields a much higher correlation. To ensure that the main results are not driven by these outliers, below, I conduct a robustness check that winsorizes hourly prices.

In addition to assessing the level of prices, I assess the geographic dispersion of prices. This is an important indicator, as it reflects the presence of spatial constraints. Geographic dispersion in observed prices tracks the time pattern of price dispersion generated by the model, as well as the time pattern of the allocative inefficiencies reported above. This provides reassurance that the allocative inefficiencies reported above are indeed indicative of geographic constraints that lead to price separation across space. Similarly, I show that hours with a high degree of price dispersion also have a high level of modeled allocative inefficiency and hours with a low level of price dispersion have lower allocative inefficiencies.

I next regress the price dispersion measure on demand, fuel prices, and wind potential, following equation (4) and Table 2. I show that all of these increase price dispersion, just as they increase modeled allocative inefficiencies. That is, allocative inefficiencies and geographic price dispersion depend in similar ways on market

observables. Finally, I collect data from each ISO on the number of binding constraints in their dispatch algorithm, and on the shadow value of these constraints (Midcontinent Independent System Operator 2016–2022d; Southwest Power Pool 2016–2022d). I show that allocative inefficiencies are closely related to these binding constraints, providing reassurance that the modeled results reflect spatial constraints rather than other market inefficiencies.

Overall, the observed and modeled data match well, providing reassurance that the model accurately represents real-world conditions and that the measured allocative inefficiencies are indicative of geographic constraints. I next assess the sources of these spatial constraints.

E. Sources of Spatial Constraints

Section IIIC shows that total generation costs can increase substantially if generation is regionally constrained. In 2022, across-ISO and within-ISO regional constraints (ignoring curtailment effects) together added \$1.64 billion in generation costs for fossil units. Of this, the single largest source is within-MISO constraints (\$1.09 billion). To better understand these constraints, I turn to evidence on observed generator dispatch.

I use the CEMS data on hourly generation for each fossil generating unit in MISO and SPP, and I run horse race regressions on the observed load in different regions. These regressions answer the question, Do generators respond more to nearby or distant load (demand)? If the electrical grid were physically unconstrained, generators would be expected to respond equally to a demand shock in any location. If we observe that generators are more often dispatched in response to a demand shock in their own region, that suggests that the electrical grid is constrained in some way.³⁴

For identification, I must assume that demand shocks are exogenous. This assumption is made in most papers on electricity economics that use hourly generation; the majority of consumers do not face real-time prices and so are not incentivized to respond to hourly shocks to supply.

I run a separate regression for each power plant, as follows:

$$(5) \quad g_{i,t} = \beta_1 d_{SPP,t} + \beta_2 d_{MISO,t} + \beta_3 d_{EI,t} + \mathbf{X}'_t \Theta + \varepsilon_{i,t},$$

where generation g at power plant i in hour t is a function of demand d in hour t in SPP, MISO, and the Eastern Interconnection. As noted above, the US electricity grid is divided into three interconnections, with very limited (nearly zero) flows across interconnections. MISO and SPP are both located in the Eastern Interconnection, so I control for demand in the rest of that interconnection (after subtracting MISO and SPP demand).

³⁴One could imagine instead regressing generation at each power plant on *prices* across regions; but this is not identified because of reverse causality. When plants are able to generate, prices will be lower, but what one wants to estimate is whether, when prices are higher, generators respond by increasing production. One could estimate this with some shifter of prices, for instance, hourly demand in each region. Essentially, I am estimating the reduced-form version of such a 2SLS specification.

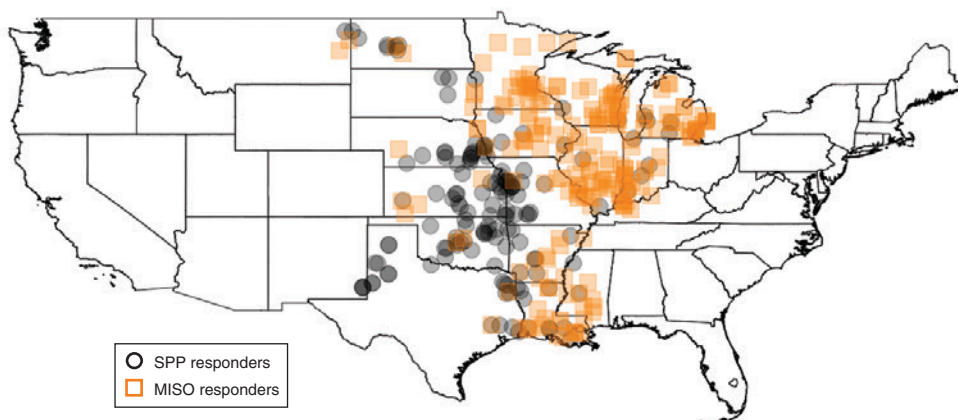


FIGURE 3. POWER PLANTS ARE DISPATCHED FOR OWN-ISO LOAD

Notes: This figure shows whether power plants are dispatched at higher levels of generation in response to SPP load (gray circles) or in response to MISO load (orange squares). The response generally matches the footprint of ISOs, with generators in states such as Nebraska responding to variation in SPP load and generators in states like Illinois responding to variation in MISO load. Horse race regressions are used to determine to which ISO's load the generator is dispatched, following equation (5) in the text.

With the assumption that demand is exogenous, additional control variables may not be needed to estimate equation (5). Nonetheless, I follow the literature in including controls \mathbf{X} for fuel prices (natural gas, coal, and oil), weather (ambient temperature), a time trend, month-of-year effects, day-of-week effects, and hour-of-day effects. These controls may be useful for accounting for things like maintenance outages, planned for specific months of the year, which are correlated with demand. Additionally, the controls may help with precision. In the Supplemental Appendix, I show results without controls.

I estimate equation (5) separately for each of the roughly 350 fossil plants in my CEMS sample,³⁵ with each regression using hourly data covering 2016–2022.³⁶ I then collect the estimated $\hat{\beta}$ coefficients, and I examine whether $\hat{\beta}_{SPP}$ or $\hat{\beta}_{MISO}$ is larger for each power plant. That is, is each power plant dispatched more in response to demand in its own ISO or in the neighboring ISO?

Figure 3 maps the location of each power plant, with separate markers to show whether the plant is dispatched at higher levels of generation more in response to SPP load (gray circles) or to MISO load (orange squares). The response closely matches the footprint of each ISO, with Western generators being dispatched in response to SPP load and Eastern generators in response to MISO load. The MISO

³⁵For statistical power, I collapse to the plant level rather than the generator level. Also, I drop a small number of plants that generate very infrequently. I keep only units with at least 336 nonzero generation hours, equivalent to two weeks over my seven-year sample.

³⁶The primary sample for equation (5) drops February 2021, when Winter Storm Uri disrupted energy markets in Oklahoma and Texas. During that period, natural gas prices spiked from around \$4/mmBtu to more than \$25/mmBtu (leading to outliers in my control variables), and some generators were forced to shut down because of weather. In the Supplemental Appendix, I show results that include this period.

service territory extends northwest into North Dakota and Montana; the SPP and MISO footprints are intermingled in those states.

