Money and Power*

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Abstract

Investments in electricity generation capacity incur substantial upfront costs and produce uncertain returns that can take years to materialize, making them highly dependent on external finance. We link loan-level regulatory data to power plant-level generation capacity and use two natural experiments to examine how financial frictions affect electricity producers' responses to taxes and subsidies. We find that increasing the cost of coal generation created spillovers through firms' internal capital markets and ultimately reduced investments in new solar capacity. We also find that subsidies designed to increase cash flows to early-stage projects disproportionately boosted solar capacity investments for financially constrained firms. These results highlight the importance of firms' financial frictions in understanding how policy can influence investments in electricity generation.

Keywords: Electric power, financial frictions, energy policy

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Conflict-of-interest disclosure statement

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I have nothing to disclose. The Y-14Q regulatory data used in this research are confidential and cannot be disclosed outside of the Federal Reserve Board.

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1 Introduction

Demand for electric power in the US is surging at a pace not seen since the 1980s. After remaining flat from 2005 to 2020, total electricity supply has since been growing 2% per year[1], and this pace is expected to almost double over the next 15 years amid demand for energy-intensive facilities like data centers.[2] Meeting this demand will require substantial additional investments in new generation capacity (U.S. Energy Information Administration, 2025a,c). Policy makers and regulators have a keen interest in understanding what kinds of new generation capacity will get built, who will build it, and how these decisions could be shaped by policy interventions.

Building the additional capacity necessary to meet this demand will incur massive upfront costs and take years before producing revenue.[3] These large initial outlays and delayed returns make electric power generation a textbook example of an industry in which investments are likely to exhibit strong dependence on external finance and sensitivity to cash flow (Fazzari, Hubbard, and Petersen, 1988). When investment is subject to financial frictions, the ultimate effects of any policy seeking to influence investment decisions will depend not only on how it affects the expected net present value of an investment, but also on how it affects the terms and quantity of external financing necessary to fund that investment. Despite the theoretical importance of this channel, data constraints have limited the ability of past work to analyze this mechanism directly.

In this paper, we combine confidential loan-level regulatory data with plant-level electricity generation activity to study how financial frictions distort firms' investments in new solar generation capacity. We analyze the two most consequential US policies targeting electricity generation in the past decade: the Mercury and Air Toxics Standards

[1] U.S. EIA (2025).

[2] Barth, Tai, Kaladiouk, and Heath (2025) projects that demand could increase by up to 3.5% per year, while U.S. DOE, LBNL (2024) estimate that energy demand from data centers will increase from 4.4% of total US demand in 2023 to 12% by 2028.

[3] This timeline includes not just the construction of the plant, which can take several years, but also the time to obtain regulatory approval for the project before construction starts and the time to connect to the grid once it is complete. See Johnston, Liu, and Yang (2023) for more details.

(MATS) in 2015 and the Inflation Reduction Act (IRA) in 2022. We focus on investments in new solar capacity because it was the single largest source of new capacity added during the past five years—accounting for more than one-third of all new generation capacity during that time—and is projected to account for more than half of all new capacity growth between now and 2030 (U.S. Energy Information Administration, 2025b). While this makes solar the most relevant outcome for the policies we analyze, the mechanism underlying our results is not unique to solar; we would expect any investments in new capacity to be distorted by financial frictions as long as they are expensive to build and slow to generate revenue.

We first show that MATS tightened firms' financial constraints and reduced their solar investments, even when the policy had, on paper, no statutory effect on solar power generation. MATS required roughly one half of coal-fired power plants to either install scrubbers or shut down, which predictably led to decreases in coal generation capacity for exposed firms. However, many of these same firms also operated solar generation in addition to their coal plants, and we find that MATS exposure caused these firms to cut back on new solar investments. This response was driven by a tightening in financial frictions that propagated through these firms' internal capital markets: MATS exposure increased firms' reliance on asset-backed borrowing for their fossil lines of business, which allowed them to maintain the quantity and cost of credit for these operations, but caused their solar projects to receive fewer loans and at higher interest rates. These results illustrate how financial frictions caused a policy whose direct effects focused exclusively on coal power plants to reduce firms' solar energy investments.

Next, we use the IRA to show that subsidies that increased cash flows for early-stage projects were more effective at reducing borrowing costs and stimulating solar investments for firms with greater financial constraints. While renewable energy investment tax credits existed before the IRA, an important provision of the law allowed all firms to sell previously nonrefundable tax credits to outside investors. Large firms with suffi-

cient taxable income to claim the credits had little to gain from this change, but it gave firms with little or no revenue additional up-front cash flows that eased their financial constraints. Consistent with this channel, we find larger post-IRA investments in solar capacity by smaller firms relative to larger ones, and that small firms also experienced larger reductions in their solar loans' interest rates, suggesting that financial constraints were an important determinant of these firms' investment decisions.

The massive scale of investment necessary to meet growing demand for electricity in the US means that questions about what kind of new capacity will meet this demand, where it gets built, and who operates it will have major implications for households, businesses, and government. Policy makers and regulators who seek to influence these investment decisions thus have a crucial interest in understanding what drives them and how they might respond to policy changes. We provide direct empirical evidence for the importance of financial frictions in determining energy producers' investment responses to potential policy and regulatory changes. While our results suggest failing to take these financial frictions into account can lead to unintended consequences—such as solar investment declining in response to restricting coal emissions—they also illustrate how the effect of subsidies can be amplified when they ease firms' financial constraints.

Related literature. Our paper contributes to two broad strands of literature. The first studies how taxes and subsidies designed to address externalities distort investment decisions in the presence of financial constraints and includes Tirole (2010), Hoffmann, Inderst, and Moslener (2017), Xu and Kim (2022), Martinsson, Sajtos, Strömberg, and Thomann (2024), and Döttling and Rola-Janicka (2025). We build on this work by providing direct empirical evidence for this channel in the context of electricity generation investments, which are subject to enormous economic and environmental externalities. The mechanism we study is also similar to the one in Lanteri and Rampini (2025), who analyze the role of financial constraints in determining the energy efficiency of firms' in-

vestments in the shipping industry.

The second strand of literature studies the determinants of firms' investments in energy generation capacity. Because energy is a critical input to virtually every part of the economy, electricity producers face a unique set of economic and regulatory incentives when making investment decisions. Past work including Johnston (2019), Hong, Kubik, and Shore (2023), and Sallee (2025) has studied how electric power generation has responded to a range of policy changes. Other papers focused on how taxes, subsidies, and research and development policies affect energy investment (Acemoglu, Aghion, Bursztyn, and Hemous (2012), Acemoglu, Akcigit, Hanley, and Kerr (2016), R.Brown, Martinsson, and Thomann (2022)). On this front, we provide empirical support for a "financial accelerator" mechanism, first described in Bernanke and Gertler (1989) and Kiyotaki and Moore (1997), in which the ultimate effects of any policy will depend on how it affects firms' financial constraints.

Our empirical evidence in the context of solar energy investment studies two policy changes: One which tightened financial constraints by raising costs and reducing incomes in their non-solar operations, and one which eased financial constraints by providing additional up-front cash flows via tax credits. The former finding is consistent with the mechanisms described in Lamont (1997) and Giroud and Mueller (2015), who show that firms' internal capital markets can propagate shocks across different lines of business in the presence of financial constraints. The latter finding supports Zwick and Mahon (2017), who show that bonus depreciation disproportionately boosted investment for small and financially constrained firms. We build on this work by highlighting the outsized importance of financial frictions in affecting investments in electricity generation capacity, whose investments are particularly sensitive to this channel.

This paper proceeds as follows. Section 2 provides background about how investments in energy capacity are financed and describes our data. Section 3 shows that MATS reduced exposed firms' solar investments by tightening their financial constraints rela-

tive to unaffected firms. Section 4 shows that the IRA boosted investments for small and new firms by easing their financial constraints relative to larger and older firms. Section 5 concludes.

2 Background and Data

2.1 Electricity finance background

Building electricity generation is capital intensive, and recouping the initial investment can take over a decade. As a result, financing costs play a large role in the total cost of building electricity generation. Solar and wind generation are typically more sensitive to financing costs than natural gas generation because a larger share of the cost is upfront.[4]

Electric power utilities rely far more on debt than firms in most other industries. For publicly traded firms, between 10 and 20 percent of this debt comes from banks according to S&P CapitalIQ, with the remainder coming primarily from the bond market.[5] However, bank loans have historically been the only source of debt available to smaller and privately held firms without access to bond markets, making them the marginal source of external finance for the most financially constrained firms.

Bank loans are also particularly important for "project finance." In contrast to a standard debt contract, in which a firm obtains a loan through some combination of collateral and its own overall creditworthiness, project finance involves the creation of a separate legal entity known as a special purpose vehicle whose primary function is to separate the financial benefits and risks of a specific project from those of its parent company. This approach insulates the parent company from the risks that the project will fail, but is generally more expensive for the borrower.

[4]Solar, wind, and natural gas are the three main types of generation that have been built over the last decade. Lazard (2025) shows that increasing debt costs have larger effects on solar than natural gas generator costs.

[5]We are in the process of extending our analysis to include firms' bond issuance.

