Market Structure and Transmission Investments in U.S. Electricity Markets*

Yifei Liu†

University of Wisconsin-Madison

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Abstract

Meeting the growing demand for electricity and supporting the decarbonization of the power sector requires substantial investment in transmission infrastructure. This paper evaluates the impact of a specific market design, known as "market dispatch," on such investment. Traditionally, a single, regulated utility company supplied electricity within a region. In the late 1990s, however, many regions in the United States began shifting toward a market dispatch design. In the market dispatch system, electricity generation is supplied by multiple utility companies, and each company's generation quantity is determined through competitive auctions. Despite this shift in system design, the transmission operations of these utilities continued to be regulated on a cost-of-service basis. This paper first presents a conceptual model demonstrating that the market dispatch system alters utilities' incentives to invest in electricity transmission, though the overall effect on investment is theoretically ambiguous. I then employ a dynamic difference-in-differences design to estimate the empirical impact of market dispatch adoption on transmission investment, leveraging the staggered roll-out of market dispatch across regions. The results indicate that adopting this system leads to an average increase of $36 million in transmission investment by utilities—nearly 50% of mean investment levels. However, I find no robust evidence that utilities spend more on high-voltage transmission lines at or above 345 kV, which are pivotal for reducing greenhouse gas emissions.

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†Department of Agricultural and Applied Economics, University of Wisconsin-Madison, Madison, WI 53706; yifei.violet.liu@wisc.edu.

1 Introduction

U.S. electricity demand is projected to grow by 15.8 percent by 2029, driven by accelerating electrification across multiple sectors(Walton, 2024). At the same time, the country aims to achieve Net-Zero Greenhouse Gas Emissions by 2050[1]. Meeting rising demand while decarbonizing the power sector will require large-scale investment in the U.S. transmission network. Upgrading this infrastructure network is critical for maintaining electricity system reliability, managing shifting demand patterns, alleviating system congestion, and enabling a cost-effective energy transition by integrating geographically dispersed, low-cost renewable resources (Larson et al., 2021; Weiss et al., 2019; Department Of Energy, nd). Economic research further also shows that transmission investments preserve competitive electricity markets by mitigating market power and reducing wholesale prices (Davis and Hausman, 2016; Woerman, 2019; Ryan, 2021; Gonzales et al., 2022; Doshi, 2023).

Despite these imperatives, current investment levels in electricity transmission fall far short of what is necessary to achieve the 2050 Net-Zero target (Department Of Energy, nd; Pfeifenberger et al., 2019). The economics literature has highlighted several potential barriers to adequate transmission investment, including regulatory fragmentation, cost allocation disputes, and permitting delays (Wolak, 2010; Davis et al., 2023). However, empirical research quantifying the specific mechanisms that drive or hinder transmission investment remains limited.

This paper investigates how implementing a specific market design, known as “market dispatch”, influences investments in electricity transmission infrastructure. Traditionally, electricity supply in a region was provided by regulated monopolists. In the late 1990s, many U.S. regions transitioned to market dispatch systems, where multiple utilities supply electricity to wholesale markets through centralized auctions. Both regulatory regimes co-exist today across the United States. This study focuses on profit-driven Investor-Owned Utilities (hereinafter ”Utilities”), which control approximately 80% of the nation’s transmission infrastructure and often operate across the entire electricity supply chain, including

[1] The Net-Zero Greenhouse Gas Emission scheme aims to reduce the amount of greenhouse gases emitted into the atmosphere to a level where any remaining emissions are offset by carbon capture and sequestration (Office of the Federal Chief Sustainability Officer, nd)

generation, transmission, and distribution. The analysis explores how utilities' profit motives and generation ownership affect their transmission investment decisions under market dispatch relative to traditional regulatory system.

I first use a conceptual model to demonstrate that market dispatch changes utilities' incentives to invest in electricity transmission, and the overall effect on investment is theoretically ambiguous. Under traditional regulatory system, utilities are attracted to capital-intensive projects due to rate-of-return payments, a regulatory framework that sets prices utilities can charge across the entire electricity supply chain (Averch and Johnson, 1962). In market dispatch systems, utilities continue to receive rate-of-return payments for transmission assets while deriving part of their generation revenue from wholesale electricity sales. This transition compels utilities to reconsider their transmission investment strategies.

The conceptual model highlights two competing incentives. On one hand, wholesale electricity markets encourage inter-regional trade (Mansur and White, 2012; Cicala, 2022a), which can increase demand for transmission capacity and improve utilities' prospects for securing favorable regulated returns on transmission investments. This dynamic gives utilities a financial incentive to expand transmission infrastructure as a profit-maximizing strategy. On the other hand, transmission constraints in wholesale markets can fragment geographic competition, allowing utilities to raise electricity prices by exercising market power (Borenstein et al., 2000; Joskow and Tirole, 2005; Woerman, 2019). In this context, utilities may seek to preserve generation-based profits by strategically limiting transmission investment. Because these incentives operate in opposite directions, and given the presence of investment frictions and uncertainty in real-time markets, the model predicts that the overall effect of market dispatch on transmission investment is theoretically ambiguous.

I next leverage the staggered rollout of market dispatch and employ a dynamic difference-in-differences design to estimate the impact of market dispatch adoption on transmission investment. Adoption occurs through a distinct event: the transfer of transmission system control to an Independent System Operator (ISO), which then manages centralized electricity generation auctions. This approach builds on Cicala (2022a), who also leverages the staggered transition to study market liberalization's impact on electricity generation costs. To address concerns regarding time-varying treatment effects and problematic comparisons between treatment and control groups under staggered rollouts, I employ the event-study estimator from Callaway and Sant'Anna (2021). The analysis examines transmission investment effects in utilities subject to market dispatch compared to those not yet adopting market dispatch, focusing on two key outcomes: total transmission investment and investment in high-voltage infrastructure. Throughout this paper, "high-voltage" refers to transmission lines with voltages of 345kV or higher[2]. The first outcome captures direct impacts on investment, while the second outcome illuminates the specific type of infrastructure being prioritized in investment.

A potential threat to the causal validity of my analysis is an undetected violation of the parallel trends assumption. In difference-in-differences applications, researchers commonly test for pre-treatment trends to assess the plausibility of this assumption. However, recent work suggests that such tests may lack power and robustness, potentially failing to detect meaningful violations (Freyaldenhoven et al., 2019; Bilinski and Hatfield, 2018; Kahn-Lang and Lang, 2020; Roth, 2022). This concern is relevant in my empirical setting, where noisy pre-treatment data may limit the ability to reject the presence of differential trends conclusively. To address this issue, I implement sensitivity analyses following Rambachan and Roth (2023) to characterize the range of credible causal conclusions under potential deviations from parallel trends.

I find that market dispatch adoption leads to a persistent increase in overall investment among utilities, but not necessarily in high-voltage transmission projects, which are considered more effective at facilitating decarbonization of the electricity grid. Analyzing a dataset of 213 utilities across the U.S. from 1995 to 2020, I observe an average investment increase of $36 million, or approximately 50% above the mean investment level identified from the baseline specification. These results remain robust through sensitivity analyses, tolerating up to a deviation of $\pm 70\%$ from a linear projection of pre-treatment trends. However, there is no conclusive evidence that these increased investments are directed towards high-voltage transmission lines, crucial for mitigating greenhouse gas emissions. The baseline specification does not show an effect of market dispatch on investment in high-voltage lines. When controlling for the utility's business portfolio, there is a potential increase of

[2]In the U.S., the American National Standards Institute (ANSI) establishes nominal voltage ratings. It defines high voltage as 115kV to 230kV, extra high voltage as 345kV to 765kV.

$6.74 million in high-voltage line investments. Nevertheless, sensitivity analysis indicates that this result is robust only to deviations of up to $\pm3\%$ from the pre-treatment trend, suggesting that minimal non-linearity in the pre-trend difference is necessary to reject the null effect on high-voltage investment.