The Supplemental Appendix shows that 91 percent of SPP plants have $\hat{\beta}_{SPP} > \hat{\beta}_{MISO}$, and 84 percent of MISO plants have $\hat{\beta}_{SPP} < \hat{\beta}_{MISO}$; the large majority of power plants are dispatched more in response to demand within their own region. The remaining 9–16 percent of power plants that respond to *other* ISO load tend to have results estimated with less precision. The Supplemental Appendix shows a map comparable to Figure 3 but where markers are sized according to the t -stat on the difference in the two coefficients. That map shows that power plants responding to the ISO outside their region tend to have smaller t -stats, reflecting either a smaller difference in the two point estimates or more noise in the estimation. The Supplemental Appendix also shows that the 84 to 91 percent numbers are similar for alternative horse race specifications and various weighting schemes.

I next extend the horse race regressions to examine the possibility of within-ISO constraints. Specifically, I break out demand into three regional variables—North, Central, and South—for each ISO. For power reasons, I do not include all six regional load variables in the horse race regression; rather, I include the three regional demand variables for a power plant's own ISO, plus total demand in the other ISO, and total demand in the rest of the Eastern Interconnection. For an SPP-located unit, for instance, the regression is

$$(6) \quad g_{i,t} = \beta_1 d_{NorthSPP,t} + \beta_2 d_{CentralSPP,t} + \beta_3 d_{SouthSPP,t} \\ + \beta_4 d_{MISO,t} + \beta_5 d_{EI,t} + \mathbf{X}'_t \Theta + \varepsilon_{i,t}.$$

Figure 4 displays whether each fossil power plant responds more to Northern (black X), Central (orange square), or Southern (gray circle) regional load within their own ISO. For SPP, the pattern is only weakly detectable. This is consistent with the results in Table 1, which showed that within-SPP constraints contribute little to allocative inefficiencies. In contrast, in the MISO region, power plants in the North (e.g., North Dakota) tend to be dispatched in response to Northern demand; plants in places like Illinois tend to be dispatched in response to Central demand, and plants in Louisiana in response to Southern demand. This is consistent with transmission constraints tending to bind *within* MISO, and it can explain why the within-MISO allocative inefficiencies are large in Table 1.

Finally, I conduct similar horse race regressions with prices as the outcome variable. Results are shown in the Supplemental Appendix. Hourly hub-level prices tend to respond more to own-ISO demand shocks and also more to nearby regional demand shocks within their ISO.

The horse race regressions are useful for several reasons. First, they are a new way of demonstrating the role of grid constraints across space. In doing so, they provide empirical support for the argument that eliminating spatial constraints could improve grid outcomes by allowing power plants to respond to demand in different regions. Second, they confirm what Table 1 shows: Within-ISO constraints matter, not only across-ISO constraints, and this is particularly true within MISO. Finally, it is reassuring that the stories told by Figures 3 and 4 closely match the overall story of Table 1 because the methodologies I use in each one are so different. The maps

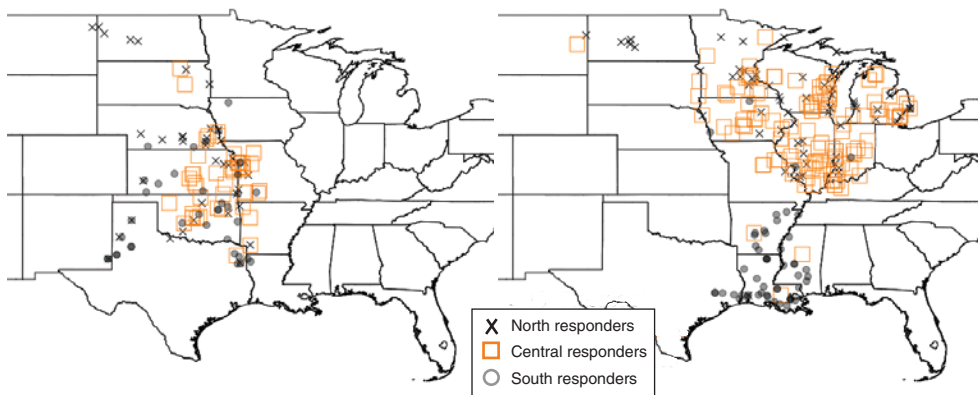


FIGURE 4. SOME POWER PLANTS ARE DISPATCHED MORE FOR OWN-REGION LOAD

Notes: This figure shows whether power plants are dispatched at higher levels of generation in response to Northern (black X), Central (orange square), or Southern (gray circle) regional load within their own ISO. Within SPP (left panel), no clear pattern is detectable. In contrast, MISO generators (right panel) appear to respond more to nearby load than to faraway load.

come from hourly horse race regressions that are agnostic about the regional location of individual power plants and instead leverage hourly variation in demand across space. The allocative inefficiencies results in Table 1, in contrast, come from a constructed market equilibrium based on marginal costs and on NERC-by-ISO-defined geographic regions. Yet the two methods tell the same story about the importance and rough location of geographic constraints across and within ISOs.

F. Market Power

I conclude these empirical results on allocative inefficiencies by discussing the role of market power. As Cicala (2022) notes, market power can be exercised by the withholding of generation from a unit, and this has been a focus of a strand of the electricity literature. In this section, I consider whether market power could produce the empirical results I observe. Both market power and transmission constraints can change how much electricity is generated in a region, so disentangling the two is important.

Suppose a generator withholds production to raise prices for other units owned by the same firm. If this occurs uniformly across all regions, it will not lead to the wedges I report. With inelastic demand, aggregate *regional* quantities would be unaffected, and my counterfactuals assume competitive bidding within each region.³⁷

³⁷Note that a similar argument would apply if one were concerned that my results are an artifact of uneconomic dispatch by some units, as some analysts have alleged. Specifically, the claim has been made that some power plants, particularly investor-owned coal units, generate even when their marginal cost is above the price they receive and that this reflects more than simply ramping or other dynamic constraints. I do not take a stand on whether this is true. But it will impact my results only if it is geographically concentrated, such that the regional quantity constraints I impose are affected. But crucially, the claims made in the existing literature apply across the MISO and SPP footprints (Daniel 2017; Fisher et al. 2019; Daniel et al. 2020; Zimmerman et al. 2024).

Next, consider a case where withholding occurs in some regions more than others. This is plausible if there are differences across regions in the marginal cost profile of generating units. Withholding would then lead to generation being less than a competitive counterfactual across an entire region, and my counterfactual would incorrectly model this as a transmission constraint.

It is implausible, however, that market power alone creates the allocative inefficiency I observe. First, there is geographic dispersion in observed market prices, as described in Section IIID. This would not occur if there were market power being exercised in a geographically integrated market. Second, we observe generators responding to own-region demand more than other-region demand, as shown in Section IIIE. This will not occur with simple withholding in a geographically integrated market: The coefficients on own-region demand and other-region demand would still be expected to be equal. Instead, both observed prices and observed generation outcomes imply geographically distinct markets.

