Financing Investment in Electricity*

PRELIMINARY

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Abstract

Meeting rising global electricity demand requires financing large-scale investments in power generation. While renewable energy plants produce the same electricity output as fossil fuel plants, renewables are financed differently: they typically rely on "project finance" and Power Purchase Agreements (PPAs) that lock in electricity prices and quantities over the long-term. We develop and calibrate a framework that explains these differences by linking production technologies to financing choices under financial frictions. The model shows how PPAs can help mobilize private funds through a *capital structure channel*. Because renewables have near-zero marginal costs, price certainty under PPAs can significantly reduce cash-flow risk, enabling greater use of bank debt relative to costly equity. This lowers discount rates and increases investment in renewables. In contrast, we show that PPAs are much less attractive for fossil fuel projects with volatile input costs. The framework also highlights a downside of PPAs for renewables: the amplification of macroeconomic shocks, leading to higher investment volatility over the business cycle. We use our framework to explain the slowdown of renewable investment following the 2021-2022 inflationary episode and show that state-dependent investment subsidies indexed to cost shocks can help stabilize private investment.

Keywords: energy investment, renewables, project finance, financial frictions, cost of capital, bank lending, macro-economic risk, inflation

JEL codes: E22; G31; Q42; Q43; Q55

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1 Introduction

Global electricity demand is projected to grow dramatically in the coming years. The rapid growth of the data economy, increasing stakeholder pressure to reduce carbon emissions, and the need to diversify energy sources to reduce dependence on foreign suppliers all make investing in electricity generation capacity a priority in many countries. Technologies like solar, wind, and energy storage have become economically competitive and are now being deployed on an increasingly large scale, offering near-zero marginal costs and carbon emissions once installed. However, these technologies are still widely believed to be "harder to finance" than fossil fuel alternatives. Funding gaps and bottlenecks are frequently cited in media and policy circles as challenges that impact renewable deployment.[1] As an example, the largest commercial offshore wind power plant in the United States, Vineyard Offshore Wind Farm, was a colossal investment of $2.5 billion that took a decade to develop before it began operating in 2023. Unlocking financing was particularly challenging, as the CEO put it in 2021: "There have been many milestones passed over the last several months... Achieving financial close is the most important."[2]

An important feature of electricity generation is that renewables and fossil fuels typically rely on different financing structures, even though they produce the same homogeneous good. Fossil fuel plants are usually financed by utilities using on-balance sheet vehicles, like bonds. In contrast, renewable energy projects are typically financed through bank loans using a structure known as "project finance", which differs from traditional corporate financing in two key dimensions. First, lenders nearly always require Power Purchase Agreements (PPAs) as a condition to lend against renewable energy projects. PPAs are long-term contracts where a buyer (usually a utility or large corporate off-taker) agrees to purchase a fixed quantity of electricity generated by the power plant at a pre-negotiated price. For instance, Vineyard

[1] See e.g., "Bridging the Clean Energy Investment Gap" (OECD, 2024); "Reducing the Cost of Capital" (IEA, 2024).

[2] "Vineyard Wind 1 Becomes the First Commercial Scale Offshore Wind Farm in the US to Achieve Financial Close." Link

Wind LLC secured a 20-year PPA with utilities National Grid, Eversource, and Unitil, selling a fixed quantity of electricity to them at a price of \$0.09/kWh. These types of long-term contracts are rarely required by lenders in other settings. Second, project finance requires setting up a separate off-balance sheet special-purpose investment vehicle (SPV), established solely to own and operate the project. Lenders extend credit to the SPV based only on the specific project's risks and expected cash flows. For example, Vineyard Wind LLC was set up as a standalone company that only owns one asset: the Vineyard Wind project.

In the United States the rise of project finance has gone hand in hand with the rapid growth of renewables and the increasing role of independent power producers (IPPs). Renewable projects are now predominantly developed by IPPs, firms that own generation assets but do not distribute electricity directly to consumers and firms. IPPs are smaller, less regulated, and more dependent on bank financing than the regulated utilities that have been historically dominant (Cicala, 2015; Andonov and Rauh, 2022; Gowrisankaran et al., 2024).

This paper develops a simple structural model of IPP investment in electricity to explain the differential use of project finance and PPAs across technologies. The main innovation is to link the properties of different production *technologies* to *finance*. In the presence of financial frictions, these financing choices can matter for investment outcomes, via their effects on expected returns, risk, and discount rates. The model shows quantitatively that the project finance structure generally increases investment in renewables primarily through a *capital structure channel*. Because renewables have near-zero marginal costs, PPAs significantly reduce cash-flow risk. This in turn allows greater use of bank debt relative to equity financing, which lowers discount rates and increases investment. However, this financing channel is technology-specific: project finance is much less attractive for fossil fuel projects with volatile input prices. Importantly, we nevertheless show that there can be a downside to PPAs even for renewables: the amplification of macroeconomic risk such as inflation shocks. This occurs because PPA prices are set in the pre-construction phase, which can fix electricity prices to low levels even when macroeconomic shifts lead to cost increases, eroding the post-construction

NPV of projects. Thus, project finance and PPAs facilitate financing for renewables, but at the cost of introducing greater investment volatility across the business cycle.

An important contribution of our framework is to take an investment perspective to the question of renewables development. Although it is well known that from a production perspective, *resource volatility* in wind and solar inputs (i.e. "intermittency") poses key challenges, from an investment perspective this risk is dominated by *electricity price volatility*. Fluctuations in electricity prices are much less predictable over the project's horizon than a renewable plant's electricity production. By fixing electricity prices with committed buyers, investors in renewable projects can be assured of stable and predictable cash flows. Moreover, the risk profile of fossil fuel technologies is fundamentally different than renewables since they rely on tradable inputs (gas), which adds a second layer of volatility on the cost side. As a result, fixing electricity prices alone does not ensure that cash flows become stable for fossil fuels because input costs remain volatile. To drive this point home, our framework is set up in terms of net present value (NPV), the canonical way to evaluate investment in finance, rather than in terms of a levelized cost of energy (LCOE).[3] While LCOE measures are widely used to compare the cost of different technologies, they abstract from two key features that are central in our theory: (i) the market prices of electricity and fossil fuel inputs are inherently volatile, and (ii) discount rates are endogenous to risk and capital structure. As we will discuss in depth, these two omitted dimensions are in fact critical to understanding the dynamics of renewable investment.

We nevertheless make two comments on the scope of our framework at the outset. First, we model electricity markets in a stylized way, abstracting from much of the complexities of market structure, regulation, and infrastructure that tend to vary across fragmented regional markets (e.g. Cicala (2015), Gowrisankaran et al. (2024)). While these features are important, they are less central for our question which seeks to explain the widespread use of PPAs for

[3]The LCOE (expressed in \$/kWh) is essentially the discounted cost of electricity generation over a power plant's lifetime.

renewables, which is a pervasive feature of IPP investment and bank lending across markets.[4] Our mechanism focuses on electricity price and input cost volatility, which also exists in all electricity markets. Second, we study the value of PPAs for the investing firm and its lenders, abstracting from the details regarding the buyer of electricity that takes the other side of these PPA contracts. We acknowledge that understanding both sides of the PPAs agreement is interesting, especially given the variety of actors involved, from regulated utilities, tech firms, or public entities, having widely different constraints and objectives (Ryan (2021)). That said, this question is beyond the scope of this paper.[5]

The paper proceeds as follows. In the first part of the paper, we present five empirical facts which we use to ground our model. First, renewable energy sources have a much higher share of capital costs relative to operating costs, implying that more financing has to be provided upfront. Second, electricity produced by renewables has a lower supply elasticity than gas plants, which can flexibly change production to meet shifts in demand. Third, natural gas plants face volatile input costs, whereas renewables have limited input costs. While natural gas input costs are correlated with electricity prices, the correlation is not high enough to completely hedge electricity price volatility. Fourth, there is macroeconomic risk in electricity prices. Fluctuations in electricity prices are strongly correlated with aggregate inflation, which affects the investment cost of building new plants. Fifth, we show that PPA prices are closely correlated with current electricity prices, suggesting that shocks to electricity prices are typically perceived as persistent rather than transitory. To establish these five facts, we compile administrative data and engineering estimates from the Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), Federal Energy Regulatory Commission (FERC), and the Lawrence Berkeley National Laboratory (LBNL).

Based on these facts, the second part of the paper introduces a simple structural model of

[4] In some markets regulation essentially prevents the sale of electricity through IPP (Andonov and Rauh, 2022). Our model naturally does not apply to these settings.

[5] From our vantage point, we take as given that in equilibrium, PPA arrangements will consist of electricity buyers that are acceptable counterparties to the bank or investor that requires PPAs as a condition of financing.

project NPVs for different technologies. A simple way to think about the NPV of a potential power plant investment is to distinguish between its *internal rate of return* (IRR) and its *discount rate*, often referred to as its (weighted-average) cost of capital (WACC). The IRR is essentially the expected (annualized) rate of return of the project's future profits relative to initial investment.[6] A project's discount rate is its opportunity cost, i.e. the rate of return on the next best comparable project. An investment has a positive NPV as long as its IRR exceeds its discount rate.[7]

In the third part of the paper, we argue that a PPA can increase the NPV of a renewable project, but not for a fossil fuel project. We make this argument in two steps. In the first step, we show that even a fair and permanent PPA significantly reduces the IRR for a gas project (i.e. lower profitability all else equal), but not for a renewable project.[8] Key to the model is that electricity prices fluctuate stochastically, while PPAs are modeled a long-term commitment to sell the plant's expected output at the average expected market price. In this environment, the use of a PPA affects both expected profits and discount rates, but differently based on the underlying technology. The IRR result follows because a significant share of expected profits for a gas plant comes from flexibility: adjusting output up and down when the market prices of electricity and gas fluctuate. Namely, the option value of adjusting scale ex-post is ex-ante profitable. A PPA undermines that option value by locking in quantity and price ahead of time. This, however, is not the case for renewables because they have low production flexibility: adjusting output to market prices is technologically difficult, if not nearly impossible without storage. Because of that, a PPA does not reduce expected profits through this channel as it does for more flexible gas plants.

In the second step, we argue that the project finance structure significantly reduces the *discount rate* for a renewable project (i.e. reduced financing costs) but not necessarily for a

[6]Mathematically, the IRR of a project's stream of future cash-flow (including initial investment costs) is the discount rate that makes the project's NPV equal to zero.