Related Literature

This project contributes to three areas of existing literature and an ongoing policy discussion. First, it evaluates the advantages of market dispatch system over traditional regulatory system in the electricity sector. Mansur and White (2012) demonstrated that transitioning to organized auction markets increases efficiency by reallocating production from high-cost to low-cost plants and improving trade through better information on grid congestion. The benefits significantly outweigh the costs of implementing auction markets. Cicala (2022a) further examined nationwide effects, finding that market dispatch reduces production costs and enables substantial regional electricity trade. While existing research has focused primarily on the effects of market dispatch on the generation sector, this project extends the analytical framework to the transmission sector. By doing so, it broadens our understanding of how market design influences infrastructure investment across the electricity supply chain.

Second, this project adds to our understanding of how regulatory reforms influence investment behavior in electricity markets. Joskow (1997) suggested that reforms such as electricity market restructuring could lead to long-term shifts in capital investment and potentially improve efficiency significantly. Jha (2020) explored the short-term effects of output price regulation on working capital, particularly coal stockpiles at U.S. power plants, finding that regulated plants tend to stockpile more coal than those under market prices due to regulatory distortions that increase coal purchasing costs. Cicala (2022b) examined the long-term effects of these reforms, specifically how the divestiture of power plants affects utilities, discovering that utilities with transmission and distribution operations increase their regulated capital stocks to compensate for the loss of generation assets. This suggests that efficiency improvements in plant operations may not fully reach end consumers if parts of the electricity supply chain remain under rate-of-service regulation. Fowlie (2010) examined the impact of deregulation on investments in pollution control equipment at power plants, revealing that deregulated plants in restructured markets tend to invest less in expensive environmental compliance methods than those in regulated or publicly owned settings. These studies lay the groundwork for analyzing the impact of electricity regulatory reforms on investment scale. Building on this foundation, I explore the effects of changes in market structure on utilities' transmission investment decisions, shifting focus from generator divestiture prompted by restructuring reforms to the implementation of market dispatch.

Third, this project adds to the broader body of research on the effects of electricity regulatory reform. Studies have demonstrated that price regulation influences firms' production decisions and improves efficiency at the plant level across various dimensions, including fuel procurement (Cicala, 2015; Chan et al., 2017; Chu et al., 2017; Di Maria et al., 2018; Knittel et al., 2019; Cicala, 2021), labor allocation (Fabrizio et al., 2007), maintenance scheduling, and operational efficiency (Davis and Wolfram, 2012). Consistent with these studies, my work leverages rich variation resulting from structural changes in regulatory policies within the electricity sector, extending this analysis to transmission investment decisions.

Finally, this project contributes to ongoing policy discussions regarding challenges in planning, constructing, and motivating utilities to invest in large-scale transmission projects. This policy debate, which emerged decades ago due to concerns about grid reliability, has received heightened attention as the country seeks to pursue a low-carbon electricity grid. Several factors have been extensively discussed in this context. The siting and permitting process often results in significant delays and cancellations of transmission projects (Reed, 2021). Cost allocation and financing remain complicated, especially for regional transmission projects (Morehouse, 2021). Transmission owners often lack long-term planning perspectives and favor smaller-scale local projects due to political factors (Brown, 2021; Peskoe, 2022; Lacey, 2022). This project adds to the discussion by exploring market dispatch as a mechanism that explains observed patterns in transmission expansions. There is also an ongoing debate among utilities in Western states regarding the decision to join ISOs and adopt market dispatch systems. My analysis provides insights into the causal implications of market dispatch for transmission investment trajectories, informing this important policy decision.

2 Background

2.1 Operational systems in the U.S. electricity market

The U.S. electricity market currently has two operational systems: the traditional system and the market dispatch system.

Until the late 1990s, the traditional system, based on a local monopoly structure, dominated the U.S. electricity sector. Electric utilities, whether investor-owned, publicly owned, or cooperatives, were vertically integrated, controlling the entire electricity supply chain from generation to distribution within their designated areas. Local monopolies served as “balancing authorities”, ensuring supply met demand within their regions. They also managed the transmission system and distributed power within a Power Control Area (PCA), typically coinciding with their service territory. This system featured decentralized, bilateral trading and relied on engineering estimates for decision-making and power management within each utility’s service area.

The market dispatch system revolutionizes this approach by centralizing electricity trading within a wholesale market. This system is facilitated by ISOs, nonprofit entities that oversee auction-based electricity dispatch across multiple PCAs. Utilities participate in these auctions, submitting bids for their generation units. The ISO then dispatches electricity from the lowest to the highest bids to meet demand. The outcomes of these auctions set financial commitments for generators, who must supply the agreed amount of electricity or buy it at the real-time price if they fall short. ISOs also control and operate the transmission system for electricity delivery. The dispatch decisions incorporate price dynamics and transmission constraints, especially in scenarios of grid congestion.

2.2 Decision to Adopt Market Dispatch

Adopting a market dispatch system is a discrete event when the “balancing authority” in a PCA hands control of the transmission system to an ISO, which then dispatches generation through the market. This shift is not automatic but decided individually by utilities based on many factors, including technical challenges, political and business concerns, and historical considerations.

Technical challenges arise from the need to ensure non-discriminatory access to the transmission system as mandated by Order 888 and Order 889. In particular, when utilities must facilitate electricity transactions that require traversing their networks, either incoming from or outgoing to other utilities (Commission et al., 1996). The difficulty of handling these transactions varies by region, potentially influencing the decision to adopt market dispatch. In the Eastern Interconnection, fewer utilities mean fewer challenges, whereas in the Western Interconnection, the generally looser trade makes these challenges less acute.

From a political standpoint, some state commissions have been wary of ISO integration, fearing it might strip them of control over energy rates due to changes in fuel cost accounting and transmission cost allocation (Andrejasich, 2017). This concern extends to being exposed to extensive oversight by FERC and losing their regulatory autonomy. Additionally, there is anxiety that joining an ISO might reduce states' influences on system reliability (Gifford and Larson, 2023). From a business viewpoint, some utilities are apprehensive that ISO membership could restrict their operational freedom and possibly favor the ISO over the utilities themselves (Downs and Driver, 1998). These considerations are likely to impact the decision to transition to market dispatch.

A utility's history with power pools, which sometimes evolved into ISOs, can influence deciding whether to join an ISO and adopt market dispatch. These power pools were initially created to facilitate power exchanges between utilities. They often adapt and modify their foundational rules and procedures as they transform into ISOs. This historical context can make integration into an ISO a smoother process for some utilities, while others may choose not to join (Warwick, 2002).

Based on my understanding of the market dispatch adoption process, complex and multifaceted considerations support the decision to adopt. However, regulatory reports or discussions do not suggest that the decision is directly linked to utilities' perceptions of their future transmission investments or their potential profits from these investments.

3 Conceptual Model

This simple conceptual model demonstrates utilities' decision-making process regarding transmission infrastructure investments, emphasizing their objectives within the market dispatch system. Before detailing the mathematical model of a utility's problem in this system, I will first compare utilities' profit functions under market dispatch and traditional operational systems.

3.1 Profit Function

Utilities tend to operate in several segments of the electricity supply chain, creating multiple revenue streams. Their profit functions differ under a market dispatch system from those under a traditional operational system.

In the traditional system, utilities profit from rate-of-return regulation, a regulatory framework that allows utilities to charge customers for the costs of building, operating, and maintaining electricity infrastructure, as well as a reasonable rate of return on capital investments to compensate their shareholders for investment risks. While this framework ensures a stable revenue stream, it has been criticized for incentivizing utilities to prioritize capital-intensive projects (Averch and Johnson, 1962). The rate of return is overseen by federal or state regulatory bodies, and any changes in rate cases need to undergo a rigorous and timely process through rate case filing. Rate cases changed are typically initiated due to anticipated revenue shortfalls and insufficient rates of return (Warwick, 2002; Rglowienka, 2018). Historically, asking for rate cases change to make new capital investment needs to be centered around concerns out of reliability (Lowrey, 2023). Therefore, there is little concern about the effect of utilities' anticipation on transmission investment prior to market dispatch in my empirical context.