Third, it is usually argued that the US electricity market is too large for market power to be sustained except where transmission constraints bind. As Wolak (2014) notes,

There are a large number of electricity suppliers in the United States, none of which controls a significant fraction of the total installed capacity in the United States. Consequently, the market power that an electricity supplier possesses fundamentally depends on the size of the geographic market it competes in, which depends on the characteristics of the transmission network and location of final demand. (p. 217)

That is, market power *enabled* by transmission constraints is plausible, but market power *instead* of transmission constraints is not. I return to this point below.

Fourth, both MISO and SPP are required to have a market monitor that screens for market power of various forms, and both ISOs have multiple market power mitigation procedures (Graf et al. 2021; Potomac Economics 2023; Southwest Power Pool Market Monitoring Unit 2023; Federal Energy Regulatory Commission 2024). The market monitor knows the marginal cost of each plant and has multiple tests for deviations from marginal cost bidding (including evaluating plant outages, price markups, output gaps, and whether individual suppliers are pivotal). Over my sample period, both market monitors have detailed annual reports with descriptions of how they screen for anticompetitive behavior, and both find that firms have behaved competitively in the vast majority of hours.³⁸

Transmission constraints do make the exercise of market power more likely (Wolak 2014; Graf et al. 2021; Potomac Economics 2023; Southwest Power Pool Market Monitoring Unit 2023; Federal Energy Regulatory Commission 2024), so both market monitors specifically screen for this using multiple criteria. A load pocket can allow a local generating company to behave anticompetitively within that pocket, as competitors cannot physically supply to the area. This would indeed lead to observed regional generation quantities being smaller in the load pocket than what a competitive market would suggest; my model would pick this up as a transmission

³⁸Potomac Economics (2017, 2018, 2019, 2020, 2021, 2022, 2023) and Southwest Power Pool Market Monitoring Unit (2017, 2018, 2019, 2020, 2021, 2022, 2023).

constraint. In that case, however, I would be *understating* the cost of the transmission constraint. The model assumes that units are dispatched according to least cost within a region and therefore does not pick up withholding or other monopolistic bidding within the region. Future research could look for evidence of local exercise of market power enabled by transmission congestion, but again, recall that market monitors and operators actively try to prevent this in MISO, SPP, and other regions.

IV. Political Economy Implications: Some Producers Gain and Some Lose

I have thus far shown that power plant dispatch in the Midwest is more costly than it would be in a world without curtailments and without spatial constraints. This is in line with evidence from other regions, including Texas and Chile (LaRiviere and Lyu 2022; Gonzales, Ito, and Reguant 2023). I have also shown that the magnitude of the resulting inefficiency has grown over time, becoming more policy-relevant with increasing curtailments and increasing fuel prices. I next turn to an analysis of how eliminating curtailments and spatial constraints might affect individual power plants and their owners. In particular, I calculate net revenues for each power plant under a least-cost dispatch scenario versus a regionally constrained and wind-curtailed scenario.

The literature on transmission constraints and renewables integration has focused on total allocative inefficiencies. It has largely ignored the role of producer surplus at individual plants or individual firms. Yet understanding the impacts of better grid integration on individual firms also matters for policy analysis. Transmission planning is largely a consensus-based process, with opportunities for actors to hold up new transmission development throughout the transmission planning process (Davis, Hausman, and Rose 2023). For political economy reasons, then, it is important to understand the incentives of firms to push for or to block new transmission lines and other market integration reforms.

The counterfactuals in Sections IIIA and IIIB yield predicted quantities generated at each power plant. I can also use those counterfactuals to calculate equilibrium prices, equal to the marginal cost of the marginal generating unit. It is a market-wide price in the counterfactual without spatial constraints, and it is a vector of region-specific prices in the regionally constrained equilibrium. I then calculate net revenues as the revenues minus fuel and other variable costs; this static analysis ignores fixed costs (equivalently, I assume that fixed costs are equal across my two counterfactuals). For each generating unit, I calculate net revenues in each of my sample hours. I then aggregate across generating units to the power plant level.

Before presenting results, I discuss how this net revenue variable relates to overall profits. The relationship between the two depends on whether the utility is an investor-owned utility facing rate of return regulation, or a merchant generator. Nationwide, capacity is roughly split between the two types. For merchant generators, net revenues have a direct impacts on profits. However, for vertically integrated investor-owned utilities, which make up the majority of my MISO and SPP sample, the relationship is more indirect. It will depend on the complex negotiations between utilities and the state-level commissions that regulate them, as in, for instance, Lim and Yurukoglu (2018) and Gowrisankaran, Langer, and Reguant (2024). These negotiations are over how prices are set and what profits are allowed.

There are three mechanisms through which my net revenues will be correlated with the profits of an investor-owned utility. First, the utility may be the residual claimant on some of the revenues earned from wholesale sales in excess of its retail-serving needs. Second, high prices and load pocket conditions can justify investments in new power plants, on which the utility can earn a rate of return. And finally, power plant run times can be correlated with the utility's ability to keep past investments "used and useful" (Gowrisankaran, Langer, and Reguant 2024). When assets like power plants are not "used and useful," regulatory commissions may reduce the allowed returns for investors. Thus, even when the utility is not the residual claimant on excess net revenues in the short term, it can benefit from being in a load pocket by being able to justify new investments and delayed retirements.

A. *Incentives to Block Integration Increase as Renewables Enter*

As shown in Section IIIC, the allocative inefficiencies from inadequate market integration have been rising over time, in part as a function of increasing curtailments of renewables. Relatedly, the incentives for incumbents to block new transmission lines or other market integration reforms are also increasing as new renewables enter. Integrating the market implies that those low-cost renewables can be exported to other regions, which can both displace fossil generation and also lower market prices for the remaining fossil generation.

To understand the effect of renewables on existing fossil generators, I focus on MISO South, a region with no wind generation. I regress net revenues at the hourly level (for all of MISO South generators aggregated) on potential wind generation across the MISO and SPP footprints. Potential wind generation is the sum of wind generation that made it to market and wind generation that was curtailed; recall that it is therefore exogenous to market activity. I estimate three regressions, each with a different dependent variable: (i) net revenues in the regionally constrained counterfactual, (ii) net revenues in the integrated market counterfactual, and (iii) the change in net revenues a firm experiences when the market moves from constrained to integrated.

This regression has a causal interpretation provided that total wind potential is a function of exogenous weather patterns and that weather does not impact dispatch and net revenues except via its impact on wind (conditional on controls, noted below). There are two things to note about this. First, the regression takes wind generation as given, and so it ignores the *dynamic* effects of market integration on wind capacity. I comment more on this below.

Second, because the regression is causal only if wind generation is uncorrelated with the error term, I must control for other impacts of weather on the grid, most obviously demand. I also control for other determinants of generator dispatch and prices: fuel prices and various time effects (month of year, day of week, hour of day). Table 3 shows the results.