[7]As long as projected cash-flows satisfy a regularity condition, which typically holds for energy projects.

[8]Of course, any imperfections in PPA contracts (premium, opportunistic renegotiation, counter-party risk, etc.) would further reduce IRR for obvious reasons across all technologies.

gas project. Although most existing work on energy investment takes discount rates as exogenously given, we explicitly model their determination through the lens of classical theories of financial frictions that lead to a *capital structure channel*.[9] Specifically, in the model having more debt (i.e. "leverage") and less equity financing lowers the discount rate. Risk-based debt limits imply that cash-flow risk reduces the debt size offered by bank lenders that manage default risk. Additionally, substituting debt with equity is costly as there is an excess risk-adjusted cost of equity financing.[10] Because renewables have near-zero marginal costs, a PPA that locks-in electricity prices and quantities significantly reduces cash-flow risk, which raises debt limits and reduces expensive equity financing. Keeping these projects off-balance sheet is also helpful to make sure that these very safe cash-flows are not mixed with any other risky investments on firms' balance sheets. In contrast, a PPA is detrimental for a gas project's capital structure, for two reasons. First, a PPA only addresses cash-flow risk coming from market volatility on the output side, but leaves market volatility from input prices unaffected. Second, a PPA reduces expected profits, as discussed above, which tightens debt limits and forces the use of more expensive equity financing.

In the fourth part of the paper, we calibrate the model to show quantitatively how PPAs and the project finance structure specifically fosters more investment in renewables. We discipline the parameters of the model by combining micro-data from different sources: (i) market prices for electricity, (ii) capacity and costs across technologies from LCOE estimates, (iii) financial variables, including the cost of debt and equity, as well as debt limits from banks, to match WACC estimates from NREL.[11] In our main calibration, when a typical gas

[9] A natural question is why we start from the vantage point of frictional financial markets. We argue that frictionless theories of finance like Modigliani-Miller or the CAPM are unlikely to explain PPAs because electricity prices and aggregate stock market factors are not correlated in the data. In practice, Modigliani and Miller's famous irrelevance theorem does not hold and the mix of debt and equity financing impacts the project's discount rate.

[10] In Modigliani Miller, this wedge between risk-adjusted debt and equity cost is zero. We do not explicitly model the sources of this wedge. Frictions that have been studied to rationalize a role for capital structure include taxes, agency costs, inefficient bankruptcy or liquidation. Government guarantees can also lead to subsidized debt financing.

[11] NREL refers to estimates produced by the National Renewable Energy Lab of the Department of Energy based on surveys of developers and generators.

plant adopts a PPA, its IRR falls from 6% to 4.5%, while its discount rate stays close to 5%. This means that a PPA turns this gas investment project from positive to negative NPV. The opposite happens for a typical solar project. A PPA keeps its IRR unchanged around 5.75%. However, with a PPA, the discount rate of the renewables project falls significantly, from 8% to 4.8%, turning the NPV of the investment positive. This is driven by the capital structure channel, as leverage reacts strongly to the presence of a PPA.

Lastly, in the fifth part of the paper, we nevertheless identify a downside of the project finance structure for renewables: the amplification of macroeconomic risk. Although PPAs reduce cash-flow risk post-construction by locking in electricity prices, they shift some of that risk to the pre-construction phase, especially for projects with long development timelines. Unexpected changes in investment costs might turn the NPV negative as construction starts – leading to ex-post abandonment or delay. This mechanism leads to higher investment volatility over the business cycle.

The post-2021 inflation episode was a perfect example: for the first time in recent decades, the cost of building new renewable plants started to *increase* for a number of reasons, including supply chain bottlenecks around the world. Electricity prices also increased significantly at the same time, meaning that without a PPA, rising electricity prices would have mitigated some of these cost increases. However, this channel is shut off with PPAs, since electricity prices are fixed. Furthermore, PPAs are often signed years before construction begins because of the complexity of many renewable projects (offshore wind being the worst case). Because their PPAs locked in low electricity prices, rising costs in the construction phase increased the likelihood that project NPV would be negative ex-post. Offshore wind was hit particularly hard, with roughly $30 billion in investment put on hold or canceled across the United States in spite of generous new subsidies.[12] For this mechanism to exist, our model shows that there must be a *macro* correlation between investment cost shocks and long-lasting electricity

[12]See e.g., "Cancellations Reduce Expected U.S. Capacity of Offshore Wind Facilities" (EIA, 2024), "Wind Industry in Crisis as Problems Mount" (WSJ, 2023), "The Struggles of the Offshore Wind Industry" (FT, 2023).

price shocks, which we verify in the data. The resulting capital crunch and the downside of project finance were perhaps hard to anticipate given the decade-long decline in building costs for renewables, something we provide additional evidence for using data on revisions in investment cost forecasts over time.

In our calibration, fewer projects would have been abandoned or delayed had their PPAs reflected the new, higher electricity prices. This, however, is not an easy solution since that works against the de-risking of cash flows discussed above. The project finance structure therefore creates a trade-off between the microeconomic benefit of reduced cash-flow risk that increases the average scale of investment and the cost of more exposure to macroeconomic shocks over the business cycle. We show that this issue is not limited to cost shocks but also extends to other macro shocks, like interest rate shocks, as long as they are also correlated with electricity prices.

We conclude by studying a potential policy response: state-dependent investment subsidies. In our calibrated model, this policy would reduce volatility in renewable energy investment. Indexing the level of investment tax credits (ITC) to construction costs can maintain projects' NPVs and avoid a dry-up of private sector funding in bad macroeconomic times. While perhaps counterintuitive, a stable policy is thus not always the best way to induce stable investment. There are nevertheless challenges to this type of policy: it requires commitment to a clear rule to avoid policy uncertainty and would likely lead to higher fiscal spending.

1.1 Related literature

This paper is at the intersection of energy, finance, and macroeconomics and contributes to three growing strands of literature. We first relate to a large body of work on investment in electricity generation and the energy transition, particularly in the industrial organization and macroeconomics literatures (see Kellogg and Reguant (2021) or Fabra and Reguant (2024) for surveys). This includes investment in renewables (Arkolakis and Walsh, 2023; Gonzales et al.,

2023; Butters et al., 2025), fossil fuels (Cicala, 2015; Gowrisankaran et al., 2024), and their interaction (Abuin, 2024; Adrian et al., 2022). Much of this literature focuses in particular on the details of utility regulation, vertical integration, or spatial market integration in the presence of externalities. Our contribution to these broad literatures comes from our focus on the financing side of investment, including our emphasis on how technology-specific risk and financial frictions drive project discount rates and have thus a large impact on investment dynamics. In this area, we relate most closely to recent work on power purchase agreements in particular, including how counterparty risk in PPAs can undermine renewable investment (Ryan (2021) and Fabra and Llobet (2025a)) and the role of PPAs in reducing risk (Fabra and Llobet (2025b)). We extend this line of thinking with a novel macro-finance perspective that argues that "de-risking" cash-flows is valuable because of financial frictions and a capital structure channel, a notion that is very important in practice but understudied in this literature.

Second, we relate to a growing literature on the drivers of green finance, broadly defined; see Giglio et al. (2021) and Hong et al. (2020) for surveys.[13] While many works in this area focus on non-pecuniary preferences of investors for green projects, or financial motives to hedge climate transition risks, our focus is on *technology*-specific risks. In the finance literature, our study relates most closely to Andonov and Rauh (2022) who find a significant change in ownership of new forms of electricity generation in the U.S. away from traditional regulated utilities, including the rise of IPPs in deregulated states and private equity owners. We build on their work by developing a model of the economics of independent power producers, rather than the regulated utilities that have received more attention in the industrial organization literature. We also complement their focus on equity ownership and regulation by emphasizing the role of debt financing, risk, and financial frictions. We stress the importance of discount

[13]Research on corporate finance includes Hartzmark and Shue (2023); Bellon (2021a,b); Bellon and Boualam (2024); Duchin et al. (2022); Shive and Forster (2020); Bai and Wu (2024); Bartram et al. (2022); Feldhütter and Pedersen (2025); De Haas et al. (2025). Research on financial markets includes Giglio et al. (2023); Green and Roth (2021); Baker et al. (2022); Flammer (2021); Pástor et al. (2021); Pedersen (2023); Chittaro et al. (2025).

rates for investments, in line with recent work by Gormsen and Huber (2025) and Gormsen et al. (2024). Our focus on risks in clean energy investment is shared with Acharya et al. (2025) and Fuchs et al. (2024), who focus on a real option channel, as well as Hong et al. (2025), who focus on a diversification channel. We add to these works by focusing on power purchase agreements in project finance, emphasizing the role of financial frictions and introducing a capital structure channel. We relate directly to Lanteri and Rampini (2023) and Darmouni and Zhang (2024) that studies the effect of limited plegeability on the transition to clean technologies but abstracts from risk. We also relate to empirical studies of project finance (Green and Vallee, 2025; Sastry et al., 2023; Berg et al., 2024; Garrett and Shive, 2022). We also draw analogies to the literature on blended finance, which considers how public and philanthropic funding can adopt financial structures to "de-risk" projects and crowd in private capital (Flammer et al., 2024). Consistent with this literature, we show how state-dependent government investment studies can help to stabilize private investment.

Finally, our results on macroeconomic risk connect to a growing body of work studying the links between climate, energy and the macroeconomy; see Bilal and Stock (2025) for a survey. Examples include Barrage (2023), Bakkensen and Barrage (2025), Acemoglu et al. (2023), Barrage (2020), Känzig et al. (2025), Bilal and Känzig (2024), Chittaro et al. (2025), Papoutsi et al., Bistline et al. (2023), and Mehrotra (2024) which focus on other macroeconomic impacts of the transition, such as loss and damage functions, productivity changes, and adaptation. Our main contribution to this literature centers on how the macroeconomic cycle, and in particular inflation spikes, can impede renewable investment through a financing channel. We nevertheless abstract from the macroeconomic link between investment today and future electricity prices that features centrally, for instance, in Arkolakis and Walsh (2023) or Mehrotra (2024).