Under the market dispatch system, utilities navigate a more complex revenue landscape. They gain from wholesale electricity sales and rate-of-return regulation, with the latter's calculations incorporating earnings from wholesale market sales. Utilities profit from selling electricity into the wholesale market through their generation assets. The centralized auction system sets a market clearing price based on the bid of the marginal generator, paying this rate to all dispatched generators. Utilities may have the advantage of generating wholesale payments if their generators have low marginal costs and are located in areas with grid congestion. Their profits from transmission investments remain consistent under the rate-of-return model.

3.2 Generation Portfolio

Utilities' energy portfolios within their generation sectors are heterogeneous due to past regulatory reforms or fuel choices.

Although utilities typically own the entire electricity supply chain, some do not own generators because deregulation in the late 1990s aimed to separate generation from transmission and distribution to prevent market power abuse. This deregulation led to the sale or transfer of generating assets, but the California energy crisis of 2000-2001 slowed further reforms (Fabrizio et al., 2007). Consequently, regulatory changes vary by state, with some partially deregulated and others unaffected. Moreover, deregulation only partially coincided with the shift to market dispatch, resulting in a mix of regulated and deregulated environments across the country. Large parts of the country that adopted the market dispatch system remain entirely rate-regulated. Take several ISOs as examples: the Southwest Power Pool (SPP) serves only traditional utilities, the Midcontinent Independent System Operator (MISO) has only one deregulated utility in its footprint, and half of the utilities under Pennsylvania-New Jersey-Maryland Interconnection (PJM) face traditional profit function.

Utilities predominantly rely on non-renewable power generation, such as coal and natural gas, and are reluctant to invest in renewable energy because of the additional costs. Owning generators with different fuels can lead to different positions in the auction dispatch, resulting in different profit margins.

3.3 The Utility's Problem Under The Market Dispatch System

This conceptual model builds upon a conventional approach to modeling firm behavior under regulatory constraints (Averch and Johnson, 1962) and integrates insights from the behavior of electric generators facing transmission constraints in the wholesale market (Ryan, 2021; Doshi, 2023). The model synthesizes profit streams by combining elements from both of these frameworks.

Suppose there are utilities $i \in \{1, ..., I\}$ in the market, and each owns a distinguished set of electricity generators $g \in \{1, ..., G\}$.

3.3.1 Rate-of-Return Payment

Utilities are permitted to earn rate-of-return payments on their capital assets. This model focuses on transmission assets and abstracts away from other capital investments. Utilities are assumed to produce a single homogeneous product: transmission service, denoted as z. The production of this service utilizes two inputs: λ, the quantity of transmission capital, and γ, the quantity of other inputs. The inverse demand function is represented by $p(z)$. The unit costs of transmission capital and other inputs are denoted by c_λ and c_γ, respectively. Additionally, δ signifies the depreciation rate of the capital, and r represents the discount rate. The allowed rate-of-return payment on capital is defined as $s = c_\lambda + v$, representing the cost recovery and a profit margin. It is further assumed that utilities can secure this rate-of-return on their capital investments for periods of $m \in \{1, ..., M\}$ years. Within this framework, $n \in \{1, ..., N\}$ denotes the number of transmission infrastructures actively accruing rate-of-return payments. The present value of rate-of-return payment on transmission capitals is:

$$\sum_{m=1}^{M} \sum_{n=1}^{N} \frac{\lambda_n s(1-\delta)^m}{(1+r)^m}, \tag{1}$$

subject to the regulatory constraint:

$$\frac{pz - c_\gamma \gamma}{\lambda} \leq c_\lambda + v = s. \tag{2}$$

Taking a first-order condition with respect to λ_n,

$$\sum_{m=1}^{M} \frac{s(1-\delta)^m}{(1+r)^m} \tag{3}$$

3.3.2 Wholesale Payment

Utilities can profit by selling electricity in the wholesale market under a market dispatch system. Let utility i simultaneously submit bids that aim to maximize profits for each generator g it owns, following Cournot's competition behavior. These bids specify a generator's intended production at various market prices, represented by a supply quantity vector q_g and a bid vector b_g. Given that real-time electricity demand is perfectly inelastic, the market equilibrium is determined on the supply side. Consequently, utilities respond to the residual demand — the total market demand minus the supply from competing generators. The market price is set such that total supply equals total demand. Each generator incurs a cost c_g per unit of electricity produced. The optimization problem of g finding the supply curve that maximizes its profit function is $\pi_g(p) = p \cdot q_g(p) - c_g(q_g(p))$.

Transmission constraints delineate localized markets, referred to as restricted market area A. In this context, the residual demand curve faced by generator g in market A is described by $q_g(p) = D_g^A(p|\sigma_{-g}, \mathcal{L})$, where $\mathcal{L}$ signifies the transmission constraints in the electricity grid. It is assumed that $\mathcal{L}$ is inversely related to the aggregate transmission capacities $\sum_{i=1}^{I} \lambda_i$ managed by all utilities and that the inverse residual demand is a function increasing with $\mathcal{L}$. This constraint dictates the specific market A in which power generators operate. Market A covers the entire electricity market in scenarios without binding constraints. However, with binding $\mathcal{L}$, the market divides into smaller segments, with A representing one such segment.

$\mathcal{L}$ also determines the possible connectivity of area A to others via unconstrained transmission lines, allowing for direct and indirect electricity flows, thereby defining an unconstrained region. Let $B_A(p|\mathcal{L})$ signify the unconstrained regions potentially interconnected with A, where electricity import and export are feasible. Let $F(B_A|p, \mathcal{L})$ represent the possible electricity flows. When prices rise in the region A, it attracts net supply from $B_A(p|\mathcal{L})$, which, in turn, triggers transmission constraints, effectively segregating A from a broader regional network. The residual demand generator g encounters in its region is influenced by import and export limitations imposed by $\mathcal{L}$ and bids from rival generators $q_k(p, \sigma_k)$, where $g \neq k$, within the same constrained area. Thus, the residual demand for generator g in region A can be articulated as

$$D_g^A(p \mid \sigma_{-g}, \mathcal{L}) = \sum_{k \neq g, k \in \mathcal{B}_A(p|\mathcal{L})} q_k(p, \sigma_j) - \mathcal{F}(\mathcal{B}_A \mid p, \mathcal{L}). \tag{4}$$

The price-dependent derivative of residual demand for generator g is thus given by

$$\frac{\partial D_g^A(p)}{\partial p} = \sum_{k \neq q, k \in \mathcal{B}_A(p|\mathcal{L})} \frac{\partial q_j\left(p, \sigma_K\right)}{\partial p}. \tag{5}$$

Utilities confront uncertainties when submitting bids b_g and q_g, particularly under transmission constraints $\mathcal{L}$, which introduce variability in the bid distribution σ_{-g} from competing generators. Given the expected distribution of demand, competing generators' bids, and transmission constraints, the profit function for each utility I through market dispatch is:

$$\sum_{g=1}^{G} \max_{q_g, b_g} \mathbf{E}_{\sigma_{-g}}[pD_g^A(p|\sigma_{-g}, \mathcal{L}) - c_g(q_g(p))], \tag{6}$$

subject to the capacity constraint:

$$0 \leq q_g \leq q_g^{capacity}. \tag{7}$$

Taking a first-order condition with respect to each bid price,

$$\mathbf{E}_{\sigma_{-g}}[\frac{\partial p}{\partial g}(q_g p + \frac{\partial D_g^A(p|\sigma_{-g}, \mathcal{L})}{\partial p}(p - c_g^{'}(q_g(p))]_{p=b_g} = 0. \tag{8}$$

This represents the optimal pricing strategy for generator g, where the utility establishes prices based on the marginal cost plus a markup. With a simplification assumption that generators face constant marginal cost $c_g^{'}(q_g(p) = C_g^{'}$ and have full information on other generator's strategy, this can be rewrite as:

$$p - C_g^{'} = -\frac{(q_g p)}{\partial D_g^A(p|\sigma_{-g}, \mathcal{L})/\partial p}. \tag{9}$$

The denominator is the slope of the residual demand curve, which influences the generator's markup strategy. A flatter residual demand curve implies a reduction in the optimal markups to be set by generators. A steeper residual demand curve suggests higher optimal markups.