2.2 Data

Our primary data source is Schedule H.1 of the Federal Reserve's Y-14Q regulatory data. These filings, which are mandatory for all loans of $1 million or more held on the balance sheets of large banks and bank holding companies,[6] are collected by the Federal Reserve and used for stress testing as part of the Comprehensive Capital and Analysis Review (CCAR) program. Collectively, these banks hold more than 85% of total US banking sector assets and represent more than two thirds of all commercial and industrial (C&I) loan volume.

The data include detailed firm and loan characteristics, including the loan's size, type, interest rate, maturity, collateral, and the bank's perceived probability of default. The data also include the borrower's name, location, industry, and taxpayer identification number (EIN), which we use to merge the data with other data sources. The data also include an indicator for the use of special purpose vehicles, allowing us to identify project finance loans (described in the previous section). Crucially, because these data include small private firms, they provide a comprehensive picture of how the quantity and terms of bank lending respond to policy changes.

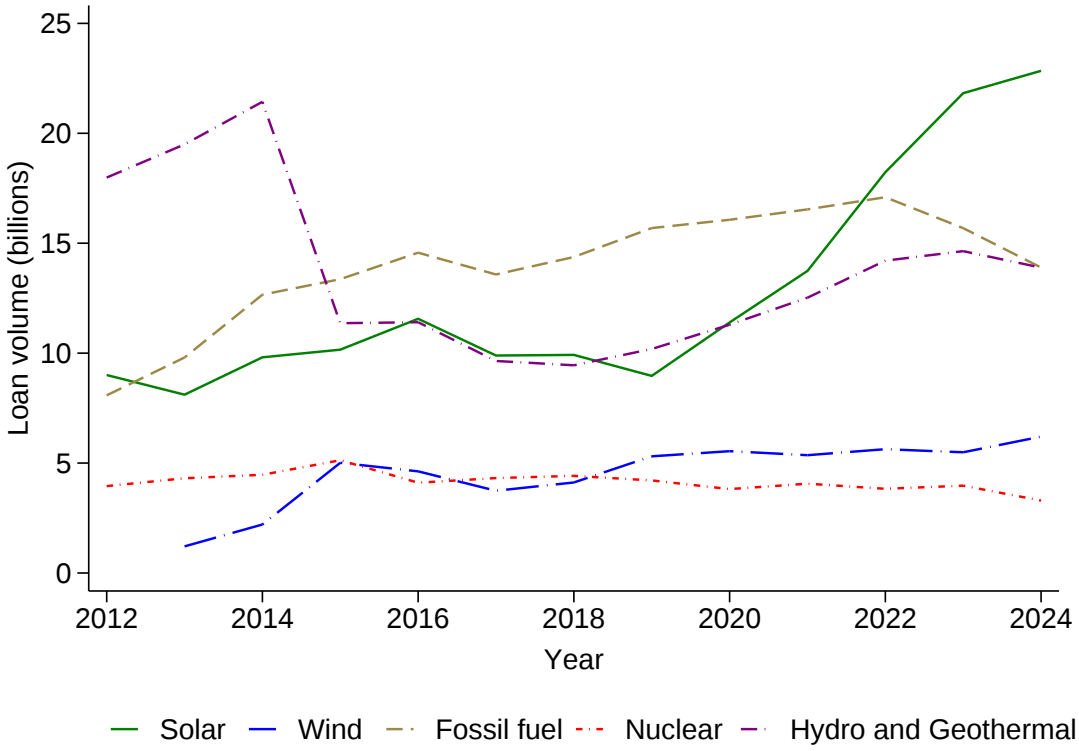
Loan volumes for the major electric power generation loan categories in the Y-14Q data are shown in figure 1.[7] Fossil fuel borrowing was between 10 and 15 billion over this time period. Borrowing for solar was around 10 billion until 2020 when it started to climb quickly. Figure 2 shows that increasing solar loan volumes since 2020 (left axis) are correlated with increases in solar capacity (right axis).

EIA 860 Our analysis also leverages Form EIA-860 data from the U.S. Energy Information Administration (EIA), which records annual information at the power plant generator level of generation capacity, fuel type, year constructed, utility name, and information

[6] The threshold was $50bn in total assets when data collection began and increased to $100bn in 2019.

[7] The Y-14Q uses the 2012 NAICS codes to categorize loans. Fossil fuel electric power generation includes both coal and natural gas generation, both of which have the NAICS code 221112 and are undifferentiated in the Y-14Q data.

Figure 1: Electric generation loan volume by category



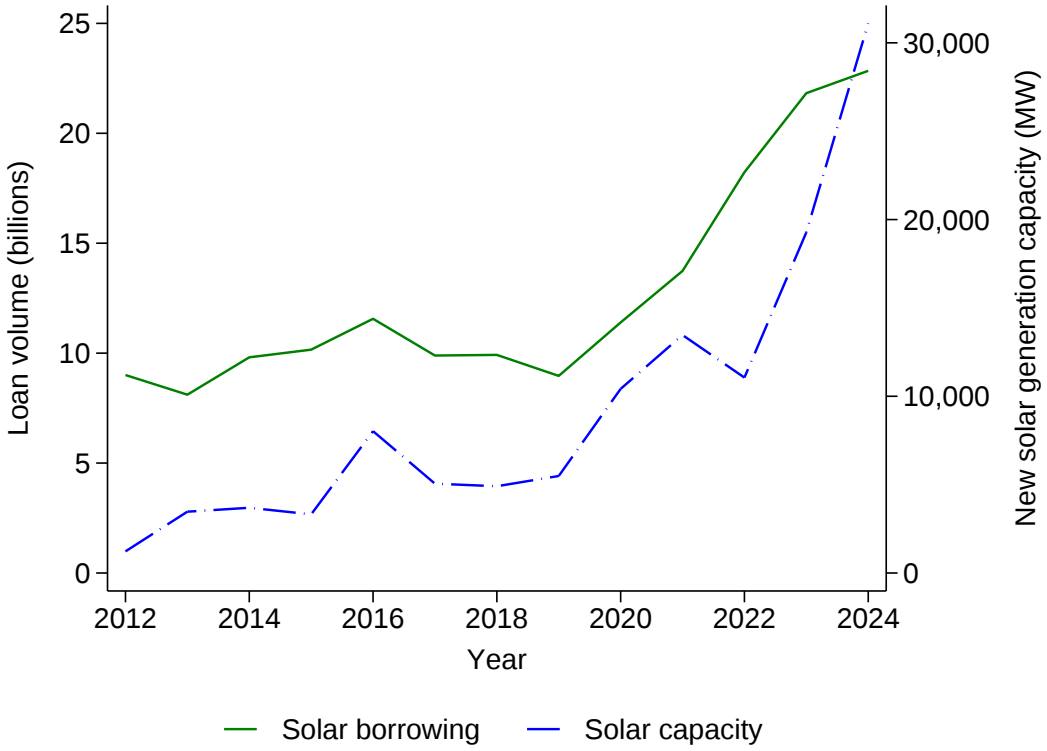
Note: This figure shows total loan volume for the main electric power generation categories. Fossil fuel electric power generation includes both coal and natural gas generation (NAICS 221112). Data omitted for points with less than 20 loan observations. Dollars are nominal.
Source: Y-14Q.

about environmental controls such as scrubbers.

3 Evidence from MATS

This section analyzes firms' responses to plausibly exogenous changes in environmental regulation that raised the cost of operating coal power plants. We begin by describing the policy setting in Section 3.1. In Section 3.2, we show that firms responded to these higher costs by cutting back not only on coal generation capacity, but also on solar generation capacity. In Section 3.3, we provide evidence that these spillovers are the result of

Figure 2: Solar loan volume and annual solar capacity additions



Note: This figure shows solar total loan volume (green, left axis) and annual solar capacity additions (blue, right axis). Dollars are nominal.
Source: Y-14Q and EIA Form 860.

the policy tightening exposed firms' financial constraints, highlighting the importance of financial frictions in understanding the direct and indirect effects of costly environmental regulations on generation activity.

3.1 Background

In 2012, the Environmental Protection Agency (EPA) first proposed the Mercury and Air Toxics Standards (MATS) to limit airborne emissions of mercury and other hazardous air pollutants created by coal power plants. To comply with MATS, all active coal-fired power plants were required to have or install "scrubbers," which clean the emissions from the power plant before they are released by exposing the polluted coal exhaust gasses to a

liquid filtering agent. From 2012 to 2015, there was significant uncertainty as to whether MATS would ever be enforced: the Supreme Court had vacated a previous air quality regulation (the Clean Air Mercury Rule) in 2008, and legal cases were immediately filed against MATS by a number of states' attorneys general. Gowrisankaran, Langer, and Reguant (2024) estimate that the perceived enforcement probability fell as low as 43% in early 2015. In June 2015, the Supreme Court ruling *Michigan v EPA* did not overturn the MATS rule, effectively allowing it to take effect.