2 Background on investment in electricity generation

2.1 The changing composition of U.S. power generation

Electricity generation in the United States is undergoing a major transition driven by rising electricity demand, aging infrastructure, and decarbonization goals. Many thermal plants built in the mid-20th century are reaching the end of their operational lifetimes, while electrification in transport and data centers are expanding demand. According to the Department of Energy (DOE)[14] national peak load is projected to rise by nearly 15 percent between 2024 and 2030 and data centers alone will add around 50 GW of continuous load by 2030—roughly equivalent to the entire electricity demand of California. At the same time, a large share of the existing generating fleet, in particular older coal and gas plants, is reaching retirement age, with about 104 gigawatts of generating capacity (roughly 10 percent of the U.S. total) scheduled to go offline by 2030. Meeting this rising demand will require large-scale investment in new generation capacity.

As shown in Figure 1, virtually all newly installed and planned generating capacity in the United States comes from solar (often paired with battery storage), wind, and gas plants. Solar alone accounts for more than 50% of planned additions through 2027. We therefore focus our analysis on these three technologies – solar, wind, and gas – which together represent nearly the entirety of planned U.S. capacity additions.

Gas and renewables are fundamentally different technologies for producing electricity. Gas plants generate electricity by purchasing and burning gas to drive a turbine and can rapidly adjust output to meet changes in demand. Renewable energy technologies such as solar photovoltaic and wind power convert available natural resources available for free directly into electricity with no fuel input but have limited ability to adjust output. These technological differences in (i) input price volatility (ii) operational flexibility are crucial for understanding their respective financing structures. As we show in Section 3, these differences are central to

[14] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (U.S. Department of Energy, 2025)

understanding why renewables tend to rely on project finance and PPAs, whereas gas plants are financed more often on-balance sheet.

2.2 Market restructuring and the rise of independent power producers

Over the past decades, the U.S. electricity sector has undergone a structural transformation driven by market restructuring (deregulation) and the accompanying rise of independent power producers (IPPs). Historically, electricity generation, transmission, and distribution were managed by vertically integrated utilities operating under rate-of-return regulation, with limited incentives for efficiency or innovation. The Energy Policy Act of 1992 and FERC Orders 888 and 889 (1996) introduced competition by requiring open access to transmission networks and establishing Independent System Operators (ISOs) to manage wholesale markets. This restructuring separated generation from regulated distribution and enabled IPPs – firms that own and operate generation assets but do not manage transmission or distribution networks – to compete.

Over the past twenty years, IPPs have displaced regulated utilities as the dominant investors in new generation capacity (Andonov and Rauh, 2022), with their share of total capacity additions increasing to nearly 80 percent by 2024 (see Figure 2). This is true despite IPPs facing regulatory frictions in some regions like the Southeast and part of the West. This aggregate dominance is entirely driven by the rise of renewable energy projects, which are overwhelmingly developed and financed by IPPs. IPPs raise capital from private markets typically through project finance structures secured by project-specific cash flows. Unlike traditional utilities, IPPs face market-based pricing and bear investment risk directly.

The rise of IPPs as the primary developers of renewable energy fundamentally changes how investment in electricity generation is financed. This paper examines the economic mechanisms that enable IPPs to raise private capital for renewable projects, with a focus on how long-term PPAs mitigate revenue risk and reduce financing costs but potentially increase exposure to

macroeconomic risk. Our focus on the IPP segment complements prior research on regulated utility investment (Gowrisankaran et al., 2024), whose cost-of-service regulatory framework creates fundamentally different financial incentives and risk-return dynamics.

2.3 The role of project finance and power purchase agreements

Power Purchase Agreements (PPAs) are the contractual foundation of project finance in renewable energy. A PPA is a long-term agreement, typically lasting 10 to 25 years, between a power producer and a buyer (usually a utility or large corporate off-taker) that guarantees the sale of electricity at a pre-agreed price. These contracts are almost always signed before construction begins, often several years in advance. In a project finance structure, lenders extend credit solely based on the specific project's risks and future cash flows through a special-purpose company established to own and operate the plant. Lenders typically have either no recourse or only limited recourse to the parent company that develops or sponsors the project (the "sponsor"), meaning they cannot claim the sponsor's capital or assets to repay the debt incurred by the special-purpose vehicle (SPV) that owns and operates the project.

By locking in both a stable price and a creditworthy counterparty, the PPA provides renewable projects with a predictable cash flow stream. This long-term revenue certainty is often seen as a necessary condition for lenders, making renewable energy projects "bankable" (Pombo-Romero et al., 2024; Raikar and Adamson, 2024). Consistent with this view, we show in Figures 3 and 4 that renewables are more likely to rely on project finance and PPAs, in contrast to fossil fuel plants. Renewable projects are more likely to (i) be developed by independent power producers (rather than utilities), (ii) rely on off-balance sheet special purpose vehicles, and (iii) have a PPA in place. The left panel of Figure 3 uses detailed regulatory generator-level data from the EIA to show that over 80% of installed renewable capacity is financed by IPPs.[15] For fossil fuels, the share is below 40%. Consistent with that, the right panel of Figure 3 tracks the share of capacity from generators with "LLC" ("limited liability

[15]The EIA defines IPPs as limited liability, investor-owned special purpose vehicles that generate electricity for sale to utilities and other off-takers.

company") in their name and documents a nearly identical pattern. These LLCs typically represent off-balance sheet special purpose vehicles. Figure 4 complements this evidence by documenting the prevalence of PPAs among renewables. We combine two complementary data sources: utility PPAs, which must be reported to the Federal Energy Regulatory Commission (FERC), and corporate PPAs, typically signed by large technology firms such as Meta, Amazon, and Google, as compiled by Bloomberg New Energy Finance (BNEF). Together, these data show that nearly all renewable projects developed by IPPs operate under a PPA. For fossil fuels, the share is less than 15%.

2.4 Data

We combine data from a variety of sources on both the financial and real aspects of electricity investment, linking project-level information on investment and financing structures with technical and regulatory characteristics of installed and proposed U.S. power plants. This data is complemented with regional monthly wholesale and retail electricity prices, as well as public and corporate PPA prices.

U.S. Energy Information Administration (EIA). We use detailed plant-level data from the *EIA-860* and *EIA-923* surveys, which provide comprehensive information on planned and installed capacity, electricity generation, ownership structure, primary fuel inputs, and operating costs. We also incorporate EIA data on electricity and gas prices, construction costs, as well as utility-level revenue and financial information.

Lawrence Berkeley National Laboratory (LBNL). We compile information on power purchase agreements (PPAs) involving utility off-takers from the *Utility-Scale Wind and Solar Markets* reports produced by LBNL. This data includes PPA execution dates, contract duration, prices, technology type, and project location, which we match to EIA plant identifiers where possible.

National Renewable Energy Laboratory (NREL). We draw on detailed estimates of

capital expenditure (CAPEX), levelized cost of energy (LCOE), and weighted average cost of capital (WACC) components by technology and over time from NREL's *Annual Technology Baseline (ATB)* and related datasets. This data provides a consistent benchmark for technology cost trends and financing parameters.

IJ Global. We use transaction-level data on energy investment from IJ Global, which primarily covers U.S. energy projects financed through project finance structures. Each record includes information on financial close date, debt and equity composition, lender and sponsor identities, total investment cost, and project technology.

Federal Energy Regulatory Commission (FERC). In addition to the LBNL data, we use regulatory micro-data from FERC's *Electric Quarterly Report (EQR)*. These filings report detailed contractual information for PPAs involving predominantly public utilities, including counterparties, contract capacity, and pricing.

3 Evidence on costs and risk across technologies

Our framework builds on five key facts, which we link together to form a coherent picture of financing needs, cash flow risk, and bank finance.

3.1 Differences in upfront investment costs

Renewable plants and fossil fuel plants use different production technologies to generate electricity. One key aspect that impacts the economics of financing is the difference across technologies in the upfront (fixed) capital cost required to build a project, which can be seen in each technology's levelized cost of energy (LCOE). The LCOE (expressed in \$/kWh) is essentially the discounted cost of electricity generation over a generator's lifetime.[16] Figure 5

[16] A key advantage of LCOE is that it accounts for differences in capacity factor across technologies. Capital costs per unit of nameplate capacity are potentially misleading. For instance, a gas plant costs significantly more than a solar plant per unit of nameplate capacity, but the capacity factor of a typical gas plant is often more than twice that of a solar plant. Capital costs per unit of annual output are thus lower for gas, something

uses data from the EIA to break down the LCOE of renewable versus gas plants into various components. Capital costs account for nearly 80% of the LCOE for renewables, compared with only one-third for gas plants. This is one factor that can make renewables more affected by financing constraints, since more of the costs have to be covered upfront before any operational profit is realized.

3.2 Flexibility of production

A second key technological difference is the flexibility of production. Renewable output fluctuates mainly due to the availability of solar and wind resources, with storage providing some smoothing over short periods of time. By contrast, gas plants can ramp up or down relatively quickly to meet demand when needed. In electricity market parlance, fossil fuel generation is "dispatchable" and renewables are largely "non-dispatchable". In economic terms, fossil fuel plants, especially gas plants, have a higher price elasticity of supply relative to renewables.

We use detailed regional data from the EIA to show evidence of these differences. Table 1 reports regressions of monthly state-level generation on monthly local wholesale electricity prices for different technologies. We include year and state fixed effects. We account for heterogeneity in gas plants by separating them into three categories. Gas generation strongly responds to fluctuations in market prices, with stronger response for gas "peaker" plants which run when demand increases the most. On the other hand, all types of renewables show no significant response. This provides evidence that renewables are less dispatchable than fossil fuels.

However, we note two challenges to our interpretation of these results as reflecting supply elasticities. First is the usual endogeneity issue that regressing quantities on prices conflates supply and demand. We argue that while an overall supply elasticity is difficult to ascertain due to simultaneity bias, our estimates of relative differences in supply elasticities are less vulnerable to this concern because we compare different sources of electricity supply facing

that the LCOE captures.

the same local demand. Since electricity output in a given area is a homogenous good, there are not technology-specific demand curves by location, allowing us to interpret the difference in the coefficients between gas and renewables is therefore indicative of differences in supply elasticity. A second concern might be that the price sensitivity for natural gas may reflect the fact that natural gas input costs are positively correlated with electricity prices (see Section 3.3), which would impact supply decisions for gas plants specifically and not renewables. However, we estimate a strongly positive coefficient on electricity prices for gas plants, while higher fuel costs would push in the other direction.

3.3 Input price volatility

Renewables produce electricity from freely available natural resources. In contrast, gas plants must first purchase gas (in their input market) to produce and sell electricity (in their output market). Using regional price data, we find that the price of gas is volatile and that this market volatility is not offset by electricity prices (Table 2).