The slope of the residual demand curve faced by generator g is ambiguous regarding how transmission constraint $\mathcal{L}$ changes. While the slope at a given price decreases as constraints increase, as Equation (4) indicated, the number of rival generators in the region $B_A(p|\mathcal{L})$, impacted by the constraints, also affects the negativity of the slope faced by generator g.

As transmission constraints bind more often, the set of unconstrained regions may change, and the equilibrium price distribution will also change. Generators may adjust their bid prices based on the residual demand slope within their price range, considering potential constraints rather than assuming an uncongested market scenario.

3.3.3 Integrating Rate-of-Return Payment and Wholesale Payment

With market dispatch, utilities aim to maximize profits by considering both the rate-of-return and wholesale payments. The objective function faced by each utility I is:

$$\sum_{m=1}^{M}\sum_{n=1}^{N}\frac{\lambda_n s(1-\delta)^m}{(1+r)^m}+\sum_{g=1}^{G}\max_{q_g,b_g}\mathbf{E}_{\sigma_{-g}}[pD_g^A(p|\sigma_{-g},\mathcal{L})-c_g(q_g(p))] \tag{10}$$

Here, utilities evaluate the profitability of two distinct avenues: transmission capital returns and wholesale market earnings. On the transmission side, it is unequivocal that increasing transmission infrastructure enhances profits under the rate-of-return payment as indicated above. However, on the wholesale market side, the impact of (λ and $\mathcal{L}$) on the generator's ability to set price markups is ambiguous due to the interplay between transmission capacity and residual demand. Consequently, utilities face strategic decisions regarding their focus: prioritizing profit through the transmission sector or generation sector.

3.4 Ambiguity in Investment Direction

The model above suggests that utilities assess the profitability of two avenues, involving a trade-off between investing in the transmission or generation sector. Below, I present evidence from academic research and industry reports to illustrate the trade-offs utilities encounter in reality and the ambiguity in choosing the investment direction after adopting market dispatch.

Utilities may prioritize maximizing wholesale payment from the generation sector by strategically reducing investment in transmission infrastructure. Grid constraints influence wholesale dispatch, and insufficient transmission capacity can create localized markets with reduced competition (Borenstein et al., 2000; Joskow and Tirole, 2005; Woerman, 2019). In such environments, utilities that own generators in congested or high-demand areas can exert market power and elevate prices by discouraging transmission expansion. The incentive to limit transmission is particularly strong when these generators are likely to set market clearing prices. Additionally, after the adoption of market dispatch, utilities face higher transaction costs when proposing large-scale transmission projects, which must undergo extensive stakeholder review and ISO board oversight. Together, these institutional frictions and profit motives may discourage utilities from pursuing transmission investments in favor of strategies that enhance returns from generation.

Utilities may prioritize the rate-of-return payment from the transmission section by increasing investments in transmission infrastructure. Research indicates that market dispatch encourages inter-regional electricity trading (Mansur and White, 2012; Cicala, 2022a), which can drive demand for transmission infrastructure and enhance investment returns. These dynamics can shift utilities' focus toward expanding transmission as a profit-generating strategy. The incentive is further strengthened by the role of ISOs, which coordinate regional transmission planning to maintain grid reliability. This planning process particularly benefits utilities without generation assets or those whose generators are typically dispatched later in the merit order[3], as they have fewer opportunities to profit directly from energy sales. However, transmission investments face significant barriers: projects are capital-intensive, take years to complete, and are subject to uncertainties in permitting, siting, and financing.

4 Data & Descriptive Statistics

I construct a comprehensive panel dataset on U.S. electricity transmission infrastructure spanning 1995 to 2020. The dataset includes information on market dispatch adoption, utility business portfolios, and electricity demand forecasts. To construct this dataset, I compile publicly available records maintained by the Federal Energy Regulatory Commission (FERC) and the Energy Information Administration (EIA), supplemented with online regulatory filings and data from the market intelligence platform S&P Global.

[3]Merit order describes the sequence in which power plants are designated to deliver power, based on the ascending order of their bids/prices.

4.1 Transmission Infrastructure Investment

My primary data source is FERC Form 1 - Electric Utility Annual Report. Any major utility operating under FERC jurisdiction must report their financial and operational status for oversight and for electric rate regulation[4]. The financial filing discloses information on capital stocks for transmission infrastructure. Additionally, the reports contain information on capital asset characteristics, such as transmission voltage, material, distance, etc. I extracted the filings from their legacy database hosted by the Public Utility Data Liberation (PUDL) (Selvans et al., 2020). The transmission capital stocks and assets will be the dependent variables in my empirical analysis.

I focus on newly constructed transmission assets, meticulously cataloged as "transmission line structures" in the FERC form. The data reports these structures as segments of larger transmission projects, connecting one substation to another. Financial figures capture solely the costs associated with these structures, deliberately omitting any expenses for constructing or enhancing substations. In this study, "transmission lines" are defined as networks designed for the bulk transfer of electricity, as opposed to lower voltage lines meant for voltage stepping down and local distribution. Figure 1 illustrates the trend in average transmission asset additions over time, whereas Figure 2 depicts the distribution of capital investment by transmission line structure. On average, transmission capital additions for all utilities in the dataset have increased fivefold. Meanwhile, although the median transmission investment is below 20 million dollars, the distribution of the investment is right-skewed. Figure 3 and Figure 4 reveal a consistent increase in transmission line expansions, particularly within the 115kV-345kV range, and a steadier rise in other voltage categories. The sharp increase in high-voltage lines above or equal to 345kV from 2011 to 2013 can be linked to large-scale, top-down transmission planning projects [5].

[4]Major utilities are defined as those that, in each of the past three calendar years, have: either total annual sales exceeding 1 million megawatt hours, annual sales for resale surpassing 100-megawatt hours, annual power exchanges delivered totaling over 500-megawatt hours, or annual wheeling for others exceeding 500-megawatt hours. I observed a slight fluctuation in the number of utilities reported to FERC, ranging from 192 to 229 utilities between 1994 and 2020.

[5]For example, there was the Competitive Renewable Energy Zones (CREZ) project in Texas, which was constructed over this period at a cost of approximately $6.8 billion. There were also multiple key interstate transmission projects in the western states, such as the Southwest Intertie Project linking southern Idaho