The penalties for noncompliance for MATS were large enough that all plants complied with the regulation by the April 2016. Table 1 reports how this compliance was achieved. In 2014, there was around 326,000 MW of active coal generation, with around 54% of that capacity already meeting the standards set forth in MATS (U.S. Energy Information Administration, 2016a). For coal-fired power plants that did not have scrubbers, the only options for achieving compliance by April 2016 were to either (i) retire the plant, (ii) convert the plant to burn natural gas, or (iii) install scrubbers. All three of these options incurred substantial costs.[8]

Table 1 shows that about 81% of coal capacity achieved compliance by installing scrubbers.[9] Rather than paying the substantial costs of installing and operating scrubbers, around 13% of the coal capacity in operation at the end of 2014 retired by April 2016 to comply with MATS. Only 6% converted to burn natural gas.

[8]For a typical 1,000 MW coal-fired power plant, retirement would cost around $117 million (Raimi, 2017), while the cost of converting a coal plant to a natural gas plant depends on what type of conversion (replacing coal with natural gas as heat source or installing a combined cycle plant) and the plant characteristics. Installing an activated carbon injection scrubber system was estimated to cost between $10 million and $30 million in 2007 dollars, while running and maintaining this system for a typical power plant would cost an additional $12–$28 million annually (U.S. Environmental Protection Agency, 2011; U.S. EIA, 2017)

[9]Scrubbers were installed at around the same rate for both regulated and deregulated coal fired power plants. Appendix B.2 provides a discussion of the role of regulation in scrubbers and MATS compliance.

Table 1: How coal plants respond to MATS

Action	Capacity (MW)
Already in compliance (MW)	175,377
Install scrubber (MW)	121,231
Converted to natural gas (MW)	9,526
Retired (MW)	19,698
Total coal (MW)	325,832

Note: The table shows how coal plants active in 2014 responded by the 2016 MATS compliance deadline.
Source: EIA Form 860.

3.2 Effect of MATS on generation capacity

Having established that MATS acted as an unanticipated cost shock for firms with unscrubbed coal plants, we next show that it led to declines in both coal and solar generation capacity[10] for treated firms relative to untreated ones, and that financial frictions played a key role in generating these spillovers.

Our empirical strategy uses the EIA 860 data on energy generation capacity and compares otherwise-similar firms (defined by their utility identifier) that differed only in terms of their unscrubbed coal generation capacity (and thus their exposure to MATS) prior to the Supreme Court decision in 2015 Q3. We restrict the sample to firms that had both fossil fuel (coal and natural gas) and solar generation assets at any point between 2010 and 2024. Our identifying assumption is that the construction of electricity generation capacity for treated and untreated firms were on similar trajectories prior to the implementation of MATS and would have remained so in the absence of the regulation. Specifically, we estimate the following regression:

$$Y_{it} = \beta[\text{Treated X Post}]_{it} + \zeta_i + \delta_t + \epsilon_{it} \tag{1}$$

[10] As mentioned previously, we focus on solar generation capacity, because it has been the single largest source of new generation capacity over the past several years and is expected to account for the majority of new capacity investments over the next decade.

where Y_{it} is the energy generation capacity owned by firm i in year t, ζ_i are firm fixed effects, δ_t are time fixed effects, and ϵ_{it} is the error term. β is our coefficient of interest, which captures the effect of MATS exposure. We define a firm as "treated" if it had at least 250 MW of unscrubbed coal generation capacity at the time the Supreme Court decision was made in 2015Q3.[11] We cluster the standard errors at the firm level and weight observations by the firms' highest total annual generation capacity observed during our sample window.

Table 2: Changes in generation capacity for MATS affected firms

	Coal (MW)	Solar (MW)	Natural Gas (MW)
	(1)	(2)	(3)
Treatment × Post	-807.366***	-371.387*	-15.501
	(225.896)	(188.107)	(429.589)
Firm count	119	119	119
Treated firm count	36	26	35
Observations	897	897	897
R-squared	0.97	0.68	0.99

Note: This table shows the effects of MATS on total generation capacity by generation type between 2015 and 2020. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: EIA Form 860.

Table 2 presents the results of equation 1. Column (1) shows that in the years following the regulation, firms exposed to MATS reduced their coal capacity by more than 800MW. This effect is both statistically and economically significant, as it represents more than 25% of exposed firms' unscrubbed coal capacity in the pre-MATS period. These magnitudes are consistent with the reductions in coal capacity from a combination of retirements and conversions documented in Table 1, and indicate that such reductions were likely driven by MATS exposure.

It is not surprising that a policy raising the cost of operating coal power plants reduced coal generation capacity. What is less obvious is how this policy should affect firms' in-

[11] We use a threshold in levels instead of percent of generation because the cost of the policy depends on the total unscrubbed MW of coal, not its share of the firm's generation fleet. A 250 MW threshold is large enough to capture meaningful costs to the firm to retrofit, but not so large as to miss smaller plants (or boilers) that were affected by the policy. Tables A1 and A2 use smaller and larger thresholds, and find similar results.

vestments in *other* types of generation capacity. This response is determined by two opposing effects. First, by increasing the relative cost of coal generation, we would expect MATS to tilt the composition of firms' generation capacity toward non-coal sources, all else equal. However, as we showed in the previous section, MATS also tied up firms' financial resources by requiring some combination of costly retirements and the installation of new scrubbers while reducing revenues. Given the importance of external financing for investments in new capacity, these costs could instead push them to *reduce* their investments in non-coal capacity.

We find that the latter effect dominates. Column (2) shows large negative effects on firms' solar generation capacity. Solar capacity for treated firms grew roughly 400MW less than untreated firms over the 5 years after MATS. This relative reduction in solar capacity is driven by stronger increases in solar construction for firms without MATS exposure. Column (3) shows that MATS did not cause a change in natural gas generation capacity for the firms in our sample.

Next, we explore the timing of the responses of firms' generation capacity to MATS. To the extent that firms responded by shutting down coal plants, these decisions should be reflected in an immediate reduction of coal generation capacity. On the other hand, investments in new generation capacity can take years to become operational, and we would therefore expect any effects on new solar investments to occur more gradually. To test these predictions formally, we estimate the following event study specification:

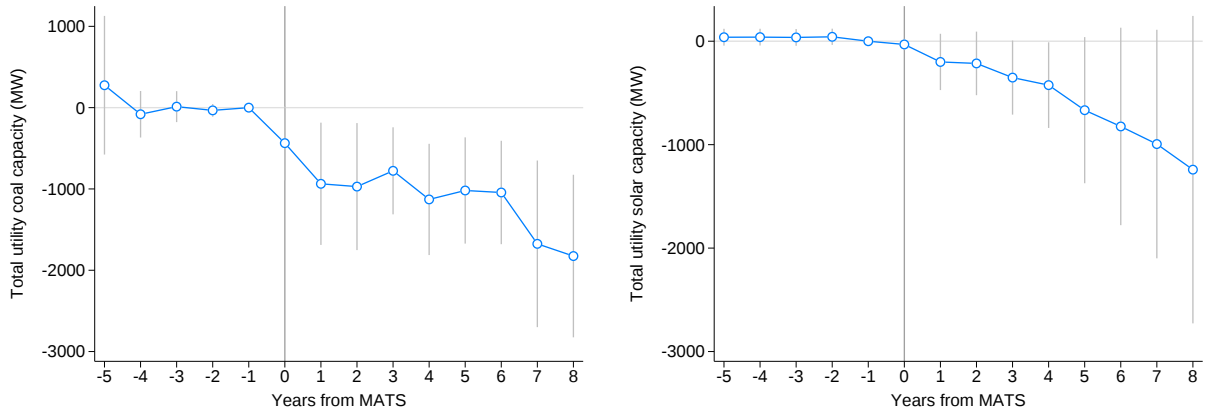
$$G_{it} = \sum_{k=-5, k\neq -1}^{8} \beta_k \cdot (\text{Treated}_i \times \mathbf{1}[\text{Years from MATS}]_{it} = k\}) + \zeta_i + \delta_t + \epsilon_{it} \qquad (2)$$

The results are shown below in Figure 3. The left panel shows that coal capacity declined sharply within a year of the Supreme Court decision that upheld MATS in 2015. This suggests that firms' decisions to retire coal plants were both quickly implemented and permanent.[12] The right panel shows that the relative decline in solar capacity among

[12]We define retirement as no longer showing up as an active power plant in the EIA 860 data. Fully

MATS-affected firms was more gradual, consistent with the treatment group building relatively less solar than the control group over time. As these investments gradually came online over the following years, the gap in solar capacity between treated and control firms steadily widened.

Figure 3: Change in coal capacity for MATS-affected utilities



Note: This figure shows the event study estimate from equation 2. The left and right panels show the cumulative effect of MATS on coal and solar generation capacity, respectively. Error bars show 95% confidence intervals with standard errors clustered at the firm level.
Source: EIA Form 860.

Financial frictions provide a natural explanation for why exposed firms fell behind their peers in solar investments even though MATS only targeted coal generation. By cutting cash flows while simultaneously requiring firms to pay for plant retirements or scrubbers, MATS weakened balance sheets, which could impact the cost and availability of external financing for both fossil and non-fossil investments. In the next section, we use loan-level data to directly test these predictions.