To understand this, it is useful to start with a formula for the profits of a stylized gas plant. Its operating profit margin is the difference between the price of one unit electricity and the cost of producing it, say $p_t - c_t$. Focusing on fossil fuel costs c_t, the cost of producing one unit of electricity is the product of two terms: (i) the price of gas, and (ii) the efficiency of the plant, i.e. how many units of gas it takes to produce one unit of electricity (this is also known as the plant's "heat rate"). Defined this way, the margin $p_t - c_t$ is commonly referred to as the "spark spread" in the industry. The variance of this spark spread is a key component of cash-flow risk for a gas plant. When the spark spread increases, a plant is more profitable. When it decreases, profitability decreases. For illustration, Figure 6 plots electricity prices and gas costs for seven regional U.S. electricity markets. The gap between the two, the spark spread, clearly fluctuates over time in all markets.

We empirically decompose the variance of the spark spread in different U.S. electricity markets using regional gas and electricity prices from the EIA. Note that there are three

terms behind this variance:

$$Var[p_t - c_t] = Var[p_t] + Var[c_t] - 2CoVar[p_t, c_t]$$

The first term is the variance of electricity prices. Both gas and renewable plants are exposed to this variation in output prices. The last two terms are specific to gas plants. The second term captures the volatility of the price of gas, which everything else equal makes gas plants cash-flow more risky. However, the third term importantly captures the fact that electricity and gas prices are, to some extent, correlated. This correlation between input and output prices creates a potential for hedging electricity prices that is unique to gas plants. Because the second and third terms go in opposite directions, it is an empirical question how the presence of input market volatility affects the risk of gas plants overall.

Table 2 presents the results. Row 7 and 8 in the third panel show that there is substantial volatility in both electricity and gas prices. Interestingly, row 9 shows that the spark spread is also highly volatile. The standard deviation of the spark spread (row 6) is two times larger its mean (row 3), while for both electricity prices and gas costs the ratio is less than one (row3/row1, row5/row2). As a result, the variance of the spark spread is in fact not much lower than the variance of electricity prices. Electricity and gas prices on average have a positive correlation coefficient of 0.54 (row 12) due to the fact that gas plants are often the marginal source of power in many markets.[17] However, this correlation is not large enough to offset the volatility in electricity prices. If the correlation was very high, the volatility of the spark spread would be significantly smaller than the volatility of electricity prices.

This has important implications. Gas plants are not "naturally" hedged even if the price of their inputs correlates with their output price. This means that their cash-flows are substantially volatile absent any risk management measures. Moreover, gas projects face market volatility from both the output and input side. This is in contrast to renewables which, due

[17] The implied correlation coefficient can be computed with the following formula: $\rho_{p,c} = \frac{Var[p_t]+Var[c_t]-Var[p_t-c_t]}{2\sqrt{Var[p_t]Var[c_t]}}$.

to their near-zero marginal cost, only face market volatility from the output side. Removing electricity price volatility only would still leave substantial volatility for a gas plant. Row 10 shows that the variance of fuel cost is on average still a third of the spark spread variance.

3.4 Macroeconomic risk

We next turn to macroeconomic risk in electricity production. While studies of electricity markets often emphasize microeconomic factors behind prices, we argue below that correlations with macro factors are also important to understand the economics of investment and financing. Table 3 uses EIA data to examine correlations between monthly wholesale electricity prices, factor returns, and macro variables. There is a strong correlation between electricity prices and aggregate core inflation. This is natural but not mechanical, since core inflation excludes energy prices. For completeness, we show this relationship is robust to controlling for short-term and long-term interest rates, which also move contemporaneously given the desire of the central bank to fight inflation. Finally, electricity prices are largely uncorrelated with aggregate stock returns using a range of traditional and production-based asset pricing factors. This lack of correlation has important financial implications, as explained below.

The strong correlation with core inflation suggests that when electricity prices are high, the cost of building new plants is also high. This is a particularly important point for this paper, so we provide direct evidence of that link using CAPEX forecast data from NREL. Figure 7 shows that capital costs are significantly higher after 2022 for all types of technologies. After many years of continuous decline, the cost of building plants increased during this inflationary episode. This is in line with the sharp increase in the price of capital goods during this time due to supply chain bottlenecks and higher production costs (Darmouni and Sutherland, 2024). In terms of magnitude, the shift was comparable to between five and ten years of "learning by doing" cost reduction for renewables, and even more for gas. The shift also indicates that this macro shock was largely unexpected.

3.5 PPA prices

We compile detailed PPA price data over time to understand their dynamics. We construct PPA price indices for wind and solar combining price data from LevelTen Energy on corporate PPAs and from the Berkeley Lab on utility PPAs. Figure 8 plots the PPA price indices together with average retail electricity prices. We see a large increase, with PPA prices rising by roughly the same amount for both wind and solar over this period. The figure shows that this increase closely tracks the increase in electricity prices, which also increased by approximately 30$ per MWh over the same period. (Note that there is of course a difference in levels, since PPAs do not, for instance, include factors like transmission and distribution costs.)

The correlation between changes in PPA and retail prices suggests that shocks to electricity prices are perceived to be relatively long-lasting, at least during this episode. Indeed, because PPAs have a typical horizon of 10 to 15 years, their price level should reflect average electricity prices over that horizon. A long-lasting shock would move PPA prices but a short-term transient shock would not.

4 A model of financing investment in electricity

4.1 Overview

We provide a framework to understand the financing of investment in electricity generation. The model builds on the previous empirical evidence to explain why the project finance structure arises and what are its implications for investment dynamics. Our baseline model is purposedly stylized to make the point as transparently as possible. In particular, we abstract from much of the complexities of market structure, regulation, and infrastructure that tend to vary across fragmented regional markets. Note that, for instance, in a few markets regulation heavily penalizes IPPs: our baseline model naturally does not apply as such to these settings. More generally, there are many potential extensions that could be incorporated, and we list a

few below.

We take a net present value (NPV) approach to investment decisions. An investment should be undertaken when its NPV is positive. Conceptually, it is useful to break down a project's NPV into two components: its *internal rate of return* (IRR) and its *discount rate* (often referred to as its (weighted-average) cost of capital, or WACC). The IRR is essentially the expected (annualized) rate of return of the project's future profits relative to initial investment.[18] A project's discount rate is its opportunity cost, i.e. the rate of return on the next best comparable project. The investment has a positive NPV as long as its IRR exceeds its discount rate:[19]

$$NPV > 0 \iff IRR > \text{discount rate}$$

This section develops a simple perpetuity model of energy investment that nests both renewable and fossil fuel technologies. We first focus on cash-flow risk (once operations have started), while a later sector will introduce macro-economic risk (before construction is undertaken).

4.2 Operating profits and IRR

Consider a power plant that produces electricity in perpetuity. The plant has a maximum nameplate capacity K. (Scaled) operating profits in year t are given by $\pi_t/K = q_t/K \times (p_t - c_t)$. These profits are stochastic, determined by the following three quantities. p_t is the market price of electricity, which determines revenues. c_t is the plant's operating costs, which for simplicity only include variable costs. The difference $p_t - c_t$ is the plant's (operating) profit margin. q_t/K is the plant's capacity factor, defined as the ratio of its electricity output to its nameplate capacity. Formally, each is determined by its own equation:

$$p_t = \bar{p} + a_p s_t + e_{p,t}$$

[18] Mathematically, the IRR of a project's stream of future cash-flow (including initial investment costs) is the discount rate that makes the project's NPV equal to zero.

[19] As long as projected cash-flows satisfy a regulatory condition, which typically holds in the context of energy projects.

$$c_t = \bar{c} + a_c s_t + e_{c,t}$$

$$q_t/K = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$$

The first equation assumes that electricity prices p_t stochastically fluctuate around their expected value $\bar{p}$. Electricity prices are affected by an aggregate shock s_t representing the state of the economy that can affect other variables, as well as an idiosyncratic shock. Similarly, c_t the cost of operating the plant fluctuates around its expected value $\bar{c}$, subject to potentially both aggregate and idiosyncratic shocks. Finally, the plant capacity factor is on average equal to θ, but might adjust depending on the parameter ξ that reflect the price elasticity of supply. Output will go up or down depending on whether profit margins are unexpectedly high or unexpectedly low.[20]

While both renewables and fossil fuel plants face the same stochastic electricity price, the parameters underlying their cost and output are different. In terms of costs, a renewable plant has near-zero, a-cyclical production cost, implying that both the average variable cost $\bar{c}$ and the loading a_c on the aggregate state are low. On the other hand, gas plants have to purchase fuel to produce electricity, so $\bar{c}$ is substantially higher. The price of gas might also be cyclical, which would impact the value of the loading a_c. The two technologies also diverge in terms of capacity factor. Importantly, gas plants are technologically more flexible, the parameter ξ is positive. For renewables, the parameter ξ is much smaller, often close to zero. The baseline capacity factor θ is also typically higher for modern gas plants than renewables.

The IRR of the project is determined by the flow of expected operating profits $E[\pi_t/K]$ as well as investment costs (CAPEX) i (in \$ per unit of nameplate capacity K). For ease of illustration, in this section we provide close-form formula for a stylized perpetual plant that

[20]This linear supply function can be micro-founded with a production function with quadratic adjustment costs. Assume that the plant maximizes $q_t p_t - c(q_t)$, where $c(q_t) = c_0 + c_t q_t + \frac{1}{2\xi}(q_t - \bar{q})^2$. The first order condition implies that $q_t = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$ as above, where $\theta := \bar{q} + \xi(\bar{p} - \bar{c})$.

produces every period:[21]

$$IRR = \frac{E[\pi_t/K]}{i}$$

The calibrated model below incorporates additional realistic features, including capital depreciation, corporate tax, fixed operational costs, or interconnection costs. This section also abstracts away from the arrival of news about cost shocks, but that is the subject of Section 6.

4.3 Financing and discount rates

Although many existing work on energy investment take discount rates as given, foundational finance theories emphasize that they are endogenous to risk and capital structure.