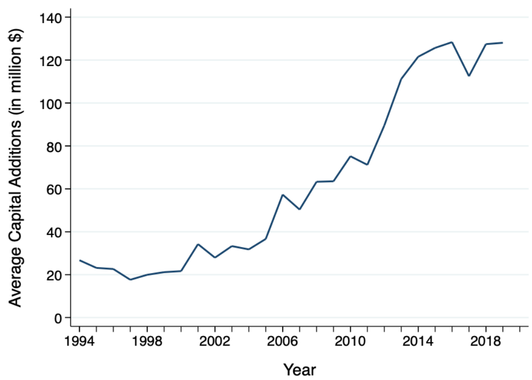


Figure 1: Average transmission capital additions across time

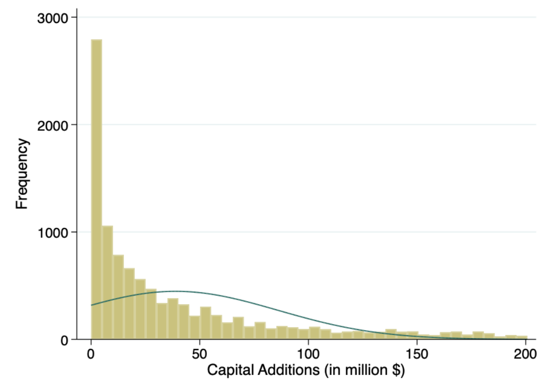


Figure 2: Transmission capital additions distribution

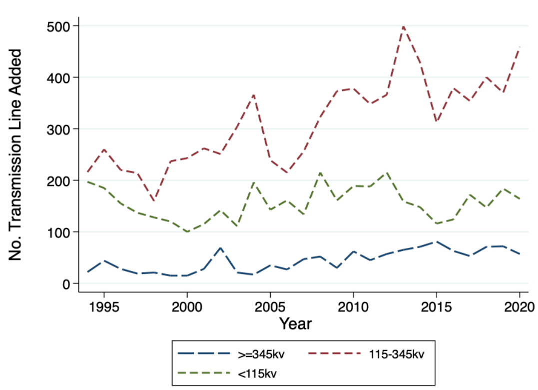


Figure 3: Number of newly constructed transmission lines across time

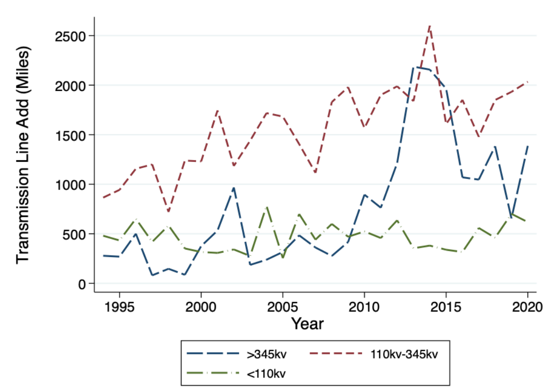


Figure 4: Length of newly constructed transmission lines across time

4.2 Market Dispatch Adoption

I compile data on market dispatch adoption, identifying when utilities begin participating and which Independent System Operator (ISO) assumes operational control of their transmission infrastructure. This information is gathered from online regulatory filings, supplemented by insights from Cicala (2022a) and cross-checked against ISO websites.

I utilize a data crosswalk by Cicala (2022a), which sets up Power Control Area (PCA) configurations at the 1999 level and connects these PCAs to constituent load and their associated market adoption events. Building on this linkage, I create a new crosswalk linking utilities to their respective PCAs in 1999 and then to the corresponding market adoption events. Around 60% of the utilities in my sample are successfully matched through the data crosswalk. For the remaining utilities, I identify the market dispatch adoption information using online regulatory filings. When utilities opt to participate as transmission operators or other market participants within ISOs, they must submit requests to FERC or public utility commissions. By analyzing historical filings, I determine the timing of market dispatch adoption for each utility that has adopted market dispatch. I cross-referenced my market dispatch data with ISO websites to validate it, since these sites maintain lists of current market participants.

Figure 5 illustrates the widespread adoption of market dispatch across the U.S. in 2020, with exceptions from Western Interconnection and small parts of the Eastern Interconnection. Figure 6 presents the number of utilities adopting market dispatch from 1997 to 2020. Within the sample period, there were 20 distinct instances of market dispatch adoption, with 80% of major utilities participating by 2019.

4.3 Utility Characteristics

I compile data on utility characteristics by drawing from EIA forms. The EIA861 dataset provides comprehensive information on utilities' involvement in generation, transmission, distribution, and marketing, allowing me to identify the types of businesses each utility operates in and the customer base each serves. The EIA860 dataset offers detailed insights

to central Nevada and the expansion of the Navajo Western Transmission System between Arizona and Nevada.

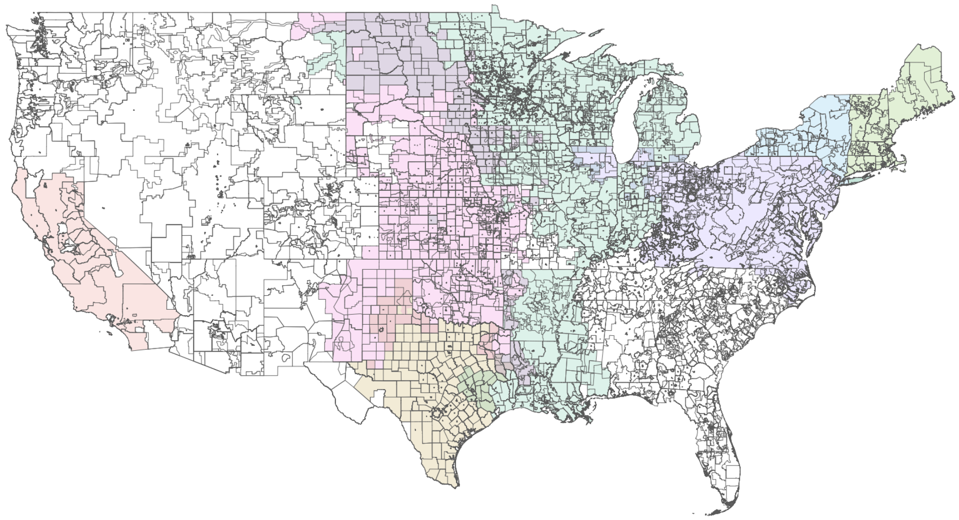


Figure 5: Utilities by market dispatch in 2020

Note: The color denotes Independent System Operator (ISO) regions, each managing auctions post-utility integration for market dispatch. On the graph, from left to right, CAISO is red, SPP is pink, ERCOT is yellow, MISO is green, PJM is purple, NYISO is blue, and NEISO is cyan—the underlying black boundaries approximate utility holding companies' locations and service areas.

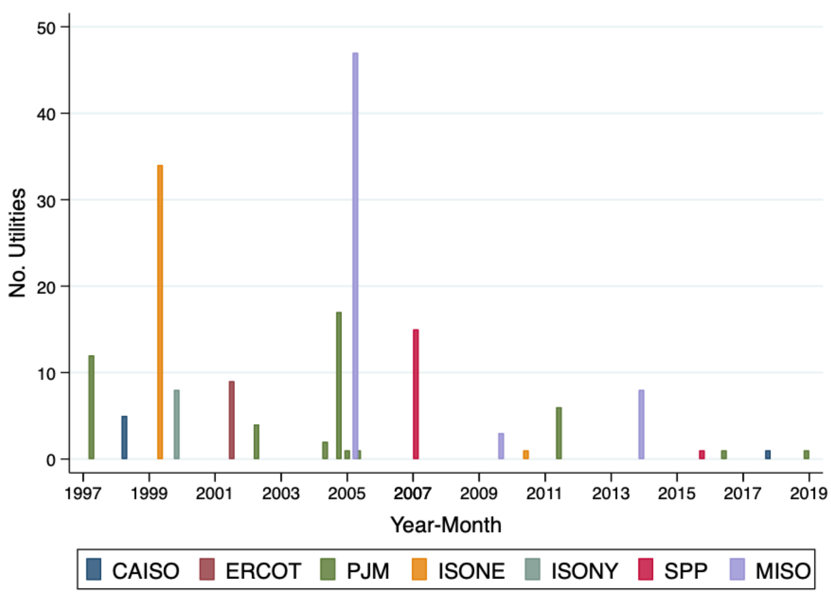


Figure 6: Number of utilities adopting market dispatch from 1997 to 2020

into power plants. By integrating this data with census population data at the zip code level, I determine the number of power plants each generator owns or operates and construct variables for power plants operating near demand centers. Utilities reporting to both FERC Form 1 and EIA forms, on average, operate or own 11 power generators, though the distribution is right-skewed, with a median of 7 generators. On average, a utility operates or owns 3 generators near demand centers, and 65% of utilities have at least one generator near demand centers[6]. I incorporate load and energy forecast data at the PCA level from S&P Global. This data is sourced from the North American Electric Reliability Council's Energy Supply & Demand and EIA411 filings, supplemented by FERC Form 714 filings. I analyze these load forecasts to discern whether utilities are more inclined to adopt market dispatch strategies in response to projected load growth.