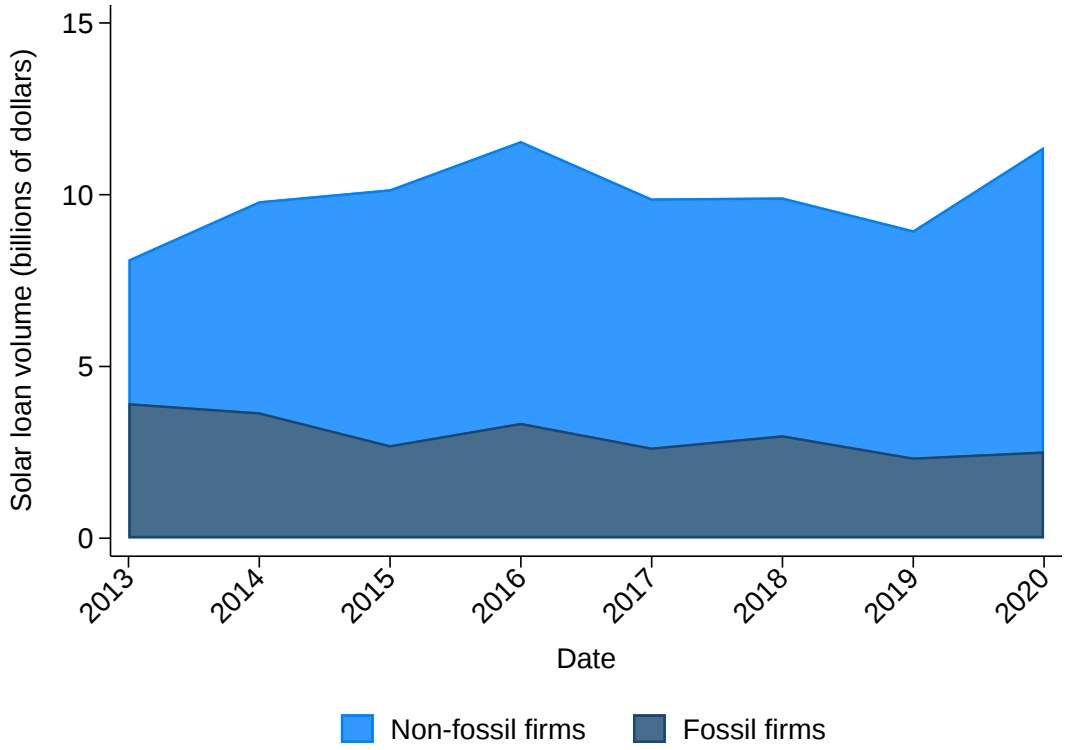
3.3 Effect of MATS on financial outcomes

Here we show that financial spillovers can rationalize the effects of MATS on generation capacity documented in the previous section: While MATS exposure did not have any

decommissioning can take much longer.

negative effects on the volume or terms of lending for exposed firms' fossil operations, it led to reductions in credit supply and higher interest rates for these same firms' solar operations. Figure 4 shows that the share of solar lending flowing to firms that also had fossil fuel generation loans in our data is nontrivial; in 2013 and 2014, around 40% of loan volume went to firms that also had fossil fuel loans, suggesting that internal capital market spillovers driven by shocks to fossil generation capacity could have an economically significant impact on total solar investment.

Figure 4: Solar Loans to Fossil and Non-Fossil Firms



Note: This figure shows the share of solar loan volume borrowed by firms that also borrow for fossil fuel electric generation. Dollars are nominal. Source: Y-14Q.

We use the same empirical strategy as the previous section, which compares firms that had unscrubbed coal generation capacity to otherwise-similar, but unaffected, firms. We use loan-level Y-14Q data, which contain detailed information about loan and borrower characteristics. While the Y-14Q data include loans to many power plants, these loans

cannot easily be associated with each plant's ultimate owner. To determine which firms were MATS-treated, we manually matched the Y-14Q data to the EIA 860 data using the firm name listed in both data sets.[13] Our set of manually-matched firms accounts for 73% of total lending volume for fossil fuel generation capacity in the Y-14Q, and an identical 73% of the total fossil generation capacity in the EIA 860 data.[14] The high match rate suggests that the matched data account for a representative picture of fossil fuel generation financing. Appendix B.1 provides details on the manual matching process. To increase our sample size and power, we also include firms in the Y-14Q with solar and fossil loans that were not matched to the EIA data that we assume are not affected by MATS.[15] Table 3 shows summary statistics for our Y-14Q variables before MATS went into effect.

Table 3: Summary statistics of firms in MATS sample

	Mean	SD	P10	P50	P90
Fossil committed exposure ($mil)	18.96	80.42	0.00	0.00	41.85
Fossil interest rate (%)	0.97	1.31	0.00	0.34	2.69
Fossil maturity (months)	47.95	26.93	17.51	46.15	77.00
Fossil percent of loans asset securitized	34.29	44.46	0.00	0.00	100.00
Fossil probability of default (%)	1.64	6.97	0.11	0.35	2.75
Solar committed exposure ($mil)	11.39	50.56	0.00	0.00	32.76
Solar interest rate (%)	1.73	1.76	0.00	1.59	3.75
Solar maturity (months)	64.59	45.86	11.00	52.79	130.00
Solar percent of loans asset securitized	51.79	47.43	0.00	58.46	100.00
Solar probability of default (%)	1.82	3.93	0.14	0.65	2.79

Note: This table show summary statistics for both fossil and solar borrowing before MATS went into effect (2013-2014). Source: Y-14Q.

Given that the statutory effects of MATS were restricted to coal plants, we begin by analyzing the response of firms' fossil loans. Using the Y-14Q data, we again estimate equation 1, where Y_{it} now denotes financial outcome variables. The first column of Table 4 shows that MATS increased firms' total fossil committed loan volume by 13 percent. While noisy, the point estimate is still positive, suggesting that firms were at least able to avoid meaningful contractions in their fossil borrowing.

[13] Manual matching was employed because there were many differences in firm names used in the Y-14Q and EIA 860 data.

[14] The Y-14Q reports borrower industries using six digit NAICS codes, which combine coal and gas under "fossil generation" (NAICS 221112).

[15] These firms were not matched because their names did not line up with firm names in the EIA 860 data or they did not own coal plants. The results are similar when we drop unmatched firms with fossil loans, which can be seen in table A3.

Next, we consider the effects of MATS on lending terms. Column (2) reports a tiny and statistically insignificant effect on interest rates of roughly one basis point despite a large (though not statistically significant) increase in exposed firms' perceived probability of default shown in Column (3).[16] These seemingly contradictory results can be reconciled by Column (4), which shows that exposed firms increased their reliance on asset-backed lending as defined in Lian and Ma (2021). Past work such as Cerqueiro, Ongena, and Roszbach (2016) and Luck and Santos (2024) has shown that posting more collateral allows firms to obtain better loan terms, and we find evidence consistent with this channel: Following MATS, exposed firms increase their share of asset-backed borrowing by almost 12 percentage points, more than doubling their pre-MATS average rate of 11%.

Finally, Column (5) shows that the average loan maturity increases by about 5 months, representing a roughly 10% increase compared to its pre-MATS average. While the expected effect of a shock that tightens firms' financial constraints on their loan maturity is theoretically ambiguous, our results are consistent with Caglio, Darst, and Kalemli-Özcan (2024), who show in the Y-14Q data that firms tend to borrow at longer maturities when they are smaller, private, or more leveraged, all of which are traditionally associated with being more constrained.

Table 4: Fossil loan outcomes

	Total loan volume (%)	Interest rate (pp)	Probability of default (pp)	Collateralized (pp)	Maturity (months)
	(1)	(2)	(3)	(4)	(5)
Treatment × Post	0.131	-0.014	1.798	11.566***	4.773**
	(0.101)	(0.212)	(2.043)	(3.357)	(2.257)
Firm count	188	128	181	188	185
Observations	987	599	842	987	966
R-squared	0.88	0.77	0.46	0.87	0.80

Note: This table shows the effect of MATS on fossil loan outcomes. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: Y-14Q and EIA Form 860.

These results suggest that firms exposed to MATS were able to avoid major deteriora-

[16] Probability of default is only reliably reported in the Y-14Q data starting in late 2014, limiting the pre-period available for the analysis.

tions in the volume or terms of their fossil lending by increasing their use of collateral.[17] Yet, as shown in section 3.2, the real effects of MATS were not confined to firms' fossil operations. High compliance costs and increased use of collateral for fossil loans should tighten exposed firms' financial constraints and limit their ability to obtain loans for their other lines of business, which could rationalize the large decline in solar investments documented above. Below, we provide empirical evidence consistent with this spillover effect.

Table 5 reports the same outcomes as Table 4 for firms' solar loans. Columns (1) and (2) show statistically and economically significant declines in loan volume of 33% and increases in average interest rates of 88 basis points for exposed firms relative to their untreated counterparts. Column (3) shows no statistically significant change in the probability of default, and the point estimate is negative, suggesting that increasing interest rates are unlikely to be driven by exposed firms simply pursuing riskier solar projects.