4.3.1 Frictionless benchmark

The classical frictionless theories such Modigliani-Miller implies that a project's discount rate is entirely driven a single variable: its systematic risk. Systematic risk, sometimes called aggregate or market risk, is measured by the project β ("beta") which is simply defined as the regression coefficient between the project's risky returns and aggregate stock market returns. Other forms of risk do not require risk compensation because they are diversifiable and thus do not create risk at the portfolio level. Note that this logic extends to richer "factor models" beyond the CAPM that have been proposed in the past decades. However, the fourth fact above shows that electricity prices are at best weakly correlated with the main stock market factors. The presence of a PPA is thus unlikely to dramatically change the systematic risk of a project. For ease of exposition, we therefore generally abstract from this qualitatively weak systematic channel.[22]

[21] Mathematically, the IRR solves $\sum_t E[\pi_t/K]/(1+IRR)^t - i = 0$, which simplifies to our expression thanks to the perpetuity formula. The current formula assumes no subsidies. Adding production tax credits s^q and investment tax credits s^i leads to $IRR = \frac{E[\pi_t/K]+s^q}{i(1-s^i)}$

[22] That does not mean that systematic risk or that CAPM betas do not matter for discount rates and corporate investment in general. Only that these forces are unlikely to be significantly affected by a PPA.

4.3.2 Financial frictions

Absent financial frictions, the famous Modigliani and Miller's irrelevance theorem shows that discount rates are independent of capital structure. In other words, how the project is financed, i.e. the mix of debt and equity financing, does not impact the value of the project. However, it is well understood that in practice financial frictions exist and are a first-order driver of investment decisions. Frictions that have been studied to rationalize a role for capital structure include agency costs, inefficient bankruptcy and liquidation, and taxes (see Graham and Leary (2011) for a survey). In line with classical finance research, we model the financial side such that having more debt (i.e. "leverage") and less equity financing lowers the discount rate. Our framework consists of two components. First, there are risk-based debt limits. Second, substituting debt with equity is costly: there is an excess (risk-adjusted) cost of equity financing.

Risk-based debt limits: We model the idea that lower cash-flow risk (including "diversifiable" risk) facilitates debt financing. The model is in line with how debt sizing is done in practice for project finance, consistent with the idea that low-risk is necessary to make the project "bankable."[23] Annual operating profits (scaled by capacity) are random as above, with $\pi_t/K \sim F$. Debt contracts are perpetual (to match perpetual cash-flows), paying a coupon rate r^D on face value D. The annual debt service is thus $r^D D$. Default occurs if $\pi_t/K < r^D D/K$.

The project can borrow from a set of competitive lenders. Assume lenders target a probability of default, say α.[24] This corresponds to an interest rate r^D, which include a risk premium for default risk. Setting a target for default risk is equivalent to setting a risk-based

[23] See for instance Chapter 4 in Raikar, Santosh, and Seabron Adamson. Renewable Energy Finance: Theory and Practice. London, England: Academic Press, 2020. Print.

[24] This is consistent with how lending is done in practice, but per se this is not a deviation from MM. The deviation from MM will come from an excess cost of equity financing.

borrowing limit:

$$P(\text{default}) \leq \alpha \iff P(\pi_t/K < r^D D/K) \leq \alpha \iff D/K \leq F^{-1}(\alpha)/r^D$$

This can be re-written more intuitively if we first note that $F^{-1}(\alpha)$ is the α percentile of operating profits, $\pi_t^\alpha/K := F^{-1}(\alpha)$. To isolate the effect of risk, we define the borrowing limit Λ relative to average profits $\bar{\pi}_t/K$:

$$D/K \leq \underbrace{\Lambda}_{:=\frac{\pi_t^\alpha/K}{\bar{\pi}_t/K}} \frac{\bar{\pi}_t/K}{r^D} \tag{1}$$

Intuitively, projects with lower cash-flow risk can borrow more. For the same target default probability α and the same average profits, safer projects have a higher α percentile of profits, implying a higher debt limit Λ. This gives a natural channel for any "de-risking" of cash-flows to boost leverage and reduce the project's discount rate. An interpretation of the debt limit Λ that is consistent with practice is in terms of target interest coverage ratio. This ratio is defined as operating profits over debt service, i.e. $\pi/r^D D$. Using a similar logic to the model above, bankers typically target coverage ratios to be maintained relative to expected operating profits. In the model, the target coverage ratio is simply $1/\Lambda$. A lower coverage ratio implies more debt financing.[25]

A natural micro-foundation for this part of the model is that in practice banks have incentives to keep the risk of their loans in check. Both regulation (e.g. risk-based capital requirements) as well as market discipline (e.g. the risk of deposits withdrawals) induce banks to make relatively safe loans. If loans are securitized, a good credit rating is also important to maximize the demand from institutional investors.

WACC and leverage: The amount of debt financing ("leverage") matters for the project's

[25]Note that this is a model driven by quantity rationing, in line with practice. The interest rate r^D does not change with debt size D and is not very sensitive to the project's characteristics. Debt size D is where most of the action is: it adjusts to keep default risk (and thus interest rates) constant.

discount rate in the presence of financial frictions. The key force is the existence of and "excess cost of equity". We model the discount rate based on a classical weighted average formula:

$$WACC = \underbrace{r^D}_{\text{cost of debt}} + \underbrace{(1-l)}_{\text{leverage}} \underbrace{(r^E - r^D)}_{\text{excess cost of equity}}$$

In a Modigliani-Miller world, the excess cost of equity increases with leverage in a way that exactly cancels out: $r^E - r^D$ is proportional to $1/(1-l)$ so that the overall WACC is unaffected by leverage. We deviate from this perfect benchmark by assuming that equity financing is excessively costly and that the WACC declines with leverage. This is a common feature in macro-finance models that often assume a convex costs of (outside) equity issuance, or assume this cost is infinite. A reduction in leverage has thus a strong effect on increasing discount rates.

We do not explicitly micro-found the wedge. One possibility perfectly consistent with our focus on bank debt above is the existence of government guarantees and deposit insurance. These public backstops make bank debt "cheap" relative to alternatives form of financing. Other well-known possibilities include a tax advantage of debt or asymmetric information. In principle, our main conclusions are not driven by exactly which forces are behind this wedge.

We parametrize the discount rate in the following way. We follow this approach and assume that some underlying frictions imply that the excess cost of equity *decreases with leverage*. The more equity financing, the more expensive it becomes. The excess cost of equity is given by $r^E - r^D = (1-l)\chi_e$, where χ_e represents the excess cost of equity for a fully equity-financed (unlevered) project. The WACC formula thus reduces to:

$$WACC = r^D + (1-l)^2 \chi_e$$

For tractability, we proxy leverage by $l = \frac{D/K}{i}$, the share of investment cost covered by debt financing.[26]

[26] If the project's NPV is small, this is close to leverage in terms of market value.

5 The value of project finance

5.1 Power Purchase Agreements (PPAs)

We model power purchasing agreements (PPAs) as long-term contracts to sell electricity at a pre-agreed price. To focus on the role of cash-flow risk, the baseline model purposely focuses on *fair and permanent* PPAs. In other words, a PPA is modeled as a commitment to sell the plant's expected output at the average expected market price. Formally, this amounts to $p_t^* = \bar{p}$ and $q_t/K = \theta$ for all future period t. Recall the equations determining electricity prices p_t and q_t/K,

$$p_t = \bar{p} + a_p s_t + e_{p,t}$$

$$q_t/K = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$$

In that setting, a PPA is thus equivalent to two things. First, it removes all sources of risk in electricity prices. Second, no production flexibility, i.e. $\xi^{PPA} \approx 0$. In this sense, a PPA's main effect is the "de-risking" of revenues.

We make two comments on our modeling choice. First, we abstract away from any imperfections in PPA contracts (opportunistic renegotiation, counter-party risk, etc..). Clearly, these have negative effects on investment that are well understood Fabra and Llobet (2025a,b); Ryan (2021). Our contribution is to point out a novel financing channel, and to illustrate that as clearly as possible we show that even fair and permanent PPAs can have pros and cons. Second, we also take these contracts as given and study the impact on investment, i.e. we do not model the supply side of PPA in this paper.[27] This important question is beyond the scope of this paper.

[27]Firms taking the other side of PPA involve a variety of actors, from regulated utilities, tech firms, or public entities, having widely different constraints and objectives.

5.2 Effect on IRR

The first main result is that even a fair and permanent PPA significantly reduces the IRR for a fossil fuel project, but not for a renewable project. To see this, note first that expected profits without a PPA can be decomposed in the following way:

$$E_{noPPA}[\pi_t/K] = \underbrace{E[q_t/K]}_{\text{av. production}} \underbrace{E[p_t - c_t]}_{\text{av. margin}} + \underbrace{Cov(q_t/K, p_t - c_t)}_{\text{option value from flexible production}} = \theta(\bar{p} - \bar{c}) + \xi Var[p_t - c_t]$$

When production is flexible ($\xi > 0$), expected profits (1st moment) depends on variance of profits (2nd moment). Intuitively, this comes from the option value of adjusting scale ex-post: adjusting output up and down when the market prices of electricity and gas fluctuate. The option value of adjusting scale is ex-ante profitable and increases with the underlying variance.

On the other hand, with a PPA, expected profits are given by:

$$E_{PPA}[\pi_t/K] = \theta(\bar{p} - \bar{c})$$

It is clear that when production is flexible, these expected profits are lower $E_{PPA}[\pi_t/K] = \theta(\bar{p} - \bar{c}) < E_{noPPA}[\pi_t/K]$. This is because even a fair and permanent PPA undermines that option value by locking in quantity and price ahead of time. This implies that the IRR *declines* for a project for which a significant share of output is expected to come from production flexibility.[28]

This, however, is not the case for renewables, because they have low production flexibility: adjusting output to market prices is technologically difficult, if not near-impossible without storage. Because of that, a PPA does not reduce expected profits through this channel like it does for flexible gas plants. When $\xi \approx 0$, $E_{PPA}[\pi_t/K] = E_{noPPA}[\pi_t/K]$

This is the first key reason for why PPAs are appealing for renewable investment specifi-

[28]Note that there is also some heterogeneity within gas plants in this dimension. Newer, more efficient generators are dispatched more often, while older "peaker" plants have more volatile output. In some markets, gas plants also receive capacity payment independent of output. However, the rise of inelastic and intermittent renewable sources has increased the value of production flexibility for gas plants.

cally: a PPA can de-risk revenues without hurting expected profits much. It also means that the potential of a PPA to increase NPV and investment is through *a discount rate channel*, which we turn to next.

5.3 Effect on discount rate

Next, we show that the project finance structure significantly reduces the discount rate for a renewable project but not necessarily for a fossil fuel project.