4.4 Summary Statistics

Table 1 reports mean utility characteristics by market dispatch treatment status within my primary sample of 213 utilities, with the significance of mean differences indicated by p-values in the third column [7]. These metrics are benchmarked to 1995 before any market dispatch implementations. While the treated and never-treated groups are not perfectly balanced, critical features like customer base size and electricity demand forecast are well-balanced, implying that local electricity consumption patterns did not majorly influence market dispatch decisions. Utilities with a less diverse business portfolio, particularly those owning or operating fewer generators—especially near demand centers—were more inclined to adopt market dispatch. Additionally, utilities with initially lower transmission investments and shorter transmission line structures were more inclined to adopt market dispatch. However, the number of new transmission lines built in 1995 showed no significant difference between the treated and never-treated groups.

To account for baseline disparities, I use the not-yet-treated group as the baseline

[6]A generator is considered to be near demand centers if it is located in a zip code where the population is above the 75^{th} percentile compared to populations in zip codes of all other generators reported in the EIA 860 data.

[7]I need to update this table. In the DID analysis, I use the not-yet-treated as the control group. Therefore, summary statistics comparing the treated and the never-treated groups might be misleading.

Table 1: Summary Statistics

	Market Dispatch	Non-Market Dispatch	P-value
Customer base	651676.23	720191.74	0.57
Demand forecast	11.25	11.13	0.83
No. generators own or operate	14.70	23.94	0.00
No. generators near demand center	4.13	5.98	0.08
Transmission Investment ($ million)	28.55	51.81	0.00
Count of transmission line structure	2.00	2.76	0.45
Length of transmission line structure (miles)	5.19	9.65	0.09
Cost of transmission line structure ($ million)	1.60	4.20	0.00

All characteristics are measured as of a baseline year in 1995 prior to any of the market dispatch adoption.

control group in my empirical analysis. I incorporate utility-specific fixed effects to control for time-invariant unobserved differences in transmission investment across utilities. I use year fixed effects to account for macro shocks or trends that impact all utilities in the same year. I also examine various specifications to control the number of generators owned or operated at baseline and their proximity to demand centers, ensuring that the estimates account for observable baseline disparities.

5 Empirical Analysis

To assess the effect of market dispatch on transmission investments, I leverage the staggered and abrupt timing of market dispatch adoption. The transition involves a balancing authority within a PCA transferring control of the transmission system to an ISO, which then oversees market-based generation dispatch. I use a dynamic difference-in-differences (DID) strategy and an event study design within this staggered framework to contrast utilities undergoing market structure change with those experiencing no market change. The first objective of the analysis is to quantify the direct financial impact of market dispatch on transmission investment. The second goal is to identify the types of infrastructure investments utilities prioritize post-market dispatch, primarily focusing on whether higher-voltage transmissions are favored.

A central challenge in identifying causal effects is the presence of time-varying treatment effects. The influence of market dispatch might be realized incrementally, with its effects on investment varying across calendar years as utilities adjust their strategies in line with existing market conditions. These temporal fluctuations in treatment effects can bias the outcomes, a problem especially pronounced in staggered adoption frameworks. To tackle issues related to time-varying treatment effects and to avoid problematic comparisons between treatment and control groups, I use an event-study type estimator following Callaway and Sant'Anna (2021). Utilities that adopt market dispatch within the same year are grouped into the same cohort. Then, I obtained the average treatment effect on the treated(ATT) for members of each cohort in separate time periods. While the cohort-specific ATTs provide insights into the heterogeneity of treatment effects, I also generate an aggregated causal parameter that combines ATTs across all cohorts. The aggregated ATT is a weighted average of all cohort-specific ATTs, with the weights being the number of utilities in each cohort. This method assigns greater weight to cohorts with a larger number of utilities. To account for the disparities between the treated and never-treated groups, I use the not-yet-treated group as the baseline control group in my analysis.

My baseline econometric model is outlined as follows:

$$y_{i,t} = \beta D_{i,t} + \alpha_i + \theta_i + \gamma_t + \epsilon_{i,t}, \tag{11}$$

where $y_{i,t}$ is the amount of transmission investment (\$ million) OR the amount of high-voltage line investment (\$ million) for utility i in year t. $D_{i,t}$ is the treatment indicator which equals to 1 if utility i adopts market dispatch in year t. θ_i is the utility fixed effect to control for time-invariant unobserved differences across utilities. γ_t is the year fixed effect to capture time-specific trends. Standard errors are clustered at the utility level. The parameter of interest β reflects the average change in transmission investment or average change in high-voltage line investment.

I run two other specifications to account for additional confounding factors. First, I incorporate controls for the number of generators owned or operated and their proximity to demand centers to address potential imbalances mentioned earlier. Second, I execute a specification that includes an ISO-year fixed effect [8], to capture variations arising from utilities adopting market dispatch systems operated by different ISOs.

The event study model,

$$y_{i,t} = \sum_{l=-L}^{L} \delta_l \mathbf{1}\left[t - E_i = l\right] + \alpha_i + \theta_i + \gamma_t + \epsilon_{i,t}, \tag{12}$$

is analogous to the baseline DID model above, but the treatment effects are estimated using a standardized lead or lag relative to the time of market dispatch. The parameters of interest δ_l measure the effect of market dispatch l years after it was first introduced in year $t = E_i$. The fixed effects are the same as in the baseline specification above.

6 Results

I find that market dispatch adoption causes a persistent increase in investment, with an average increase of $36 million, or approximately 50% above the mean investment level. However, no conclusive evidence shows that the increased investments are allocated towards high-voltage transmission lines.

In this section, I present the Callaway & San'Anna estimates, taking a weighted average across cohorts as previously described. I will first display plots from the event study according to Eq. 12, summarizing the immediate and long-term effects using a 5-year window and a 10-year window. Subsequently, I introduce the main findings based on Eq. 11 and explore additional specifications. Utilities that have not yet adopted market dispatch serve as the control group.

[8]For integration into the Callaway and Sant'Anna (2021) event-study type estimator, I demean the dependent variables by ISO, calculate residuals, and then utilize these residuals as the new dependent variable. The definition of ISO is not time-varying

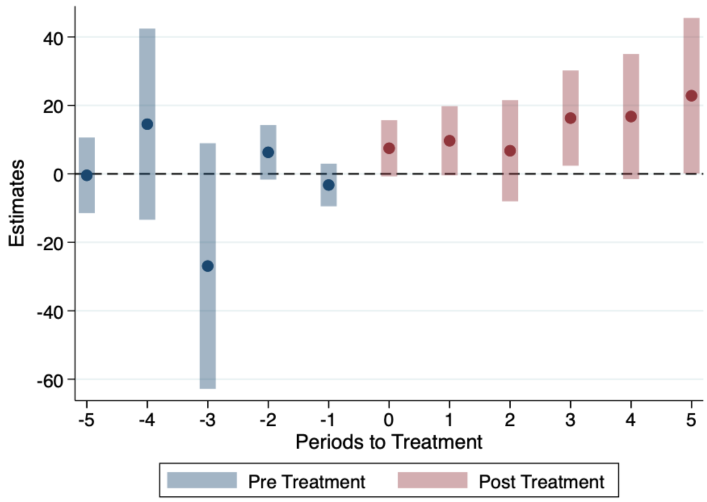
6.1 Event Study Results

The event study results suggest that market dispatch resulted in increased investment in transmission infrastructure over both 5- and 10-year horizons. The upper panel of Figure 7 presents the event study's results estimated over a 5-year window. These findings indicate that market dispatch, on average, boosted investment by $15.65 million, or approximately 22% of the mean of $70.51 million. The effect of the market dispatch treatment intensified over time. The lower panel, which evaluates the impact over a 10-year window, reveals more pronounced long-term effects. It shows an average increase of $26.92 million in investment, about 38% of the mean, highlighting a significant long-term effect. Figure 8 displays the event study results regarding the impact of market dispatch adoption on the investment of high-voltage lines, measured in million dollars, aiming to identify the types of infrastructure investments. The upper panel displays results estimated over a 5-year window, showing a $2.14 million increase. In contrast, the lower panel presents findings over a 10-year window, indicating a $5.51 million increase, compared to the mean of $6.93 million.