Table 5: Solar loan outcomes

	Total loan volume (%)	Interest rate (pp)	Probability of default (pp)	Collateralized (pp)	Maturity (months)
	(1)	(2)	(3)	(4)	(5)
Treatment × Post	-0.326**	0.885***	-2.444	16.966	10.608**
	(0.144)	(0.312)	(1.516)	(16.590)	(5.299)
Firm count	133	133	104	133	133
Observations	570	570	422	570	570
R-squared	0.93	0.66	0.61	0.86	0.86

Note: This table shows the effect of MATS on solar loan outcomes. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: Y-14Q and EIA Form 860.

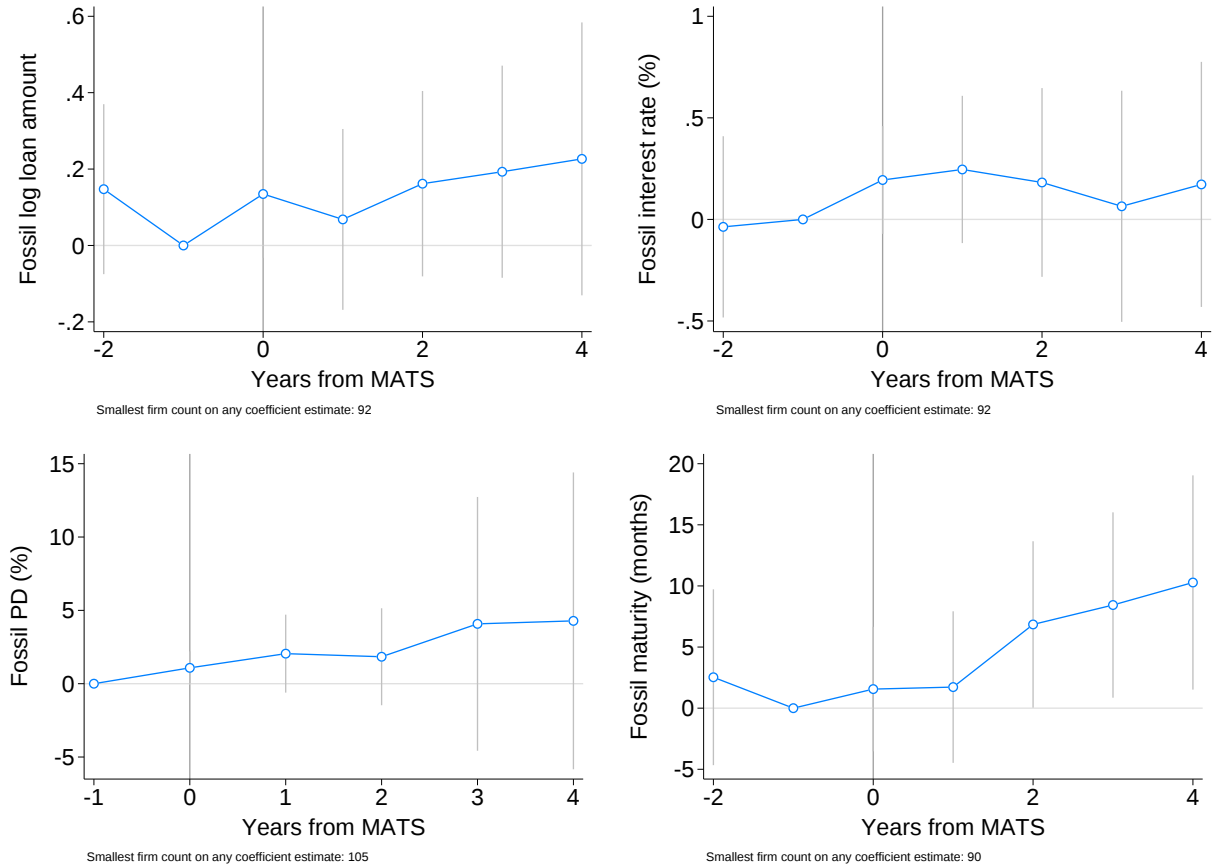
Column (4) reports that this worsening in solar loan terms occurred despite the fact that exposed firms, as with their fossil loans, increased the share of their solar loans that were explicitly collateralized by their assets. The estimate is imprecise, but the positive coefficient suggests that worsening solar terms are not a mechanical consequence of shifting collateral across lines of business. Instead, this result points to a broader deterioration of

[17] Many of the firms in our sample are rate-of-return regulated, and they can pass their costs along to their customers. However, that rate case regulatory process can take years, and in the case of MATS, financing was needed relatively quickly to install and run scrubbers.

the firm's financial prospects that extended beyond fossil operations, even though MATS exclusively targeted coal plants. Consistent with tighter financial constraints, Column (5) reports that the maturity of exposed firms' solar loans increased by more than twice as much as the maturity of their fossil loans, echoing the financial constraint patterns documented in Caglio et al. (2024).

Further evidence for this channel can be seen in the event-study estimates plotted in Figures 5 and 6, which explore the dynamics of these financing effects for fossil and solar loan terms. The figures show that the largest changes to terms of lending for solar loans occurred within the first two years following MATS. This timing aligns with the event-study estimates in Figure 3, where the largest effects on new solar capacity appear precisely during the window one would expect if changes in loan terms today translate into realized capacity with a four-to-six year lag.

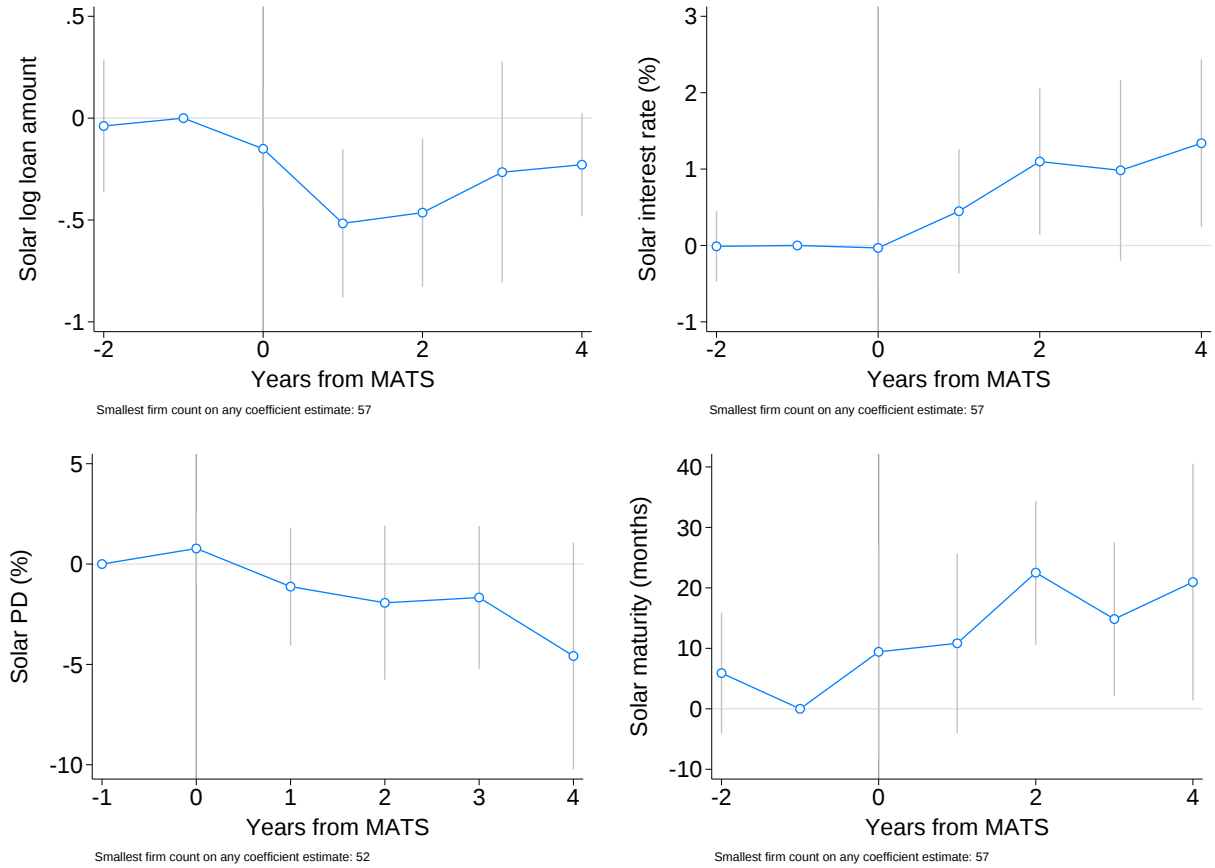
Figure 5: Fossil loans



Note: This figure shows the event study estimate from equation 2, focusing on loan outcomes for fossil loans. The Probability of Default variable (PD, bottom left panel) is only reported in the Y-14Q data after 2014. Error bars show 95% confidence intervals with standard errors clustered at the firm level.
Source: Y-14Q and EIA Form 860.