We argue that the *capital structure* channel is of first-order importance. The main benefit of de-risking cash-flows via PPAs is due to financial frictions. A reduction in cash-flow risk endogenously increases debt limits. This in turn, implies less use of expensive equity financing. For renewables it is very clear that a PPA reduces the variance of profits. Formally:

$$Var_{noPPA}[\pi_t/K] = \theta^2 \underbrace{var[p_t - c_t]}_{\text{variance of margins}} = \theta^2(\underbrace{a_p^2 var[s_t] + var[e_t^p]}_{\text{electricity price risk}} + \underbrace{var[e_t^c]}_{\text{cost risk}})$$

With a PPA, all terms disappear except the last one:

$$Var_{PPA}[\pi_t/K] = \theta^2 var[e_t^c]$$

Which is very small since operating costs are small for renewables.[29]

Recall the expression for debt limits:

$$D/K \leq \underbrace{\Lambda}_{:=\frac{\pi_t^\alpha/K}{\bar{\pi}_t/K}} \frac{\bar{\pi}_t/K}{r^D}$$

A PPA increases debt limits for renewable because (i) a decline in variance leads to a rise in

[29]The idea still applies even in the presence of production shocks from renewables due to random variation in natural conditions. The baseline models can be easily extended to incorporate such shocks. Assume that the plant's capacity factor is given by $q_t/K = \theta + e_t^q$, with e_t^q independent from other random variables. Then $Var_{noPPA}[\pi_t/K] = (\theta^2 + var[e_t^q])var[p_t - c_t] + var[e_t^q](\bar{p} - \bar{c})$. With a PPA, the variance drops to $Var_{PPA}[\pi_t/K] = (\theta^2 + var[e_t^q])var[e_t^c] + var[e_t^q](\bar{p} - \bar{c})$. This is still significantly smaller as well as being small in absolute value since production shocks average over the entire year in a relatively predictable way.

the factor Λ, and (ii) expected profits are largely unaffected as we saw above. This in turns increase leverage and reduce the reliance on expensive equity financing. The discount rate thus goes down. Again, having these projects off-balance sheet is again helpful to keep these very safe cash-flows from mixing with other risky investments.

The capital structure channel is less straightforward for a fossil fuel plant. On the one hand, there is some de-risking at work, but it is more limited than for renewables. This is because a gas plant faces market volatility not only on the output side but also on the input side. Recall that the third of our initial facts shows that only removing price volatility would still leave substantial variance in operating margins. In other words, a PPA would lead to an increase in the factor Λ but by a smaller amount than for renewables.

This view is consistent with evidence and the role of PPA contracts in facilitating debt financing is clearly acknowledged by practitioners. Bankers explicitly say they set lower debt limits for projects without a PPA, and that the effect is technology-specific. Data from Norton Rose Fullbright illustrate this point. For renewables, a PPA increases the factor Λ by almost 25 percentage points (from about 55% to 80%). For gas, a PPA increases this factor by less than 10 percentage points (from 69% to 76%). We use these numbers in the calibration below to discipline the debt part of our model.[30]

Moreover, an additional core issue for gas plants is that their expected profits go down with a PPA, as we saw above. This endogenously reduces debt limits by making default on a large loan more likely. If that profitability effect is large enough, it can dominate the effect of de-risking. In that case, a PPA actually can reduce leverage and increase the use of expensive equity financing. For these reasons, it is unclear that the project finance structure helps reduce discount rates for such technologies.

[30] In practice, bankers often speak of coverage ratio (which can be mapped to debt limits): *"For contracted wind, expect a coverage ratio of 1.3 to 1.4 times P50 revenue. For a merchant wind project, the coverage ratio is more like 1.8 to 2.0 times P50 revenue. For fully-contracted solar, expect a coverage ratio of 1.25 times P50. Merchant solar is 1.75 times P50 and 1.4 times P99."* Source: Norton Rose Fullbright (2024): https://www.projectfinance.law/publications/2024/february/cost-of-capital-2024-outlook

5.4 Calibration

We take the model to the data to gauge the quantitative impact of these mechanisms. Relative to the baseline model of the previous section, we add a number of realistic features: finite project lifetime, fixed operational and maintenance (O &M) costs, initial interconnection costs, and corporate taxation, including a depreciation and interest rate tax shield. We discipline the parameters of the model by combining micro-data from different sources. First, we use data on market prices for electricity from the EIA. We set the average price $\bar{p} = 30/MWh$ in line with the average wholesale and PPA price pre-2022. We set $var[p_t - c_t] = 50$ to reflect the significant fluctuations in market prices. Given that the correlation with stock market factors is generally low and insignificant, we ignore the systematic risk channel. The corporate tax rate is set to 21%. Second, we use detailed capacity and costs across technologies from LCOE estimates from NREL. We proxy a renewable plant with a typical solar project, with capacity factor $\theta = 25\%$, lifetime of 30 years, no variable operating costs ($\bar{c} = a_c = 0$), fixed unit O &M costs of 15\$, unit interconnection costs of 100\$. We assume no flexibility in production ($\xi = 0$). We set the unit investment cost equal to $i = 1.2M\$$ in line with pre- 2022 values, and account for an investment tax credit of 30%.[31] For the gas project, we set the capacity factor $\theta = 70\%$ and and lifetime of 100 years. We model significant variable operating costs coming from fossil fuel purchases ($\bar{c} = 12$), in addition to fixed O &M costs of 34\$ and initial unit interconnection costs of 100\$. We assume some flexibility in production, with the parameter $\xi = 0.0001$ calibrated to match realistic IRR on the project. We set the unit investment cost equal to $i = 2M\$$ and no tax credits. Finally, we collect data on financial variables. Data on debt limits comes from the target coverage ratios across technologies with and without PPA from Norton Rose Fulbright (2024).[32] For the WACC parameters, we set the cost of debt $r^D = 5\%$, and the excess cost of equity parameter $\chi_e = 20\%$. This allows to match pre-2022

[31] We abstract from the working of tax equity markets and assume that tax credits can be realized immediately to fund the project. On tax equity and banks, see also Garrett and Shive (2022).

[32] Specifically, for solar we use the following coverage ratios: ($k_{ppa} = 1.25; k_{noppa} = 1.75$); for gas we use ($k_{ppa} = 1.3; k_{noppa} = 1.45$).

values for the discount rates from NREL.

We find that the project finance structure increases investment in renewables but not in gas projects. Figure 9a shows the effect of a PPA for a gas project. The x-axis indexes the share of revenues contracted under a PPA. A value of zero corresponds to no PPA, while a value of one to a complete PPA. We observe two things. First, that when a gas plant adopts a PPA, its IRR falls significantly, from 6% to 4.5%. This is consistent with the theoretical prediction above: a large share of the project's IRR is driven by the option value to adjust production. Second, its discount rate does not fall and in fact rises modestly from 4.8% to 5.3%. This means that a PPA turns this gas investment project from positive to negative NPV.

The reason why the discount rate does not fall is due to the capital structure channel. While the PPA increases the factor Λ by a small amount, it also reduces expected profits so much that overall debt limits fall. That forces a rise in equity financing that pushes the discount rate upward. This shows why project finance is typically not the optimal financing structure for a flexible gas project.

The opposite pattern emerges for a solar project, as shown in Figure 9b. A PPA keeps its IRR unchanged around 5.75%. This is because there is no option value in production. The discount rate, however, falls significantly, from 8% to 4.8%. It is thus a discount rate channel that turns the NPV of the investment positive. Quantitatively, a PPA strongly relaxes debt limits and increases leverage. This shows how the project finance structure facilitates financing for renewables specifically.

5.5 Additional implications

Project finance for gas projects: The logic above helps to rationalize why project finance is less common for gas in practice. It also helps to understand why, when project finance is used, it typically takes a different form than for renewables. Given the (risky) cost structure and longer life span of a gas plant, risk mitigation rarely takes the form of PPAs commonly

used for renewables. Instead, it relies on forms of risk management that are more common in traditional corporate finance. The first is the use of financial hedging through derivative contracts with financial institutions. The two most common instruments are heat rate call options and revenue puts. The goal of both instruments is to limit the risk that profits dip too low and debt becomes unsustainable. However, in practice frictions tend to lead to imperfect risk-sharing. Financial institutions with expertise in derivatives, such as dealer banks, face their own constraint and frictions which impede their ability to provide perfect hedging for the risks faced by gas plants. This can create trouble for the project finance structure that is so reliant on debt. The bankruptcy of the Panda Temple gas plant was a heavily publicized recent example of how derivatives were not enough to mitigate cash-flow risk in the face of market volatility.[33] A second form of risk management is frequent debt refinancing and re-contracting. Although a gas plant itself can last for decades, the maturity of debt and other contracts is typically much shorter. For example, five-year loans are common. These loans must be frequently refinanced, sometimes with a change in ownership. Financial contracts also must be renewed frequently to reflect new conditions in electricity and gas markets. This is in contrast with renewables that typically have much longer contract maturities that are closer to the useful life of the asset. These differences are in line with technological differences: operating a gas plant is fundamentally more risky.

Levelized cost of energy: Measures of the levelized cost of energy (LCOE) are widely used to compare the cost of different technologies. One potentially under-appreciated aspect of these measures is that they implicitly depend on the discount rate. Everything else equal, a lower discount rate leads to a lower LCOE. A natural implications of the logic above is that the project finance structure helps keep LCOE low through a lower discount rate. This "hidden" discount rate effect is especially large for renewables with higher initial investment cost. To see this more precisely, in a simple perpetual model the LCOE (absent subsidies) is

[33] "Panda Temple bankruptcy could chill new gas plant buildout in ERCOT market", May 15th 2017, Utility Drive. Source.

given by the following close-form expression:

$$LCOE \approx \bar{c} + \frac{f}{\theta} + r\frac{i}{\theta}$$

The first two terms capture operational costs: $\bar{c}$ is the average marginal cost and f is fixed O&M costs, with θ being the capacity factor. Investment costs are reflected in the last term: i is the investment cost per unit of capacity. Importantly, this cost is multiplied by the discount rate r. A lower discount rate reduces LCOE and especially so for technology for high ratio of investment cost to output i/θ like renewables. More generally, the discount rate is key for innovations that reduce investment cost i to translate into lower LCOEs.

Figure 10 shows that in our main model calibration the LCOE for renewables would be 45% higher without PPAs. This large effect is entirely driven by the capital structure channel. To size the effect of the channel more intuitively, the middle bar shows that the effect is as large as an investment tax credit of 30%, which is the current baseline value for the United States. This suggests that, quantitatively, this financing effect is as potent as existing fiscal policy instruments.