Column 1 shows that as wind enters the market, net revenues at conventional generators in MISO South drop; for every 1 GWh of additional wind, net revenues at all fossil and nuclear plants combined drop by \$1,300. To put this number in perspective, as hourly wind (both generation and curtailments) increased from 10.9 GWh in 2016 to 25.9 GWh in 2022, the coefficient would imply that hourly net revenues in

TABLE 3—INCENTIVES FOR CONVENTIONAL GENERATORS IN MISO SOUTH TO BLOCK MARKET INTEGRATION INCREASE AS RENEWABLES ENTER

	Net revenues, regionally constrained (1)	Net revenues, integrated market (2)	Change in net revenues from integration (3)
Potential wind generation, GWh	−1,330 (241)	−4,415 (283)	−3,085 (284)
Observations	61,276	61,276	61,276
R^2	0.53	0.80	0.18

Notes: The unit of observation is an hour. The independent variable is the total amount of potential wind generation across MISO and SPP, summing across actual wind generation and curtailed wind generation, in GWh. The dependent variable is net revenues, measured in dollars in an hour, aggregated across all conventional and nuclear plants in MISO South, a region without wind generation. Standard errors are clustered by sample week.

this region dropped by around 10 percent. However, had the market been integrated, that same increase in wind would have implied a drop in hourly net revenues of \$4,400 (column 2). As wind has entered SPP and MISO North/Central, the losses from integration for MISO South generators have substantially increased.

Recall that column 3 of Table 3 understates the incentives for conventional generators to block transmission because it does not capture the effect of new transmission on wind investment in the medium to long run. That is, Table 3 takes potential wind generation as exogenous, but new transmission can incentivize new renewables development, as shown by Gonzales, Ito, and Reguant (2023).

Of course, net revenues increase at wind generators as they are able to enter the marketplace and as they are able to export to nonwindy regions (see Supplemental Appendix). The political economy and regulatory questions, then, relate to whether new entrants have an equal voice in the negotiation process for new transmission lines, an issue I return to below.

B. *Winners and Losers Are Located in Different Regions*

Figure 5 displays the location of each fossil, nuclear, and wind power plant in SPP and MISO, along with how net revenues compare under my two counterfactuals. Specifically, I calculate whether net revenues would rise or fall if spatial constraints and curtailments were eliminated. The plants that would lose the most (at least \$10 million in 2022) from eliminating spatial constraints and curtailments are shown in large red circles (a drop in net revenues of at least \$20 million) or orange circles (a drop between \$10 and \$20 million); the plants that would gain the most are shown with large green squares. Plants that are less affected are shown with smaller markers.

Consistent with Table 1 and Figures 3 and 4, there is a pronounced regional pattern. Plants in Northern and Central MISO and Southwestern SPP would gain the most, and plants in Southern MISO would lose the most. These patterns make sense given observed congestion in MISO and SPP; for instance, the Supplemental Appendix shows a map of real-world annual average prices in 2022, with below-average prices

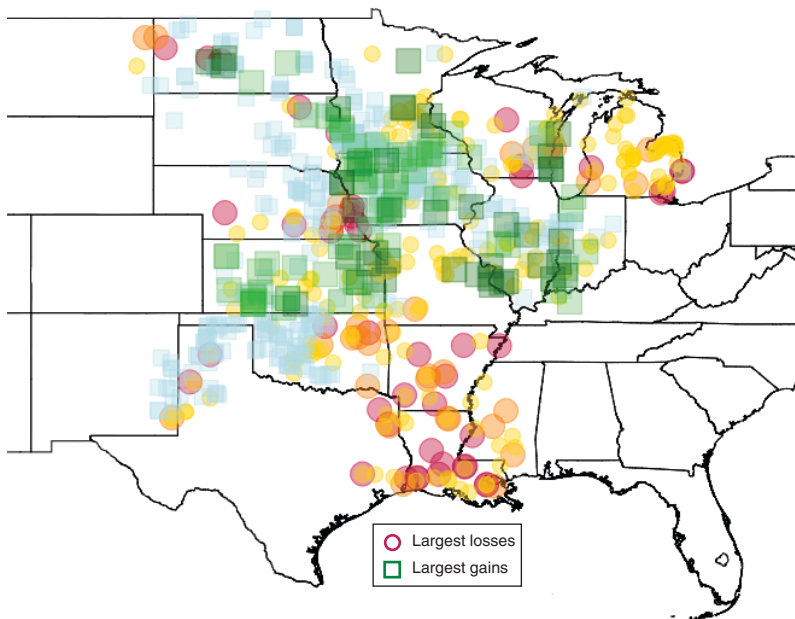


FIGURE 5. POWER PLANTS THAT GAIN VERSUS LOSE ARE LOCATED IN DIFFERENT REGIONS

Notes: This figure shows whether individual power plants would win or lose if spatial constraints across regions were eliminated and wind fully dispatched rather than curtailed. Plants losing more than \$10 million per year, based on 2022 counterfactuals, are displayed in large red circles (a drop in net revenues of at least \$20 million) or orange circles (a drop between \$10 and \$20 million). Plants with a drop in net revenues of less than \$10 million are in small gold circles. Plants with net revenue gains of at least \$10 million are in large dark green squares (gains greater than \$20 million) or light green squares (gains between \$10 and \$20 million), and plants with smaller net revenue gains are in small blue squares.

in places like Nebraska, Kansas, southwest Minnesota, and northwest Iowa, and with above-average prices in Michigan and MISO South.³⁹

This regional pattern has political economy implications. Generation firms operating in Southern MISO are not incentivized to develop new transmission lines that better integrate their power plants with the rest of the SPP and MISO footprints. In fact, these firms are likely to have financial incentives to block new lines, an incentive that has grown as wind has entered SPP and the rest of MISO.⁴⁰

The magnitude of the political economy problem is striking. The four firms that stand to lose the most would have experienced a combined drop in net revenues of \$1.3 billion in 2022 alone, had the market been fully integrated and wind not curtailed. This is equal to more than half of the total allocative inefficiencies for 2022. In other years, the net revenue drop for the four most affected firms would have been smaller in *level* terms, but it would still have been roughly comparable

³⁹The broad geographic patterns in Figure 5 and the prices map in the Supplemental Appendix are similar. Some differences are that my measure of spatial constraints is less geographically fine-grained (thus ignoring, e.g., congestion between Western and Eastern Kansas) and that my model does not capture some of the high prices that were seen in parts of RFCW in 2022.

⁴⁰Note that reforms for market integration centered on institutional rules, rather than physical infrastructure, would face the same incentive problems.

in relation to the allocative inefficiencies in each year.⁴¹ Indeed, a time series in the Supplemental Appendix shows that the magnitude of losses at these four firms is strongly correlated (over time) with allocative inefficiencies: As the potential gains to society have grown, so have the potential losses to these firms.

I also calculate which firms would win from better market integration; I find that they are primarily located in states like Iowa, Kansas, Minnesota, and Missouri.⁴² Here, the 4 firms that stand to gain the most collectively would have seen net revenues of around \$1.6 billion more in 2022.