Taken together, our empirical results show that regulations that raise the cost of fossil generation can spill over to financing and, ultimately, to investment in other kinds of energy production. While the direct compliance costs of MATS were contained to firms' fossil operations, installing scrubbers and shutting down coal plants tied up financial resources that could otherwise have been put to use in other lines of business. As noted in Lamont (1997) and Giroud and Mueller (2015), these effects should be strongest for industries whose investments are subject to greater degrees of financial constraint. Hence, this channel is likely to be particularly relevant for electric power generation, where projects

Figure 6: Solar loans



Note: This figure shows the event study estimate from equation 2, focusing on loan outcomes for solar loans. The Probability of Default variable (PD, bottom left panel) is only reported in the Y-14Q data after 2014. Error bars show 95% confidence intervals with standard errors clustered at the firm level.
Source: Y-14Q and EIA Form 860.

require large up-front investments and can take four to six years from initial planning to completion (U.S. Energy Information Administration, 2016b; Nilson, Hoen, and Rand, 2024).

4 Evidence from IRA

Having shown that financial frictions affected the transmission of a policy that imposed costs on specific types of electric power generation, we next analyze their role in driving the real effects of a policy which instead provided subsidies. For this exercise, we study the Inflation Reduction Act (IRA), which included several tax provisions designed to encourage renewable energy investments. We first provide suggestive evidence that the IRA increased entry for small solar energy producers relative to large producers. We then show that the IRA disproportionately lowered interest rates for these smaller solar electricity producers, who were more likely to be financially constrained. These results suggest that financial frictions play a key role in driving the real effects of subsidies targeting electricity generation.

4.1 Background

The investment tax credit (ITC) and production tax credit (PTC), which provide subsidies for solar and wind development, have been available since 1978 and 1992, respectively. Before the passage of the IRA in 2022, both credits were non-refundable, meaning they could only be claimed by firms with tax liabilities, which small solar and wind developers typically do not have. Before the IRA passed, firms without tax liabilities were forced to use complex financial arrangements called tax equity swaps to take advantage of the ITC or PTC.[18] However, these products were very expensive, resulting in developers without tax liabilities receiving only a portion of the full government subsidies: The nonrefundable PTC was valued at roughly 85 cents on the dollar (Johnston, 2019). Reliance on these costly derivatives meant that larger solar developers with tax liabilities benefited more from the ITC and PTC than smaller firms.

The costs of the non-refundability of the ITC and PTC have been well documented

[18] See section C.1 for a detailed discussion of tax equity swaps.

(Keightley, Marples, and Sherlock, 2019; Johnston, 2019), and in 2022 the IRA addressed them by allowing firms to sell the tax benefits directly to other firms. Public coverage of the provision highlighted how the new transferability rules were changing how solar and wind developers were taking advantage of the tax credits (U.S. Department of the Treasury, 2024; Rubin and Ramkumar, 2024; Weaver, 2024). While the transferability of tax credits technically applied to all firms, in practice, it effectively eased financial constraints for smaller firms[19] relative to larger firms with tax liabilities. Hence, our empirical strategy examines the effects of the transferability of the ITC and PTC by comparing loan outcomes for small firms to large firms before and after the IRA passed.

4.2 Effects of the IRA on generation capacity

We begin by providing some suggestive evidence that the IRA resulted in more small firms entering the market to build solar capacity using data from EIA form 860. We define a firm as "small" if their highest total generation capacity between 2016 and 2024 was less than 400 MW.[20] Although this cutoff classifies roughly 95% of firms as small, we choose it because it is unlikely that firms that have built less than 400 MW of capacity over our sample would have sufficient tax liabilities to take advantage of the refundable ITC/PTC tax credit. The cutoff also results in similar pre-IRA capacity additions for firms above and below the threshold, making for an easier visual comparison. The left panel of Figure 7 below compares new solar generation capacity built by these small firms to their larger counterparts in each year before and after the IRA.

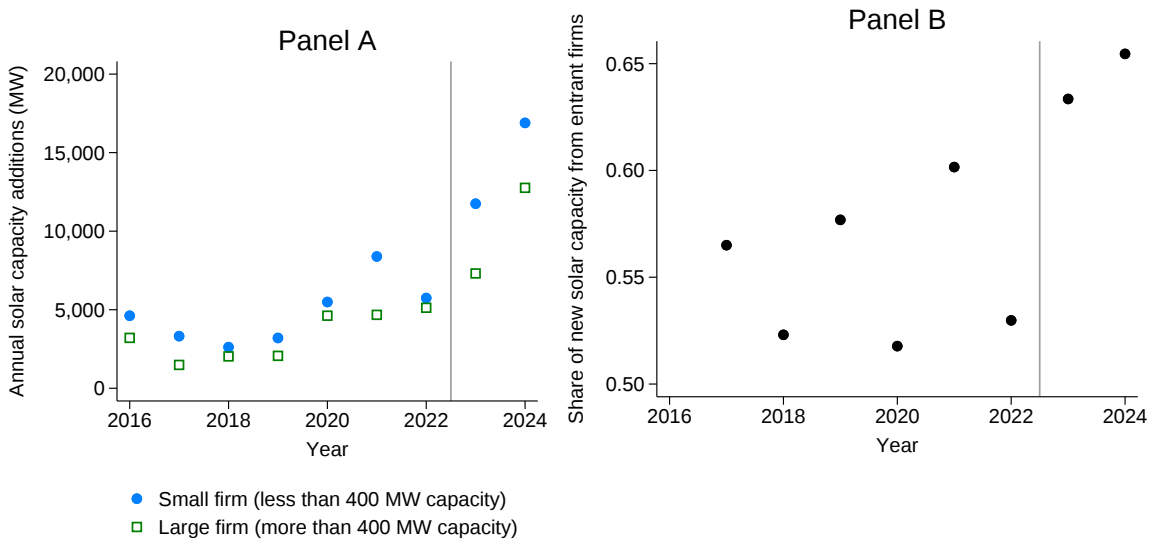
Prior to the IRA passing in 2022, large firms and small firms accounted for a similar total quantity of capacity additions each year. After the IRA was passed in 2022, however, smaller firms accounted for a notably larger share of new capacity additions.[21] The

[19] Including those utilizing the project finance model discussed in Section 2.1. See Aldy (2025) and Bistline and Wolfram (2025) for a detailed discussion of the IRA and its components.

[20] We define a firm by its utility identifier and exclude firms with less than 5 MW of generation, though this has no effect on the analysis in Figure 7.

[21] Appendix Figure A1 extends the analysis through 2025 using planned construction, and finds a similar

Figure 7: New solar capacity added by firm size



Note: Panel A shows new solar capacity by year based on maximum firm size (in MW) over the sample. Panel B shows the share of new solar capacity that is being built by new entrants (firms that did not exist in the previous period).
Source: EIA Form 860.

right panel shows a similar jump in the share of new solar capacity coming from new entrants—who overwhelmingly tend to be small producers—following the IRA's passage. While these results are not causal, they are consistent with the idea that the transferability of the ITC and PTC in IRA benefited smaller solar energy developers relatively more than larger ones. In the next section, we provide evidence suggesting these effects were a direct consequence of the fact that the IRA disproportionately eased financial constraints for smaller firms.

4.3 Effects of the IRA on bank lending

Given the Inflation Reduction Act's emphasis on easing financial constraints for smaller producers, our empirical strategy compares the effects of the IRA on financing conditions for small firms' solar energy projects relative to large firms'. The much larger pool of firm

result.

names for solar energy loans relative to fossil loans in the Y-14 renders the manual matching process used in Section 3.2 infeasible. Instead, for this exercise, we define treated "small" firms as those with less than $30 million of electricity generation loans in the Y-14 prior to the IRA, though our results are robust to a wide range of alternative thresholds.[22] We estimate the following equation:

$$Y_{it} = \beta[\text{Small firm X Post}]_{it} + \zeta_i + \delta_t + \epsilon_{it} \tag{3}$$

Where Y_{it} is a bank finance outcome for firm i in year t, ζ_i is a firm fixed effect, δ_t is a time fixed effect, and ϵ_{it} is an error term, which we cluster at the firm level. Post is an indicator for the passage of the IRA, which turns to 1 for all firms starting 2023. Our coefficient of interest is β, which captures the effect of the IRA on smaller firms solar borrowing behavior relative to larger firms. Our identification assumption is that the financing terms for solar energy projects were on similar trajectories for all firms prior to the IRA's unanticipated[23] passing, and that these similar trends would have continued in its absence. We only include firms that had solar loans in the year before the IRA passed to focus on the subset of firms best positioned to expand their solar capacity.

Table 6 shows the pre-period values of our outcomes of interest for smaller treated firms and larger control firms; summary statistics for the pooled sample are reported in Appendix Table A5. Treated firms have smaller loans, higher interest rates, and longer maturities than the larger control firms. These differences are consistent with larger firms being able to secure better interest rates and the findings in Caglio et al. (2024) that loans to firms generally considered to be less financially constrained tend to have slightly shorter maturities in the Y-14 data.

[22] Electricity generation loans include loans to fossil fuel, wind, solar, nuclear, and hydro power.

[23] After extensive discussions throughout 2021 and early 2022, Congressional discussions led to an unexpected majority for the bill in late July 2022 https://www.politico.com/news/2022/07/27/manchin-schumer-senate-deal-energy-taxes-00048325, and the IRA quickly passed in August. The long deliberations and sudden bill approval suggest that the IRA was not anticipated by energy companies.