Long-term storage and market volatility: Our model also suggests a complementarity between investment in renewables and innovations that can lower market volatility. For instance, the development of long-term storage technologies has the potential to reduce swings in electricity prices by absorbing shocks to demand or supply. Even though current storage technologies have cycles measured in hours, efforts are directed towards developing storage systems with significantly longer horizons. Our capital structure channel implies that the advent of such technologies could in principle significantly facilitate investment in renewables by lowering the need for a PPAs to raise debt financing.

6 Macro-risk and project finance

6.1 Cost shocks and macro-correlation

However, an important finding is that project finance is not all upside, even for renewables. We identify a novel downside of PPAs: the amplification of macroeconomic shocks. While a PPA reduces risk in operating cash-flows, it leads to more exposure to cost shocks. For this mechanism to exist, there must be a (macro) correlation between electricity prices and investment/financing costs. The inflationary surge of 2022 is a perfect example. We showed above that electricity prices and construction costs both jumped upward during that episode, remaining elevated to this day.

The key point is that a PPA makes it more likely that a project is abandoned ex-post in reaction to bad news. To illustrate this in the clearest possible way, we extend a simplified version of the model above to account for macro-economic risk. Section IA.2 in the Internet Appendix develops a more complete model. Consider a renewable plant with unit capacity and unit capacity factor, with no operational costs and no depreciation. The expected annual future electricity price is p, construction costs i, and the discount rate is r. The project NPV is positive if:

$$p/r - i > 0 \iff p > ri$$

Importantly, these variables are random, but also correlated. There is an aggregate variable s that captures the state of the macro-economic cycle. At the start of development, s is unknown with $E[s] = 0$. At the time of construction, the developer learns s. Expected future electricity prices are given by $p = \bar{p} + as$. Importantly, investment costs also vary with the state s, with $ri = \bar{ri} + bs$. Assume that a and b are both positive: when inflation is high, electricity prices and construction costs are high.[34].

[34]Interest rates can also be high due to the endogenous central bank response to inflation.

6.2 Abandoning investment ex-post

Assume that ex-ante the project is profitable, i.e. $\bar{p} > \bar{ri}$. However, even in that case, the project might be "underwater" by the time construction starts. Absent a PPA, the project is not abandoned if the (interim) NPV is positive:

$$p/r - i > 0 \iff \bar{p} - \bar{ri} > (b - a)s$$

The larger the difference $b - a$, the more likely the project is to be abandoned. The key point is that *ceteris paribus* a PPA makes it more likely that a project is abandoned ex-post. This is because with a PPA the electricity price is set at development, without the knowledge of s. In this case, $a \approx 0$, and the project is abandoned if $\bar{p} - \bar{ri} < bs$, which makes investment more sensitive to the cycle s.

We make three comments on the mechanism. First, a PPA acts as an *amplification* mechanism: investment is still sensitive to the news absent a PPA, a PPA simply increases that sensitivity. Second, it requires a *long-lasting shock* to electricity prices. A temporary shock would only marginally affect the NPV of a long-lived project, and ex-ante PPA prices are not distorted ex-post. Third, there must be a *macro correlation between electricity prices and investment costs*. If not (i.e. $b \approx 0$), a PPA would actually help stabilize investment by removing the variation in electricity prices.

Intuitively, think of a high realization of s, like in 2022. Building a plant is now significantly more expensive. But electricity prices are also higher for the foreseeable future. If the PPA price could be reset, fewer projects would be abandoned.[35] The problem is exacerbated the longer the development time of the project, since this is when PPA prices are typically locked-in. This increase in "development risk" in the face of the macroeconomic cycle is consistent with the recent collapse of offshore wind investment in the United States. Rising input costs and fixed PPA prices rendered many projects unprofitable despite generous subsidies, leading

[35] Here for simplicity we ignore the previous force that a PPA reduces r.

to about $30 billion in cancellations and delays.[36]

Our simple model captures this mechanism quantitatively. Figure 11 shows the evolution of the internal rate of return (IRR) for a representative renewable project subject to a cost shock similar in magnitude to the one observed in 2022-2023. We assume that at $T = 6$, both electricity prices and construction costs permanently increase by 30%. The solid red line illustrates the case where a PPA is in place: the IRR falls by over 2 percentage points, dropping below the discount rate. As a result, the NPV becomes negative, creating incentives to abandon or delay the project. This occurs because construction costs rise while the PPA price remains fixed at its pre-shock level. The dashed red line shows the counterfactual in which the PPA price adjusts ex-post to reflect the cost shock. In that case, a higher PPA price leads to higher revenue that balances most of the increase in investment cost. The IRR falls but remains above the discount rate.

Note that there is no easy solution. First, renegotiating a fixed PPA ex-post is difficult as these contracts are meant to induce long-term commitments. Second, the alternative of writing state-contingent PPAs for which the price resets at the time of construction has an important drawback. It creates cash-flow risk for initial investors and works against the "de-risking" value of PPA emphasized in the previous section. Note also that this issue is not restricted to cost shocks, but also extends to interest rate shocks correlated with electricity prices. This lengthens the list of potential macro variables to index PPA prices to, making efficient state-contingent PPAs complex instruments that might be less appealing to lenders. The project finance structure thus creates an inherent trade-off between the average scale of investment and its volatility throughout the cycle.

Note finally that it is plausible that this macro-risk was under-appreciated by developers and investors. Solar took off around 2014 amid historically low levels of inflation and interest rates. Moreover, construction costs for renewables have been falling every year at an accel-

[36]See e.g., "Cancellations Reduce Expected U.S. Capacity of Offshore Wind Facilities" (EIA, 2024), "Wind Industry in Crisis as Problems Mount" (WSJ, 2023), "The Struggles of the Offshore Wind Industry" (FT, 2023).

erating pace. It is thus possible that the sudden turn taken by the macro-monetary cycle in 2022 was largely unexpected. In fact, there is evidence of this from CAPEX and WACC forecasts from NREL. Figure 7 shows that CAPEX forecasts discretely jump up post-2022. Figure IA.1 in the Internet Appendix shows the same for WACC. This is consistent with a large surprise. There was thus potential for neglected risk in contract design. Recall that if the belief was that there was no macro-risk in construction costs ($b \approx 0$), then a PPA creates no additional risk. In fact, a constant PPA *reduces* volatility by insulating investment from shocks to electricity prices. But that ended up being the opposite of how it played out in 2022. This reinforces one of the key messages of this paper: the need to carefully account for macro-correlations to understand the dynamics of electricity investment.

6.3 State-contingent subsidies

In this last section, we explore potential policy tools to address this volatility in renewable investment. We focus on investment subsidies, like investment tax-credits (ITC), because of their simplicity and prevalence. We show that state-dependent investment subsidies are natural tools in this setting.

Figure 12 illustrates this result in our calibrated model. In the baseline, ITC is constant throughout and equal to 30%. The baseline IRR and WACC in solid red and solid blue are the same as in the previous Figure 11. The NPV turns negative at $T = 6$ after the cost shock. The dashed red line shows the impact of state-contingent subsidies on the project IRR. In that counterfactual, the ITC is contingent on realized construction costs. Instead of being constant at 30%, it is equal to 22% when construction costs are low but increases to 40% when they become high. In that case, the dynamics of IRR are very different: it is stable and constantly above the discount rate (in this example by a small margin). That ensures that the NPV remains positive over the cycle and there are no incentives to abandon the project ex-post. This is achieved by re-distributing the subsidies across the states of the world where they help the most. Relative to the constant subsidies policy, in good times the IRR is lower

but still above the discount rate. In bad times, the IRR is significantly higher and just above the discount rate, triggering investment.

State-contingent policy can help avoid a dry-up of private sector funding in bad economic times. Commitment to a constant policy is thus not always the best way to induce stable investment. Designing energy and climate policy around macro-shocks is a natural implication of our framework.[37] There are nevertheless challenges to this type of policy. It requires commitment to a clear rule; otherwise it can generate substantial policy uncertainty which would hurt investment instead of stimulating it. It can also lead to higher fiscal spending.

7 Conclusion

This paper aims to understand investment in electricity by linking technology and finance. It argues that the widespread adoption of project finance and Power Purchase Agreements (PPAs) is a direct consequence of the unique risk properties of renewable energy technologies. The core mechanism enabling renewable investment operates through a capital structure channel: PPAs significantly de-risk cash flows, which in the presence of financial frictions reduces discount rates by relaxing debt limits. In contrast, power purchase agreements are much less attractive for fossil fuel projects with volatile input prices. However, even for renewables this beneficial financing structure creates an inherent trade-off. By locking in long-term prices, project finance amplifies exposure to macroeconomic risk—especially inflation in construction costs—thereby increasing investment volatility. The post-2021 slowdown in renewable investment illustrates this broader vulnerability to macroeconomic shocks.

[37] There is perhaps a connection with the modern conduct of monetary policy: state-contingent interest rate policy often aims to counteract macro-shocks in order to achieve a long-term inflation target.