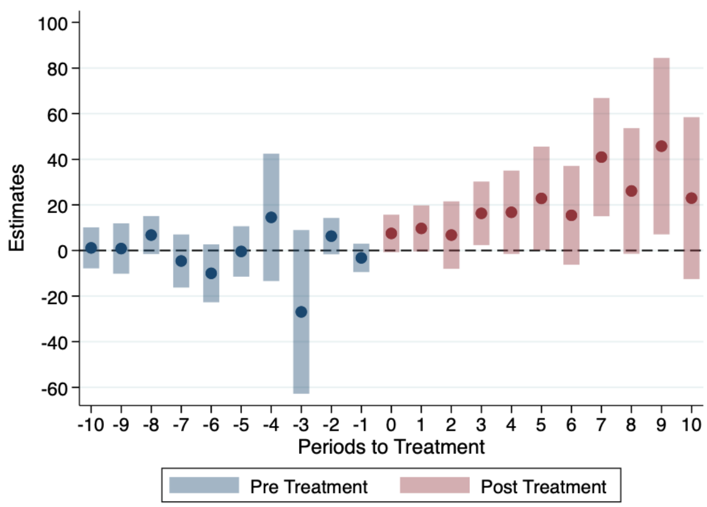
During the pre-treatment tests, the coefficients estimated on the leads of treatment do not significantly differ from zero, which corroborates that the pre-treatment outcome trends in both groups are comparable. This testing confirms that the control group is valid. However, the event study plots reveal noisy pre-trends with fluctuating point estimates and wide confidence intervals, raising concerns about potential violations of the parallel trend assumption. In section 7, I perform a thorough sensitivity analysis to establish robust confidence intervals that account for potential violations of the parallel trend assumptions and evaluate how varying assumptions about these deviations might impact my causal findings.

6.2 Difference-in-Differences Results

Table 2 presents the outcomes from the difference-in-differences estimation across various specifications. Column (1) adheres to the baseline equation Eq. 11, incorporating utility-specific and year fixed effects. Column (2) introduces additional controls for the business portfolio beyond the baseline, such as the number of generators each utility owns or operates and the number of generators near demand centers. Column (3) extends this analysis by



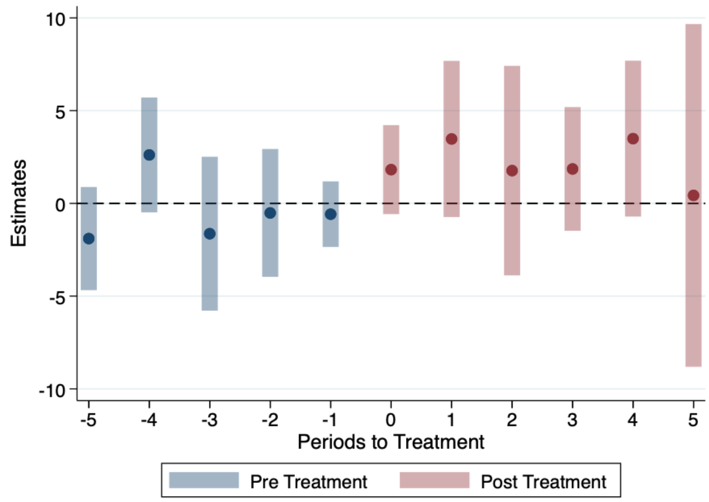
5-year window



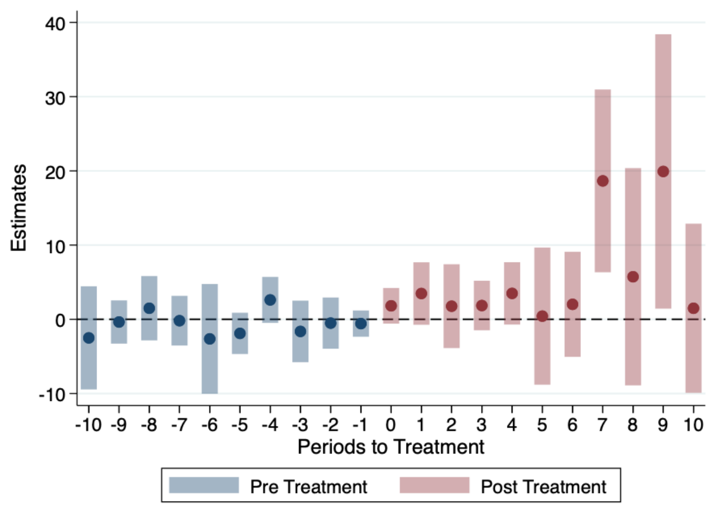
10-year window

Figure 7: Event studies - transmission investment

Note: Figure plots the estimates and 95% confidence intervals. The upper panel indicates the immediate effect of a 5-year window. The bottom panel indicates the long-term effect of a 10-year window. Each point indicates the change in transmission investment (in million dollars) in year l relative to year $l = 1$, the year before market dispatch adoption. Controls include utility fixed effect and year fixed effect. Standard errors are clustered at the utility level.



5-year window



10-year window

Figure 8: Event studies - investment of high-voltage investment

Note: Figure plots the estimates and 95% confidence intervals. The upper panel indicates the immediate effect of a 5-year window. The bottom panel indicates the long-term effect of a 10-year window. Each point indicates the change in transmission investment (in million dollars) in year l relative to year $l = 1$, the year before market dispatch adoption. Controls include utility fixed effect and year fixed effect. Standard errors are clustered at the utility level.

including an ISO-year fixed effect to refine the estimation further. It is important to highlight that the effect shown in Table 2 differs from the effect identified in the event-study specification due to the inclusion of the full panel data from 1995 to 2020 with a longer time horizon.

The adoption of market dispatch is associated with an increase in total transmission investment. Panel A details the impact on transmission investment, quantified in millions of dollars. According to the baseline model, the adoption of market dispatch is associated with a sustained increase in investment, averaging an increase of $36 million. This represents a rise of approximately 50% over the mean level of investment. Similar trends, with even greater magnitudes, are observed in the specifications shown in Columns (2) and (3). However, the analysis in these columns is constrained by the available data, limiting the sample to utilities consistently reporting to the EIA. Panel B examines the investment in high-voltage lines, revealing that market dispatch adoption preferentially boosts investment in high-voltage transmission compared to other voltage categories. The baseline specification in Column (1) shows no statistically significant effect. However, when controlling for the utility's business portfolio, the result shows an increase of $6.74 million, compared to an average of $6.23 million. Nonetheless, the findings related to high-voltage line proportions are notably sensitive to potential violations of the parallel trends assumption, rendering these conclusions less definitive. The implications of this sensitivity will be explored in section 7.

7 Sensitivity Analysis

The core principle of the difference-in-differences (DID) approach is based on the idea that, without intervention, the treated and control groups would exhibit parallel trends over time. Recent studies have raised issues regarding the reliability of pre-treatment trend tests, highlighting the possibility that significant trends before the treatment may not be accurately detected in the presence of volatile pre-treatment data. I have adopted the "honest approach" in Rambachan and Roth (2023) to infer and conduct a sensitivity analysis of confidence intervals for post-treatment point estimates. This involves allowing the possibility of divergent linear trends between the treated and the control units and

Table 2: Difference-in-difference Results

	(1)	(2)	(3)
A. Transmission investment			
Market Dispatch	35.28**	53.36***	53.50***
	(14.32)	(12.26)	(12.38)
Utility FE	X	X	X
Year FE	X	X	X
Utility business portfolio controls		X	X
ISO-Year FE			X
Obsservatioins	4,441	3,475	3,475
Mean of dep.	69.26	69.14	69.14
B. Investment of high-voltage lines			
Market Dispatch	4.99	6.74**	6.74**
	(3.33)	(2.94)	(2.93)
Utility FE	X	X	X
Year FE	X	X	X
Utility business portfolio controls		X	X
ISO-Year FE			X
Obsservatioins	4,249	3,340	3,340
Mean of dep.	6.93	6.23	6.23

Dep. var. for panel A is transmission investment, measured in million dollars. Dep. var. for panel B is the investment of high-voltage lines within the utility's newly constructed lines, measured in millions of dollars. SEs in parentheses; clustered by utility. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

assessing how such disparities affect the stability of my causal findings.