Table 6: Comparison of treated and control IRA firms in pre period

	IRA treated (small firms)	IRA control (large firms)	P-value of diff
Solar committed exposure ($mil)	11.06	75.04	0.000
Solar interest rate (%)	3.10	2.41	0.000
Solar maturity (months)	69.07	56.22	0.000
Solar percent of loans asset securitized	56.04	43.39	0.000
Solar probability of default (%)	4.10	2.96	0.014

Note: This table compares the treated and control group before the IRA went into effect (2019-2021).
Source: Y-14Q and EIA Form 860.

Table 7 reports results of estimating equation 3. While Column (1) shows that the IRA's effects on loan volume were similar for all firms following the IRA, Column (2) shows that solar loans to smaller firms became much cheaper. The 61 basis point decline in the average interest rate on solar loans for small firms relative to large ones is statistically significant and economically large, representing almost the entire pre-period gap between IRA treated and control firms shown in Table 6. Figure 8 uses an event study to show the timing of the interest rate decline, which primarily happened in the year after the IRA passed.

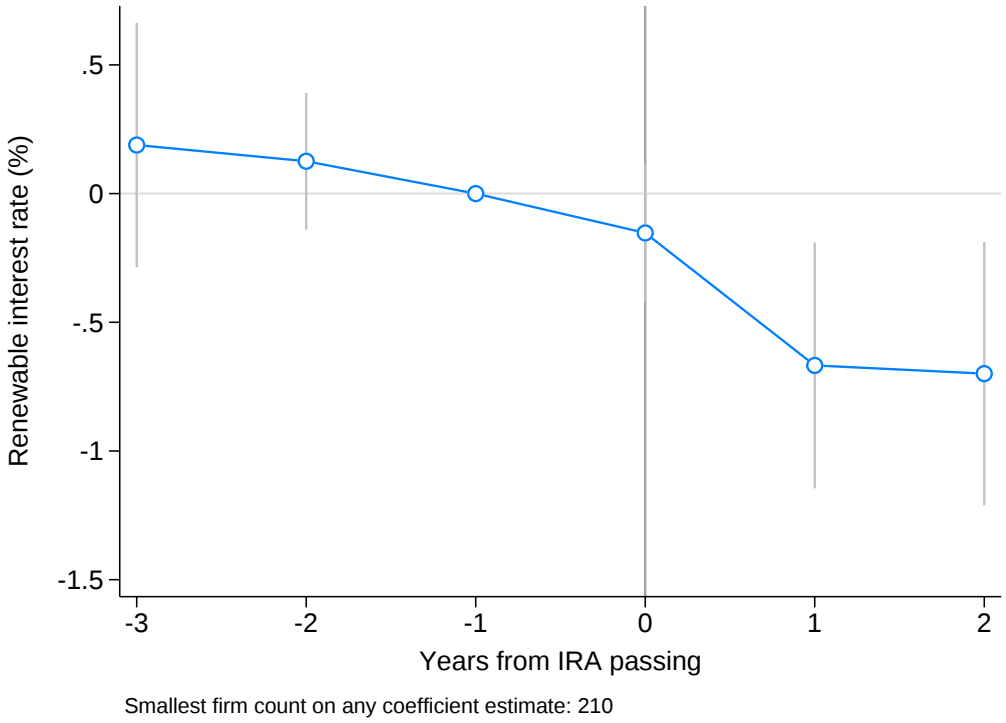
Table 7: Renewables loan outcomes

	Total loan volume (%)	Interest rate (pp)	Maturity (months)
	(1)	(2)	(3)
Treatment × Post	0.054	-0.610***	-5.595***
	(0.065)	(0.183)	(2.047)
Firm count	470	418	466
Treated firm count	216	176	212
Observations	2231	1885	2216
R-squared	0.90	0.85	0.91

Note: This table shows the effect of IRA on renewables loan outcomes. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: Y-14Q and EIA Form 860.

How did the IRA reduce borrowing costs for small projects relative to large ones? One natural explanation is that, by removing the need for a tax equity swap and giving firms more cash up front, the IRA allowed firms to fund the same project with lower leverage. Contributing more money to a project up front gives firms more "skin in the game," which mitigates the adverse consequences of asymmetric information for banks and expands the

Figure 8: The effect of the IRA on the renewables interest rate for small firms



Note: This figure shows the event study estimate from equation 2, applied to the IRA treatment. Error bars show 95% confidence intervals with standard errors clustered at the firm level.
Source: Y-14Q and EIA Form 860.

set of firms' potential investments.

Another non-mutually exclusive possibility is that the IRA induced a shift in the composition of firms' loans: Column (3) shows a statistically significant decline of about 6 months in the average solar loan maturity, representing roughly 10% of the pre-IRA average. Given that shorter-maturity loans tend to have lower interest rates, one possible explanation for the cheaper borrowing costs for small firms following the IRA is that these firms took advantage of their improved financial position to borrow at shorter maturities with lower term premia.

Because this analysis includes only firms that had solar loans prior to the IRA passing, it necessarily omits new entrants, who tend to be smaller and more financially con-

strained. Thus, we view these effects as a lower bound on the true magnitude of the degree to which the IRA eased small firms' financial constraints, and it is likely that the new entrants captured in the right panel of Figure 7 experienced larger declines in borrowing costs than our results here would imply.

Overall, these results provide further support for the presence of a "financial accelerator" mechanism for energy investments, in which a subsidy's real effects are largest for the set of firms that experience a relaxation in their financial constraints.

5 Conclusion

Demand for electric power is projected to soar in coming years, and questions about what kinds of new generation capacity will be built to meet this demand and who will build it are likely to remain top of mind for policy makers and regulators. These investments will require massive upfront costs and take years to produce revenues, making them highly dependent on access to external financing. In this paper, we show that these financial constraints play a key role in driving the ultimate effects of taxes and subsidies targeting the electricity sector. This channel can simultaneously explain why raising the costs of fossil generation caused by MATS reduced solar energy investments, and why changes to renewable energy tax credits in the IRA disproportionately benefited smaller and newer firms.

Our results highlight both challenges and opportunities for policy makers seeking to influence how the growing demand for power will be met. On one hand, the fact that targeted regulations can generate unintended spillovers to other kinds of generation activity through firms' internal capital markets suggests the need for a more comprehensive understanding of firms' entire generation portfolios when evaluating potential regulatory consequences. At the same time, the finding that relatively modest declines in financing costs led to meaningful swings in the composition of investment suggests that financial

market interventions can be highly effective in subsidizing new generation capacity.

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Appendix

A Appendix tables and figures

Table A1: Changes in capacity after MATS with 150 MW treatment cutoff

	Coal (MW)	Solar (MW)	Natural Gas (MW)	Total (MW)
	(1)	(2)	(3)	(4)
post=1 × treatment_150	-823.519***	-417.572**	-49.477	-695.903**
	(215.908)	(200.261)	(461.296)	(348.298)
Firm count	119	119	119	119
Treated firm count	40	29	39	40
Observations	897	897	897	897
R-squared	0.97	0.69	0.99	0.99

Note: Regression estimates from equation 1. This table uses 150 MW as the cutoff for treatment. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: EIA Form 860.

Table A2: Changes in capacity after MATS with 500MW treatment cutoff

	Coal (MW)	Solar (MW)	Natural Gas (MW)	Total (MW)
	(1)	(2)	(3)	(4)
post=1 × treatment_500	-818.332***	-350.666*	37.153	-628.875*
	(230.408)	(181.475)	(417.977)	(343.518)
Firm count	119	119	119	119
Treated firm count	31	21	30	31
Observations	897	897	897	897
R-squared	0.97	0.68	0.99	0.99

Note: Regression estimates from equation 1. This table uses 500 MW as the cutoff for treatment. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: EIA Form 860.

Table A3: Fossil loan outcomes excluding unmatched fossil

	Total loan volume (%)	Interest rate (pp)	Probability of default (pp)	Collateralized (pp)	Maturity (months)
	(1)	(2)	(3)	(4)	(5)
Treatment × Post	0.206	-0.096	1.740	9.400**	6.148**
	(0.132)	(0.314)	(1.986)	(4.363)	(3.019)
Firm count	69	46	68	69	69
Observations	420	247	351	420	419
R-squared	0.87	0.77	0.43	0.87	0.86

Note: Regression estimates from equation 1, focusing on fossil loans. This table is similar to table 4, but all the unmatched fossil firms are dropped from the estimation sample. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: Y-14Q and EIA Form 860.