Wind generators as a group would have earned around \$1.7 billion more in 2022 with market integration. In Figure 5, they mostly appear as light blue squares: They individually gain, but the dollar values at any one site are relatively small simply because each plant has small capacity. Unfortunately, I do not observe full ownership data for the wind producers, so I cannot say precisely how large the gains would be at individual firms. The \$1.7 billion that I estimate they would gain is spread out across hundreds of wind sites. Taking the EIA ownership data at face value (thus ignoring the possibility of subsidiaries), there are more than 300 utilities with wind generation in my sample, and thus, the magnitude of gains to individual firms is small.⁴³

Unfortunately, my ownership data do not track parent firms of subsidiaries, a problem that is particularly acute for wind producers. Consider the case of NextEra, one of the largest wind owners in the country. Comparing the generation and capacity totals that NextEra reports on their website to national wind totals, we see that NextEra owns nearly 15 percent of all US wind. According to their map, a large fraction of their footprint is in MISO and SPP.⁴⁴ In my data, however, their name only appears for around 1 percent of wind plants; the rest of their wind holdings are in LLCs, such as “Brady Wind, LLC.” I do not have a comprehensive listing tying the many wind LLCs in MISO and SPP to their ultimate parent firm. (In my data, 69 percent of wind owners have a name that includes the suffix “LLC,” whereas the comparable statistic for fossil owners is 17 percent.) Below, I discuss the political economy implications of wind’s potential gains from new transmission in light of these ownership patterns.

⁴¹ While I have primarily focused on fossil power plants, these calculations also include net revenue changes at these firms’ nuclear plants. Nuclear plants are assumed to be baseload in my model, so relieving spatial constraints and removing curtailments does not change their quantity generated (and therefore, the behavior of nuclear plants is not a source of allocative inefficiencies). It does, however, change the revenue received at these plants. Some of the four most affected firms have sizable nuclear capacity, although it is smaller than their fossil capacity.

⁴² Again, I include nonfossil generation, and some of these firms have nuclear and/or wind capacity. Unfortunately, I do not observe wind generation disaggregated to individual locations; nor do I observe wind curtailments disaggregated across space. I allocate hourly regional (that is, SPP plus three broad regions within MISO) wind generation to individual firms based on annual totals reported in EIA-923, and I allocate curtailments based off ISO-level totals, the finest level of disaggregation I have. As discussed below, there are limitations in the wind ownership data, as I do not observe parent firms. The calculations here ignore the possibility of subsidiaries and take at face value the ownership reported in EIA data.

⁴³ Note that the four firms for which I report the greatest drops in net revenue have very little wind capacity. The top two firms have no wind capacity according to EIA data and according to their website. The other two also primarily own conventional generators, although they each have some wind capacity.

⁴⁴ NextEra generation and capacity for 2020 are taken from https://www.investor.nexteraenergy.com/~media/Files/N/NEE-IR/Sustainability/2022%20By%20the%20Numbers/2022_By_the_Numbers_vF.xlsx (accessed July 1, 2025). National generation is taken from <https://www.eia.gov/electricity/data/browser>, and capacity from <https://windexchange.energy.gov/maps-data/321>, each accessed December 12, 2023.

Electricity consumers also matter. These consumers range from individual households to commercial and industrial establishments. I do not present consumer surplus estimates since I do not know the physical location of different consumers (which would be needed to calculate the equilibrium price they face in different scenarios). I also do not model how wholesale prices are passed through to retail rates. However, in general, one would expect consumers in load pockets to gain as their prices fall with market integration.

One caveat to bear in mind when analyzing Figure 5 and the statistics in this section is that the counterfactual net revenues at individual power plants depend on the specifics of the dispatch model used as well as the grid conditions (e.g., demand levels and fuel prices). Therefore, in Section V, I conduct a variety of robustness checks. The specific dollar amounts vary across alternative counterfactual construction methods and across years. But the main takeaways for political economy purposes—the order of magnitude of net revenues changes in comparison to total allocative inefficiencies, and the broad geographic patterns—are quite stable.

C. Case Study: MISO South

That the two generating firms that would lose the most from grid integration in 2022 are in MISO South is unsurprising; this area has long been known as a pocket with inadequate transmission ties to the rest of MISO. These two MISO South firms are Entergy Arkansas and Entergy Louisiana, both subsidiaries of Entergy, with my model showing integration leading to a combined \$850 million drop in net revenues in 2022. The history of the interactions between Entergy and MISO regarding transmission planning are illuminating. Entergy has a market value of over \$20 billion and has generation, transmission, distribution, and retailing divisions across much of MISO South (including Arkansas, Louisiana, Mississippi, and Texas).⁴⁵ For more than a decade, it has faced allegations of using both its own transmission system and the transmission planning process in MISO to prevent competition for its generation business.

Indeed, Entergy joined MISO in 2012 following a Department of Justice investigation into

allegations that Entergy has engaged in exclusionary conduct in its four-state utility service area ... Specifically, the division has been exploring whether Entergy has harmed consumers by exercising its control over its transmission system and dominant fleet of gas-fired power plants to exclude rival operators of low-cost combined-cycle gas turbine (CCGT) power plants from competing to sell long-term power. (Department of Justice 2012)

Entergy joined MISO but has since been accused of stalling the MISO transmission process, again to protect its fossil plants.

More recently, watchdog groups and green advocates have argued that Entergy disrupts the transmission planning process (Tomich 2021), as one might predict in

⁴⁵Market value is as of March 2023; source is https://cdn.entergy.com/userfiles/content/about_entergy/pdfs/Entergy-fact-sheet.pdf, accessed December 18, 2023.

a planning process in which incumbent generators have a seat at the table (Davis, Hausman, and Rose 2023). One group claimed that “Entergy secretly placed a consultant to advance its interests in MISO stakeholder meetings under the guise of a ‘MISO South customer’”; the watchdog group argues that this may have been part of an attempt to prevent competition from wind generation (Tait 2020). Finally, twice Entergy has built new fossil plants, in part justifying the investment costs by pointing to transmission constraints, and then subsequently argued that new transmission lines were no longer needed (Kovvali and Macey 2023; Howland 2023). While Entergy as an investor-owned utility may not be the residual claimant on all net revenues from the wholesale market, these actions are consistent with a desire to protect its rate base.⁴⁶

A caveat is that some of the most vocal opponents of Entergy have been renewable energy stakeholders, who could be biased; they stand to gain the most from grid integration. One might decide to take the accusations against Entergy with a grain of salt given the incentives of renewable energy stakeholders. But the incentives of renewable developers may match what would be optimal for society, given a lack of nationwide carbon pricing.

A related question is how the potential winners from grid integration behave in the transmission planning process and whether they are incentivized to and capable of pushing for the build-out of new interregional lines. Recall that the primary winners are (i) existing wind generators that would be curtailed less and would see higher wholesale prices, (ii) new wind entrants, and (iii) the consumers in load pockets who would see lower prices. The anecdotes above suggest that renewable generators are collectively pushing for new transmission projects. However, renewables firms and consumer advocates face two potential barriers: First, legal analysts have argued that the transmission planning process favors incumbent producers and disadvantages ratepayers, and it is possible that potential losers are more effective at lobbying than potential winners.⁴⁷ Klass et al. (2022) argue that regional transmission organizations (RTOs) favor incumbent interests in a variety of ways: a result of the fact that membership is voluntary, so incumbents can threaten exit, and the fact that large utilities tend to have the most voting authority (rather than state governments, consumer advocates, or other interested parties). In the conclusion, I briefly discuss potential reforms.