In my empirical setting, the validity of the parallel trends assumption is potentially undermined by secular trends that systematically correlate with the treatment, such as changes in regulatory philosophies or consumer preferences toward integrating electricity networks and the broader energy transition. For instance, regulatory bodies supporting electricity market integration will likely support market dispatch and may be more inclined to approve rate case upgrades for extensive electricity network expansions. Since these issues pertain to long-term trends expected to develop gradually, I test smoothness restrictions. This involves allowing the trend differential's slope to vary non-linearly across consecutive periods. The magnitude of alteration in the differential trend's slope between the treated and comparison groups over time is constrained by the following equation:

$$\Delta^{SD} := \{\delta : |(\delta_{t+1} - \delta_t) - (\delta_t - \delta_{t-1})| \leq M, \forall t\}, \tag{13}$$

where δ_t represents the trend disparity between the treated and control groups at time t. Here, M determines the maximum permissible deviation from the linear extrapolation. In the exceptional scenario where $M = 0, \Delta^{SD}(0)$ signifies that the trend difference between the groups is strictly linear.

I estimate the robust confidence intervals for both the baseline specification and the specification that controls for the utility's business portfolio. For the baseline specification, my focus is on the transmission investment results (Panel A, Column (1) of Table 2), as this is where I have previously found an effect. For the specification controlling the business portfolio, I perform sensitivity analysis on both transmission investment and high-voltage line investment results (Column (2) of Table 2), given that effects were found for both variables. The findings are displayed in Figure 9 and Figure 10, respectively. Specifically, in Figure 10, the left panel details the results of the transmission investment, while the right panel details the results of the investment in high-voltage lines.

First, let us focus on the sensitivity analysis for the baseline specification. To interpret the significance of M, I estimate a linear trend using only the pre-market dispatch event-study coefficients. The slope of the linear trend is -0.62 for transmission investment. As shown in Figure 9, the upper panel reveals a "breakdown" threshold of $M = 0.2$, allowing for a $\pm 32\%$ deviation from the linear trend per event-year. This analysis indicates that a substantial deviation from the estimated linear trend is required to negate the average effect of market dispatch on transmission investment. [9]

Then, let us focus on the sensitivity analysis of the specification controlling for the utility's business portfolio. The pre-treatment linear trend slopes are -0.41 for transmission investment and -0.03 for the investment of high-voltage lines. The sensitivity analysis also suggests significant deviations are needed to invalidate the dispatch effect on transmission investment. The left panel of Figure 10 shows a "breakdown" value of $M = 0.3$, allowing a $\pm 70\%$ deviation from the trend line per event-year. However, the analysis indicates that the results of investment in high-voltage lines are highly sensitive. The right panel shows a "breakdown" value of $M = 0.001$. Given a pre-trend linear slope of -0.03, the result remains valid only for deviations within $\pm 3\%$ of the pre-treatment trend. This means we can only reject a null effect if we believe the year-to-year linear extrapolation will not vary more than 3%.

In short, this sensitivity analysis projects the estimated linear trend into the post-market dispatch periods, evaluating the results' validity through an "honest" approach. The analysis confirms that my findings on total transmission investment remain robust against considerable deviations from pre-treatment linear extrapolation. However, the high-voltage transmission line investment results are sensitive to even minor deviations, putting the causal conclusions at risk.

[9] Defined as the average of the post-market dispatch event-study coefficients.

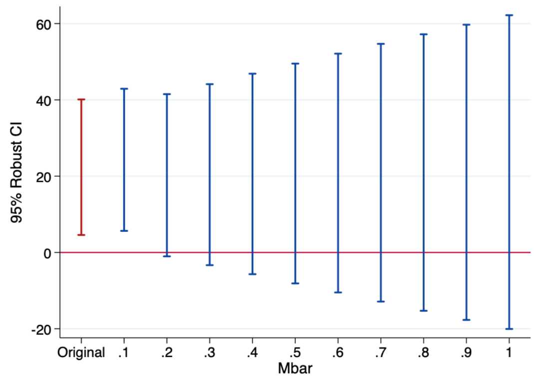


Figure 9: Honest approach to parallel trends - Baseline specification

Note: The panel reports the sensitivity of these results to the linear extrapolation of the pre-event coefficients using the honest approach to parallel trends of (Rambachan and Roth, 2023). This plot is the results of the baseline specification. The figure reports robust confidence intervals for transmission investment.

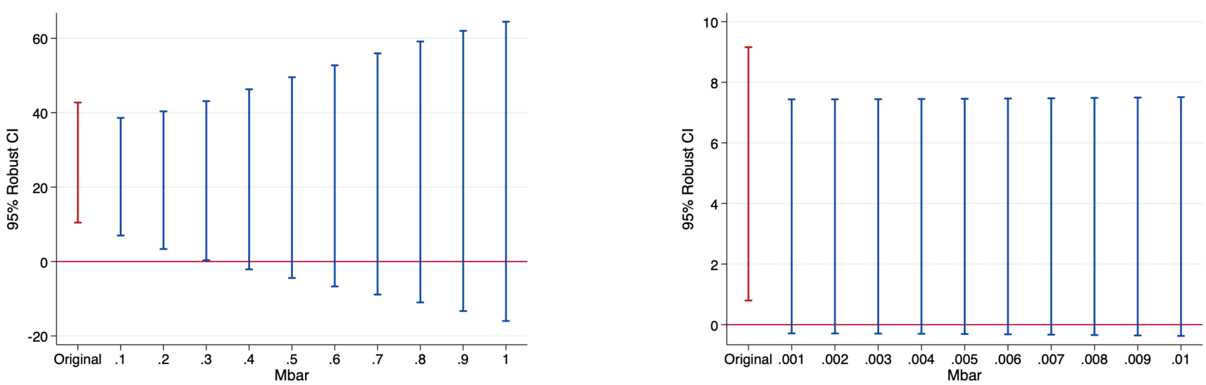


Figure 10: Honest approach to parallel trends - Specification with business portfolio controls

Note: The panel reports the sensitivity of these results to the linear extrapolation of the pre-event coefficients using the honest approach to parallel trends of (Rambachan and Roth, 2023). This plot is the results of the specification with business portfolio controls. The upper panel reports robust confidence intervals for transmission investment and the bottom panel reports robust confidence intervals for investment of high-voltage transmission lines.

8 Conclusion

In conclusion, this study investigates the effect of market dispatch adoption on electricity transmission investment by Investor-Owned Utilities in the United States. By utilizing a dynamic difference-in-differences approach and the staggered introduction of market dispatch, I find that market dispatch has significantly and persistently increased transmission investment by an average of $36 million, or about 50% above the mean. These results remain robust through sensitivity analyses, tolerating up to a deviation of ±70% from a linear projection of pre-treatment trends. However, this increase does not necessarily translate to investment in high-voltage transmission lines, typically considered pivotal for integrating the electricity grid and reducing greenhouse gas emissions. Sensitivity analyses indicate that findings regarding high-voltage transmission investment are highly sensitive to potential violations of parallel trend assumptions, leading to inconclusive results. This suggests that while market dispatch positively affects overall transmission investment, its impact on high-voltage transmission investment is less certain.

The findings have implications for policy debates on the need for transmission infrastructure development to support the reliability or decarbonization goals of the electricity grid. While market dispatch adoption represents a positive step that increases overall transmission investment, policymakers should not expect market reforms alone to generate the high-voltage transmission infrastructure necessary for large-scale renewable energy integration. Targeted policy interventions may be necessary to accelerate such development, including enhanced returns for interstate projects, streamlined permitting for high-voltage lines, and federal planning initiatives that complement regional market structures.

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