Table A4: Solar loan outcomes without unmatched fossil

	Total loan volume (%)	Interest rate (pp)	Probability of default (pp)	Collateralized (pp)	Maturity (months)
	(1)	(2)	(3)	(4)	(5)
Treatment × Post	-0.294**	0.981***	-1.717	15.490	10.127*
	(0.145)	(0.317)	(1.338)	(16.587)	(5.399)
Firm count	115	115	95	115	115
Observations	510	510	388	510	510
R-squared	0.93	0.66	0.47	0.86	0.85

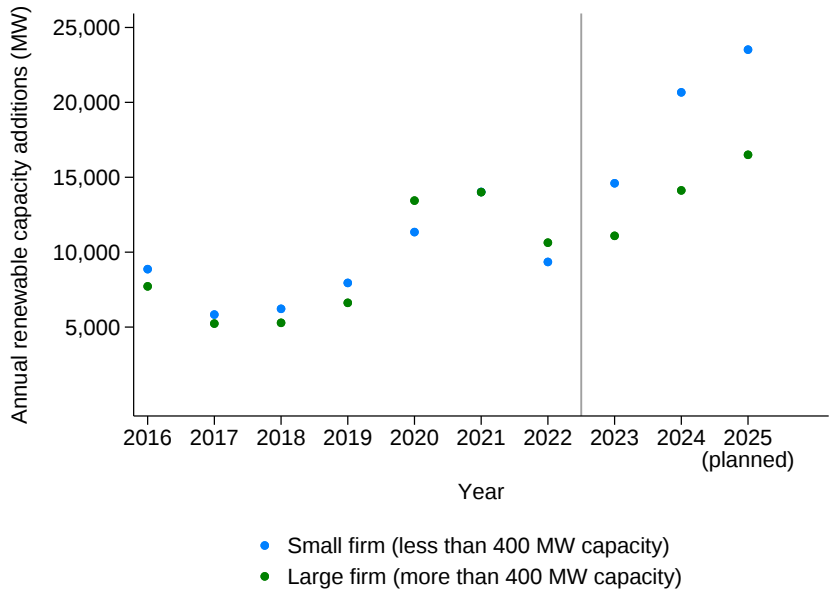
Note: Regression estimates from equation 1, focusing on solar loans. This table is similar to table 4, but all the unmatched fossil firms are dropped from the estimation sample. Standard errors clustered at the firm level. Signif. codes: ***: 0.01, **: 0.05, *: 0.1.
Source: Y-14Q and EIA Form 860.

Table A5: Summary statistics of firms in IRA sample

	Mean	SD	P10	P50	P90
Renewable committed exposure ($mil)	44.52	81.36	2.38	22.00	113.61
Renewable interest rate (%)	2.73	1.72	0.00	2.52	5.00
Renewable maturity (months)	62.43	49.26	10.00	54.00	124.09
Renewable percent of loans asset securitized	49.52	47.17	0.00	50.00	100.00
Renewable probability of default (%)	3.49	14.66	0.14	0.55	2.74

Note: This table shows summary statistics before the IRA went into effect (2019-2021).
Source: Y-14Q.

Figure A1: New renewables capacity added by firm size



Note: This figure shows new capacity by year based on maximum firm size (in MW) over the sample. It is the same as figure 7 but it also includes planned 2025 capacity.
Source: EIA Form 860.

B Data definitions and sample construction

B.1 Cleaning and matching of Y-14Q to EIA data

This section describes the cleaning of the Y-14Q data and matching to the EIA-860 data. First, we limit the Y-14Q to NAICS codes related to electric power generation (NAICS 221111-221118). Next, we clean the Y-14Q data. The Y-14Q data provides information on the name of the entity taking out the loan and the tax identification number (TIN). The Y-14Q is loan-level data, and the same name and TIN are not always used across every loan from the same firm. Occasionally, either the name or the TIN is missing from an observation. In cases where either the name or the TIN is missing, we create a new identifier grouping firms that have either the same TIN or name.

Matching is done using the firm name from the Y-14Q and the utility name in the EIA 860 data. We focus on firms that had loans for fossil fuel electricity power generation (NAICS 221112) in the year before treatment (2014 Q2 to 2015 Q2). Matching was prioritized for firms that had larger fossil fuel electric power generation Y-14Q bank loan exposure.

One complication is that data is reported in the EIA 860 data at the utility level, which may not match the firm definition in the Y-14Q data.[24] In many cases, parent companies will own multiple utilities that are reported as separate entities in the EIA 860 data. For example in 2014, American Electric Power owned many utilities including Appalachian Power, Indiana Michigan Power, Kentucky Power, the public service company of Oklahoma, and Southwestern Electric power. All of these utilities are reported in the EIA 860 data under their utility names, not as American Electric power. However, bank loans may have been obtained by any of the utilities, or its parent company, American Electric power, to fund operations. The parent company structure makes it complicated to match the Y-14Q bank loan data to their associated generation portfolios.

[24] A utility can be as large as The Tennessee Valley Authority (16 GW of coal generation) or as small as Panther creek power operating LLC (94 MW of coal generation).

To deal with the complicated firm structure, manual review was used to appropriately aggregate utilities and bank loans to the correct parent company. There is no official database linking these firms, so the authors' judgement was used to best aggregate to the firm level.

The matching process resulted in a large share of coal generation in the EIA 860 being matched to loans in the Y14. Table A6 shows that 73% of the MW of coal recorded by the EIA 860 in 2014 was matched to data in the Y14. The match rate is lower for non-fossil NAICS codes because we prioritized coal generation in the match process.

Table A7 shows that 73% of the total fossil loan volume in the Y-14Q in 2014 was matched to generation data in the EIA 860. Prioritizing coal generation in the match process means that the solar and wind match rates were much lower. However, since the empirical strategy determines treatment status using a firm's coal generation portfolio, a low match rate for non-fossil loans has a limited effect on the results.

Table A6: Share of EIA MW matched to Y-14Q data

Category	Share
Share coal MW matched to Y14	0.73
Share fossil MW matched to Y14	0.61
Share total MW matched to Y14	0.54
Share renewable MW matched to Y14	0.22

Note: This table shows the share of generation (in MW) matched between the EIA 860 2014 data and the 2014 Y14.
Source: Y-14Q and EIA Form 860.

B.2 Regulation and MATS

Table A8 provides statistics on coal fired power plants and compliance with MATS by regulatory status. Deregulated coal plants were more likely to have scrubbers in 2014 than regulated coal plants. This may seem counter intuitive based on the Averich Johnson affect outlined in Fowlie (2010), but by 2014, a lot of deregulated coal capacity had retired

Table A7: Share of Y-14Q Loan volume EIA MW matched to Y-14Q data

Category	Total loan volume (Billions)	Loan volume share matched
Fossil loans	52.1	.73
Solar loans	40.8	.28
Wind loans	8.8	.27

Note: Table shows the share of loan volume (in 2014) by category matched between the EIA 860 2014 data and the Y14.
Source: Y-14Q and EIA Form 860.

(Davis and Weber, 2025). Of the remaining deregulated coal, plants with scrubbers were less likely to retire than plants without scrubbers.

Table A8: How coal plants respond to MATS by regulatory status

Action	Deregulated	Restructured
Already in compliance (MW)	67,324	108,054
Install scrubber (MW)	15,306	105,925
Converted to natural gas (MW)	2,128	7,398
Retired (MW)	1,494	18,204
Total coal (MW)	86,251	239,581

Note: The table shows how coal plants active in 2014 responded by the 2016 MATS compliance deadline, broken down by regulatory status.
Source: EIA Form 860.

For the plants that were not in compliance with MATS, regulated and deregulated plants responded in similar ways. Around 81% of both regulated and deregulated plants installed scrubbers to comply with MATS. Of the plants that did not installs scrubbers, deregulated plants were a bit more likely to convert to natural gas, while regulated plants were more likely to retire.

C Additional background

C.1 Tax equity swaps

Before the IRA introduced transferable tax credits, smaller solar and wind developers would not have the tax liabilities to directly take advantage of the ITC or the PTC. To use the ITC or PTC, small developers would use tax equity swaps, where an external partner would contribute money to the project in exchange for both a portion of the tax credit and a future stream of payments over the life of the project. Payments to the tax equity investor are defined in terms of after-tax flip yields, which can range from 6.5% to 8% (Cohen, Sternthal, Knapp, and McKenna, 2017). The structure of these deals guaranteed the tax equity investor a specific return on their initial investment. For example, in the case of the ITC for a solar project, the tax equity investor would receive a large share of the initial ITC payment, and then receive payments from the revenue generated by the project until their after-tax flip yield has been satisfied. At that point, the structure flips, with the developer retaining most of the revenues from the solar project. Because the structure of these deals is complicated and project-specific, it is difficult to pin down what share of the ITC is lost to a tax equity swap, but it is likely in the 10% range. Either way, the relatively high after-tax flip yields demanded by tax-equity investors shows that while tax equity swaps allow smaller firms or project finance entities to take advantage of the ITC or the PTC, it meaningfully reduces the value of the pre-IRA subsidy compared to a transferable subsidy.

There are also fixed costs associated with implementing a tax equity swap. Weaver (2024) lists that tax equity investments are typically at least $1 or $2 million to offset the at least $75,000 fees associated with creating the tax equity swap. As a result, projects were likely to be larger before the transferability provision of the IRA.

One tax advantage remained for larger firms after the transferability of the ITC and PTC, the ability to take advantage of the Modified Accelerated Cost-Recovery System

(MACRS). MACRS allows an accelerated depreciation schedule for capital investments for a variety of investments (including non-energy projects), which reduces a firms tax liability (Congressional Budget Office, 2025). Small firms without tax liabilities that directly transfer their ITC or PTC benefits still cannot take advantage of MACRS unless they use a tax equity swap. MACRS was unchanged by the IRA, so it does not affect our results in section 4, but it remains an advantage that larger firms have in financing renewable projects.