Overall, I argue that understanding the political economy of new transmission lines is just as important as understanding the potential gains in allocative efficiency. There are many tactics an incumbent firm might use to protect its generation assets, as the MISO South case studies show, and the financial incentives to do so can be tremendous. These incentives depend on the mix of generation, transmission, distribution, and retailing that a firm owns and operates; a utility that is a net purchaser of generation and primarily engages in distribution and retailing

⁴⁶The rate base refers to the firm’s investments, on which it is allowed a rate of return profit.

⁴⁷For instance, Meng and Rode (2019, p. 473) find “that firms that are expected to lose [from cap-and-trade] are more effective at lobbying to lower the policy’s chances than firms that are expected to gain are at lobbying to raise the policy’s chances.” And Colgan, Green, and Hale (2021, p. 594) argue that “policymakers are loath to harm important economic assets even if asset holders do not proactively defend them.” It is plausible that this policymaker preference would be asymmetric in the sense that it would not show up as an equal desire to protect, e.g., new entrants.

may have an incentive to seek out low-cost generation. It also depends on whether the utility is price regulated, and if so, what relationship it has with a utilities commission. I am aware of no reports like those regarding Entergy that have emerged for other utilities in my sample whose generation assets would be worth less under a more integrated grid. Nonetheless, the results in this section suggest that the current planning process is problematic given the fact that market integration would bring very large losses to some incumbents.

V. Robustness Checks

In this section I evaluate whether the results above are similar under alternative assumptions about market equilibria. I allow for changes in the definition of regional constraints, the sample composition, the capacity of the generating units, the marginal cost of the generating units, the inclusion of engineering constraints, the inclusion of line losses, and the definition of the equilibrium price. I also look at what might happen in a future with more wind capacity. For each robustness check, I reconstruct the market equilibria in every hour. In this section, I show that the reported annual allocative inefficiencies are comparable across all the robustness checks. I also show that across these robustness checks, gains and losses at individual firms are large.

A. *Alternative Assumptions Used for Robustness Checks*

I begin by describing why each robustness check is useful. First, and most importantly, I construct two alternative definitions of regional constraints. My primary specification uses NERC subregions interacted with ISOs (map in Supplemental Appendix). In the first robustness check, I use a much more conservative definition. I construct simply three regions: SPP, MISO North/Central, and MISO South. I use these three because they are readily apparent in the horse race regressions above as sources of congestion. This robustness check thus serves as a useful lower bound: It does not include constraints within SPP or between North and Central MISO, for instance. This means a more conservative assumption on the scope of subregional constraints.

I also allow for smaller regions to define the spatial constraints: Rather than using NERC subregions, I use zones from the National Renewable Energy Laboratory's ReEDS model (Cole et al. 2021) (again interacting them with the MISO versus SPP indicator). There are typically one to six zones per state in the ReEDS model (map in Supplemental Appendix). The advantage of using these zones is that it allows me to pick up more localized transmission constraints than when I use NERC subregions. The disadvantage is that I may falsely attribute to transmission constraints *other* deviations from least-cost dispatch observed in the real world (e.g., an unexpected plant outage) that impact the overall generation in a ReEDS zone. In contrast, when regional definitions are broad, these deviations across space are more likely to be averaged out across plants, thus not impacting overall generation in the region.

Second, I change the sample composition by allowing units like combined heat and power units and industrial generators to participate in the market. In the main

results, I follow the literature in assuming that the behavior of these units is driven by other considerations (for instance, the need to have steam for industrial processing), not by marginal revenue from the wholesale electricity market. I thus drop them from the sample. However, in this robustness check, I include these units, constructing marginal cost curves as a function of heat rates, fuel prices, and operations and maintenance (O&M) costs (just as I do for the main sample) and including these units in my least-cost dispatch algorithm.

Third, I change the capacity and marginal cost of each generating unit by assuming that the unit's capacity is equal to its sample-wide maximum observed generation rather than its yearly maximum observed generation. I similarly set the heat rate of each unit to be equal to its sample-wide heat rate rather than its annual heat rate. This robustness check has the disadvantage of assuming that a unit with a capacity expansion partway through the sample was able to generate at that higher level throughout my sample. It has the advantage of capturing a higher capacity for units that operate infrequently and may not have reached maximum capacity in any given year. My fourth robustness check also modifies maximum capacity: I uniformly partially derate capacity across all units rather than stochastically applying unplanned outages.

Fifth, I modify marginal costs in several ways. In my main sample, I use annual state-level markups to construct generator fuel costs. In an alternative version, I use a time-invariant national markup. Next, I assume alternative variable operations and maintenance costs for combustion turbine generators; engineering sources disagree on the magnitude of these costs. In my primary specification, I assume variable O&M of around \$5.4 for combustion turbines, following Energy Information Administration (2022, 2023c). In two robustness checks, I instead use either \$0 or \$11.

Next, I construct robustness checks that incorporate additional engineering constraints not included in the primary least-cost dispatch model. In the first, I assume that there are unobservable constraints related to system-wide reliability and that combustion turbines are dispatched to satisfy these constraints. Accordingly, I force the region-wide generation for combustion turbines as a whole to be equal to what I observe in the real world; similarly, I force the region-wide generation for non-CTs (boilers and combined cycle units) to be equal to what I observe in the real world. That is, I allow least-cost dispatch *within* these technology groups. I include this constraint in both the integrated and regionally constrained counterfactuals.

Alternatively, I assume that units operating below their minimum constraint in the real world were following some set of unobservable incentives or constraints, and I force their generation in both of my counterfactuals to be equal to what these units generated in the real world. This provides reassurance that ramping or other dynamic constraints do not drive the results.⁴⁸

Next, I incorporate transmission line losses. According to the Energy Information Administration, around 5 percent of electricity is lost in transmission and distribution

⁴⁸ Another source of reassurance that dynamic constraints do not drive the results is that the allocative inefficiencies appear across all hours of the day (see Supplemental Appendix). In contrast, generating even when it is statically uneconomic to do so is most likely at night, with generators staying on to avoid start-up or ramping costs when electricity demand increases the following morning.

(Pacific Northwest National Laboratory 2024).⁴⁹ I have not modeled these losses in my main analysis, as I do not have a representation of the physical grid. A key reason for improving the transmission grid is to reduce line losses (Southwest Power Pool 2021; Department of Energy 2023b); in that sense, transmission losses should be viewed the same as any other source of geographic constraint on the grid, and my model is an approximation of what would happen if they were eliminated. However, to the extent that eliminating line losses is not feasible or not cost-effective, then my measured allocative efficiencies would be too large. To see this, I model a robustness check in which all quantity supplied after regionally aggregated observed quantities are satisfied faces a 5 percent penalty on both marginal cost and on capacity, representing line losses.⁵⁰

My next robustness check endogenizes congestion and curtailments. Rather than taking regional quantity constraints and curtailment quantities as given, I predict these variables as a function of hourly regional demand shocks, of regional wind capacity, and of wind speeds.

I next construct equilibria prices in two alternative ways. In my main specification, I assume that the equilibrium price is equal to the marginal cost of the marginal generating unit.⁵¹ However, some high-cost units may be dispatched because of reliability concerns or engineering constraints; as such, they might not be compensated at their marginal cost but rather receive payments in the ancillary services markets or various forms of out-of-market payments. Thus, in these two robustness checks, I instead set the equilibrium price at the marginal cost of the ninety-fifth or ninety-ninth percentile of dispatched fossil units. I also add a robustness check in which I winsorize prices sample-wide at the first and ninety-ninth percentiles.

Finally, I construct counterfactuals in which market separation persists in most places but where two adjacent regions are integrated. Some recent studies calling for expanded transmission have looked at large-scale integration across the United States; other studies have looked at build-out of just some key corridors (Brown and Botterud 2021; Bloom et al. 2021; Department of Energy 2023b; Goggin and Zimmerman 2023b; Department of Energy 2024). I conduct this analysis under two different sets of assumptions: assuming this integration solves the curtailments problem in both regions or assuming it has no impact on curtailments relative to the original constrained equilibrium. A table and map showing the various regional pairs is in the Supplemental Appendix.

⁴⁹This 5 percent statistic overstates the amount lost in transmission; the bulk of this 5 percent likely occurs in the distribution system (Pacific Northwest National Laboratory 2024). In MISO and SPP, the loss component of marginal prices is fairly small. Both ISOs report the component of locational marginal price dispersion that arises from congestion versus losses. Both components are approximately mean zero, by construction; to see the relative importance of each, instead consider the standard deviation or the mean absolute deviation. By both of these measures, congestion is much more important than losses for MISO and SPP prices over my study's time frame.

⁵⁰This robustness check ignores some nuances of line losses: In particular, they are larger when electricity is transmitted over long distances. Nonetheless, it can illuminate the extent to which line losses might be qualitatively important for my overall conclusions.

⁵¹Mills et al. (2021) provide empirical validation for this modeling of equilibrium prices across multiple years and multiple markets in the United States, including MISO and SPP. I also show comparisons between modeled and observed prices in the Supplemental Appendix.

B. Results for Robustness Checks

The annual allocative inefficiencies are similar under the alternative assumptions about market equilibria. In my main results, the allocative inefficiencies in 2022 add up to \$2.3 billion. In the robustness checks, the smallest value I calculate for allocative inefficiencies is in the scenario with only 3 broad regions defining the spatial constraints: \$1.4 billion. Recalling that this is a lower bound, it is striking that those 3 regional constraints alone contribute more than 60 percent of the inefficiency. The largest value I calculate for allocative inefficiencies is in the scenario with spatial constraints defined at the ReEDS-zone level: \$3.8 billion. Recall that this scenario uses smaller regions, so it attributes more of the real-world deviations from least-cost dispatch to spatial constraints, which increases the estimated value of allocative inefficiencies.

Across the remaining robustness checks, I calculate allocative inefficiencies in 2022 ranging from \$2.1 to \$2.5 billion, very similar to the main results. That is, the main results are not particularly sensitive to a variety of alternative assumptions about the sample composition, marginal costs, the nature of outages, the behavior of combustion turbines, the behavior of units at or below their minimum constraint, line losses, or even predicting regionally aggregated quantities using a vector of demand and wind variables.

Here, I briefly summarize the results for integration of adjacent regions rather than the entire market (the Supplemental Appendix provides details). The largest gains from integration across two adjacent regions come from connecting MISO-SRMV to SPP-SPNO—that is, roughly Arkansas/Louisiana to Kansas/Missouri. That yields gains of around \$560 million under 2022 conditions, or roughly one-quarter of the total reported in Table 1. Of the top gains from five pairwise combinations, three involve connecting MISO South to nearby parts of SPP. Thus, the overall messages of the paper are corroborated with this analysis: Cost savings from integration have been large in recent years, and MISO South is particularly isolated.

Above, I report that there are multiple firms that stand to lose substantial net revenues from integration, particularly in comparison to the allocative inefficiencies that the literature tends to focus on. In my main model, the 4 firms with the most to lose from integration would collectively have seen net revenues lowered by \$1.3 billion in 2022. Across robustness checks, this varies from \$1.0 billion to \$2.5 billion. The specific firm identities of the four with the most to lose vary somewhat across robustness checks, but the geographic patterns are similar.

Consider a state-level aggregation of firms: Across the more than 2,000 state by year by robustness check combinations, nearly 90 percent have the same sign (i.e., wins versus losses) as in the main results.⁵² And results for Entergy Arkansas and Entergy Louisiana are also similar in robustness checks. In Section IV, I report that these two would have collectively seen net revenues lowered by \$850 million in 2022 under market integration. Across the robustness checks, their combined net revenue changes for 2022 are similar: ranging from \$740 million to \$1.1 billion. In the pairwise integration with the largest allocative efficiency gains, Entergy

⁵²Moreover, in all states, the majority of robustness checks yield the same sign as in the main model. And in all robustness checks, the majority of states maintain the same sign as in the main model.

Arkansas and Entergy Louisiana again have the greatest revenue losses: \$300 to \$400 million, depending on what one assumes about curtailments, or roughly 40–50 percent of the losses for the full integration counterfactual.

Another way to evaluate the robustness of the claim that effects on firms are as important as total allocative inefficiencies is to count the number of firms that experience a drop in net revenues equal to at least 10 percent of the society-wide gains from removing spatial constraints. In all robustness checks across all years of my sample (119 different counterfactual comparisons), the median number of such firms is 5.

I also examine who would win and who would lose if wind generation were higher than it is today. Without a dynamic entry model, I cannot predict *where* new wind would enter. Instead, I assume that wind expands capacity in the same places as existing capacity, and I examine how this changes the patterns and magnitudes of wins and losses for incumbents. When wind capacity increases (by either 10 percent or 100 percent, allocated to the same locations as existing capacity), the results for winners and losers are similar; Entergy Arkansas and Entergy Louisiana remain among the largest losers from market integration, and the magnitude of their drop in net revenues increases.

My main model follows the literature in terms of assumptions about marginal cost, capacity, and equilibrium prices. When I use alternative assumptions, I find similar results for total allocative inefficiencies and firm-level gains and losses. Thus, it does not appear that any of these results are an artifact of my assumptions about the MISO and SPP markets.

VI. Conclusion

This paper leverages rich data across a broad part of the United States to understand the potential gains from improved market integration as well as the potential barriers to this integration. I study years (2016–2022) when wholesale electricity markets were rapidly changing as new renewable generators enter the market, which provides a policy-relevant context for understanding the current landscape for transmission infrastructure. I document several key facts.

First, I show that there are allocative inefficiencies in Midwestern United States electricity markets resulting from spatial constraints that limit the ability of low-cost generators to serve the market. Second, I show that these allocative inefficiencies were historically low but rose rapidly over 2020–2022, in part because of the rise of wind generation—and the wind curtailments that have resulted from transmission lines not keeping pace with new renewables builds. Existing low-cost wind power could serve more customers if there were more transmission capacity. For 2022, I document costs of more than \$2 billion from regional constraints in the MISO and SPP markets. This is a lower bound since it does not include very localized transmission congestion, reliability impacts, or long-term investment impacts. Future effects will also of course depend on the future paths of natural gas prices.

A sizable reallocation of generation is possible just with pairwise integration of a few key regions. Moreover, calculations in the Supplemental Appendix show that, compared to the magnitude of costs for a large transmission project (CREZ) in Texas, pairwise integration frequently passes a rough cost-benefit test.

Third, I show that while fossil net revenues have eroded as new wind has entered, fossil incumbents have been partly protected by regional constraints. Put differently, as low-cost wind enters, the incentive for some fossil incumbents (those in load pockets) to block new transmission lines (and other market integration reforms) rises. We might thus expect incumbent opposition to new transmission to grow in parts of the country where it would open generators up to competition. The magnitudes of these incentives are large: hundreds of millions of dollars annually for individual firms.

Others have pointed to flaws in the way transmission lines are planned, permitted, sited, and built in the United States. Davis, Hausman, and Rose (2023) provide an overview, and Klass et al. (2022); Peskoe (2023); and Macey, Welton, and Wiseman (2024) detail the specific law and governance structures that impact grid reliability and transmission planning. Klass et al. (2022) write that

behind many of the current laws, tariffs, and practices that impede a clean, reliable energy future lies an RTO-governance model where incumbents hold outsized sway and, at times, have structural interests against the build-out of clean energy (pp. 1062–63).

They also argue that MISO and SPP have some of the *better* processes for interregional transmission planning and renewables integration, suggesting that the cases I study may understate the magnitude of the problem relative to other regions.

Indeed, descriptive evidence from other regions suggests that transmission congestion and associated curtailments are large problems. Data from Millstein, O’Shaughnessy, and Wiser (2024) show wide spatial variation in wholesale electricity prices across the United States from 2016 through 2023. This is true across several metrics: the average hourly price, the frequency of negative-price occurrences, and the average price across the 100 highest-price hours. And Davis, Hausman, and Rose (2023) and Department of Energy (2023a) show that the Midwest is not alone in experiencing growing renewables curtailment. As Millstein et al. (2021) note, curtailments are not in of themselves problematic, if they reflect high renewables penetration as opposed to transmission congestion. However, curtailments to date are widely seen as resulting from congestion (Energy Information Administration 2023f; Wilson 2023; Potomac Economics 2024).

Future research could expand on my results in several ways. It could be useful to look at emissions outcomes across my counterfactuals. In most years, my main counterfactual predicts somewhat *higher* CO₂ emissions had the market been integrated, but more important for emissions outcomes is the long-run effect on fossil plant retirements and on new wind entry.⁵³ A dynamic model, along the lines of Linn and McCormack (2019); Gonzales, Ito, and Reguant (2023); or Gowrisankaran, Langer, and Reguant (2024) could be used to study these questions. Relatedly, it should not be forgotten that another aspect of the transmission network is the interconnection queue for new wind sites, which has faced a related but separate set of problems (Rand et al. 2022; Johnston, Yifei, and Yang 2023; Mays 2023).

⁵³In my sample, this is a result of coal displacing natural gas, combined with coal’s high and unpriced CO₂ emissions. Eliminating curtailments reduces CO₂ emissions, but the effect is smaller for my time period than is the coal versus gas effect.

Future research could also expand the scope of my analysis by incorporating reliability impacts. The existing transmission network to some extent reflects the fact that grid operators have historically prioritized reliability when planning transmission upgrades. Nonetheless, some have argued that winter storms Uri and Elliott—in 2021 and 2022—have demonstrated the need for greater interregional transmission lines to storm-proof the grid (Goggin and Schneider 2022; Goggin and Zimmerman 2023a). It is possible that reliability benefits are as large, or even larger than, the allocative efficiency benefits that I quantify.

Finally, additional research on the cases in which incumbent utilities have tried to block new lines would be useful both for understanding how widespread such cases may be and what governance reforms might better align transmission planning with the interests of society at large. Related work in economics on climate policy has examined lobbying activity and campaign contributions in the United States and Europe (Holland et al. 2015; Meng and Rode 2019; Rode 2021). For the case of transmission planning, research largely comes from the law literature. Specific tactics a utility might use to favor its interests are detailed most extensively in Peskoe (2023) but also in Welton (2021); Kovvali and Macey (2023); Ansolabehere et al. (2024a,b). Some of the tactics named include leveraging Regional Transmission Organization voting rules to disadvantage new transmission development, preempting interregional lines with a utility's own localized transmission or generation projects, or funding grassroots opposition groups. The literature has examined numerous case studies; broader quantitative evidence is still lacking. That may be difficult to obtain: The activities of stakeholders are hard to observe. Indeed, Macey, Welton, and Wiseman (2024) argue that current governance structures “allow large, entrenched actors to implement their agendas across institutions in opaque and unaccountable ways” (p. 171).

Analysts have proposed a suite of reforms to transmission planning, permitting, and siting.⁵⁴ Perhaps most ambitious are the proposals for centralized federal authority over transmission planning and operations. Smaller-scale reforms include changes to FERC's processes and updated guidelines for regional organizations. Alternatives to building new transmission lines have also been proposed: relying on batteries and other forms of storage instead, building renewables at such a large scale that major new interregional transmission is not needed, or upgrading existing corridors rather than building new lines. And in addition to calls for physical build-out of the transmission network, there has been a push for the removal of institutional constraints across markets. What the results of this paper suggest is that anticipating the incentives of incumbent utilities in *any* new or modified transmission process will be important, irrespective of which policy reforms ultimately move forward. That is, reforms that do not address underlying governance issues—arising from utility incentives that are not matched to those of society as a whole—may be less likely to deliver the end results that policymakers desire.

My results relate to crucial questions about who will win and who will lose in an energy transition and how this impacts the political economy of decarbonization.

⁵⁴ Examples include Welton (2021); Klass et al. (2022); Kovvali and Macey (2023); Peskoe (2023); Energy and Environmental Economics Inc. (2024); Macey, Welton, and Wiseman (2024); Simeone and Rose (2024); and Welton (2024).

As Colgan, Green, and Hale (2021) write, “Climate change and climate policy are altering the value of assets, from real estate and power plants to the labor of fossil fuel workers. This process generates increasingly contentious political battles over which assets, professions, and communities will retain value or even survive at all” (p. 587). The policy question is whether the current legal, regulatory, and policymaking procedures adequately represent the interests of society as a whole or whether there are opportunities for those who stand to lose to bend the process to their will.

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