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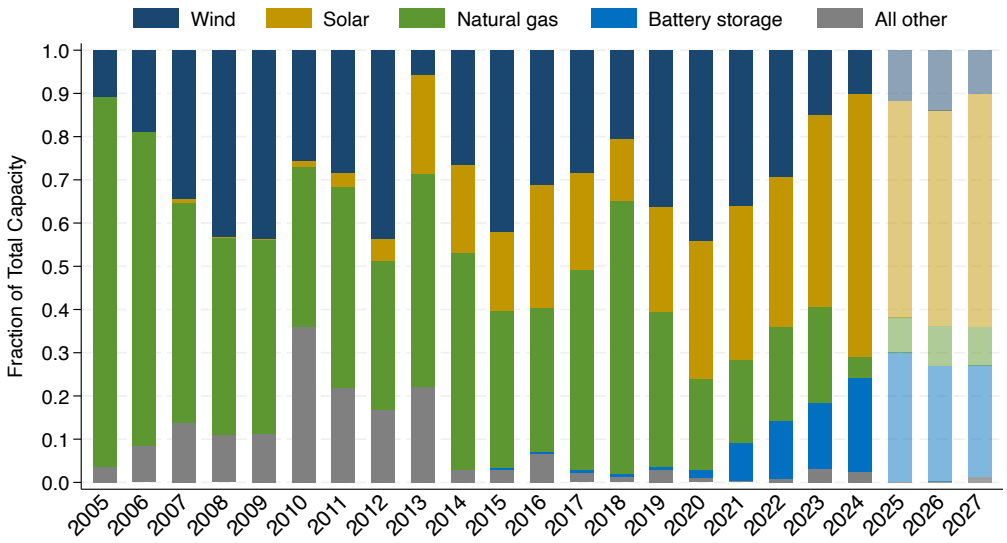
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Tables and Figures

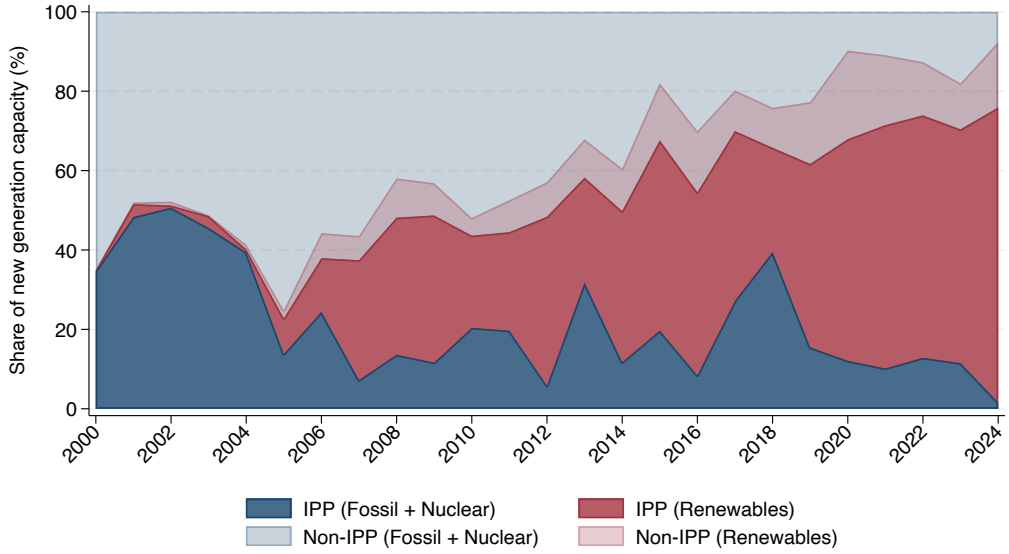
Figures

Figure 1: Share of new U.S. electricity generation capacity additions by technology



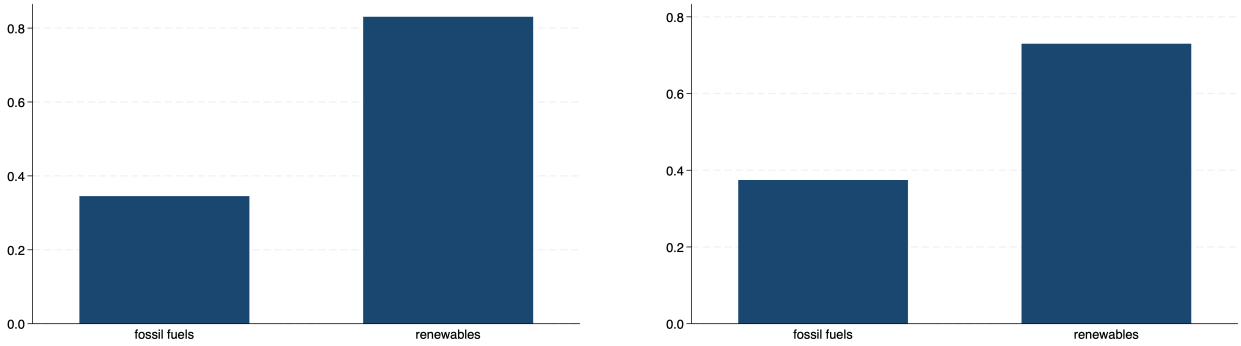
Notes: This figure shows the annual share of new U.S. utility-scale electricity generation capacity additions by technology from 2005 to 2027. Data for 2025–2027 reflect planned (proposed) projects. Data from the U.S. Energy Information Administration (EIA).

Figure 2: Share of new generation capacity financed by IPPs



Notes: This figure shows the annual share of new U.S. utility-scale electricity generation capacity additions financed by independent power producers (IPPs) and non-IPPs, by technology and fuel type, from 2000 to 2024. Data from the U.S. Energy Information Administration (EIA).

Figure 3: Comparison of installed generation capacity financed by IPPs and LLCs.

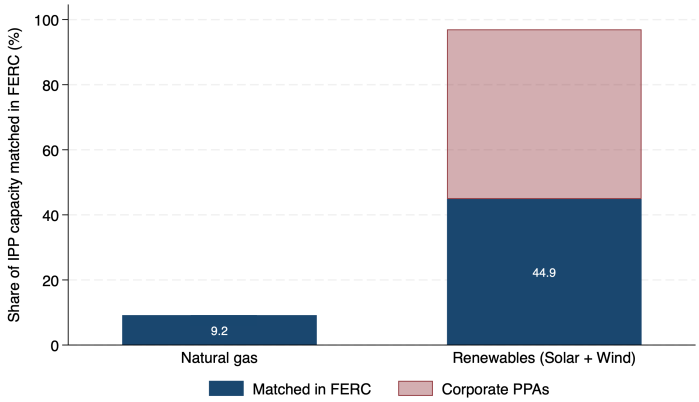


(a) Independent Power Producers (IPPs)

(b) Limited Liability Companies (LLCs)

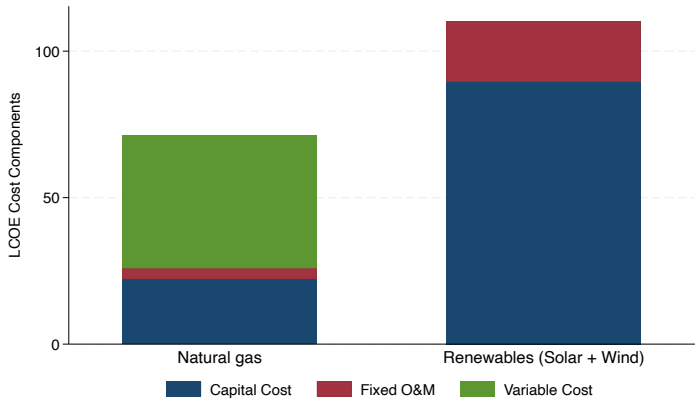
Notes: The figure reports the shares of installed generation capacity in 2024 financed by Independent Power Producers (IPPs) and Limited Liability Companies (LLCs), respectively. Each panel shows the share of capacity (in MW) aggregated into fossil fuels (natural gas, coal and petroleum) and renewables (solar and wind). Nuclear and other renewables are excluded. Data from the U.S. Energy Information Administration (EIA).

Figure 4: Share of IPP capacity that can be matched to regulatory filings of utility PPAs



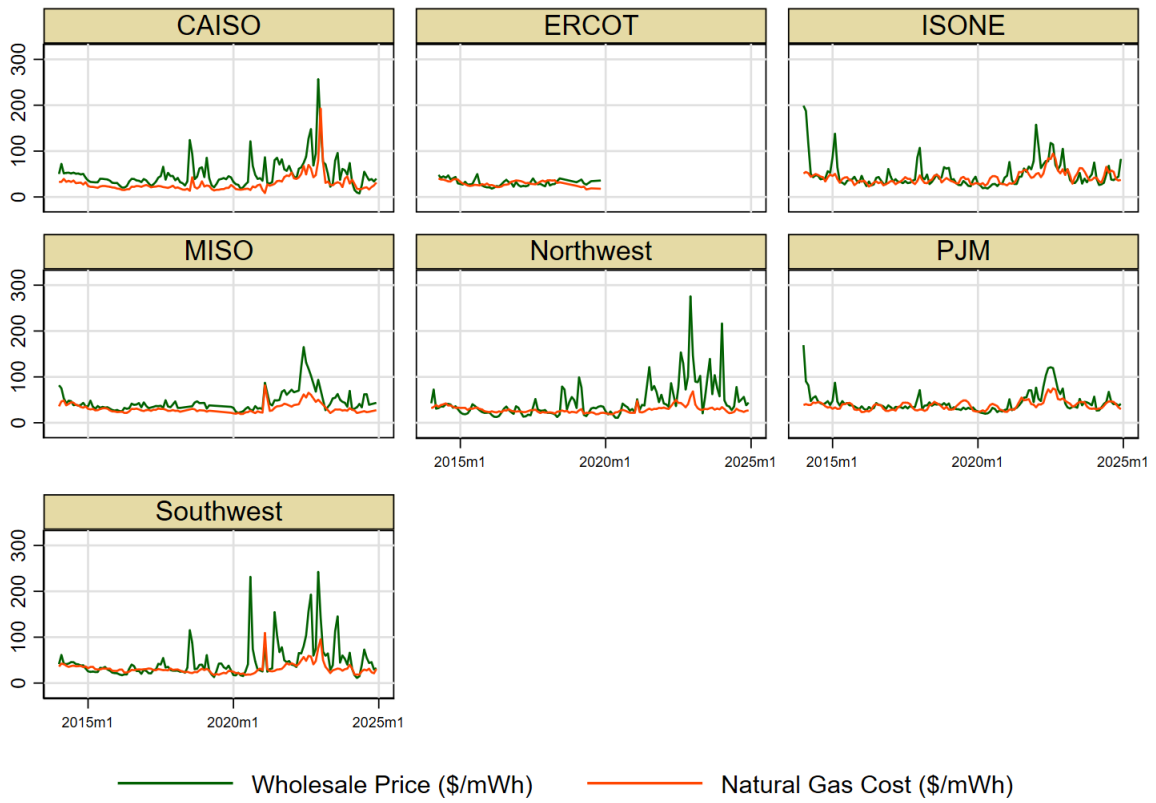
Notes: This figure shows the share of independent power producer (IPP) capacity for natural gas and renewables (onshore wind, offshore wind, and solar) reported in the *EIA-860* data that can be matched to utility power purchase agreements (PPAs) in the Federal Energy Regulatory Commission (FERC) database. The sample includes plants operable since 2015 and excludes ERCOT, which is outside FERC jurisdiction. The blue bars represent the fraction of IPP capacity matched to FERC-filed *utility* PPAs, while the red bars indicate *corporate* renewable PPAs reported by Bloomberg New Energy Finance (BNEF) since 2015.

Figure 5: Breakdown of LCOE across technologies



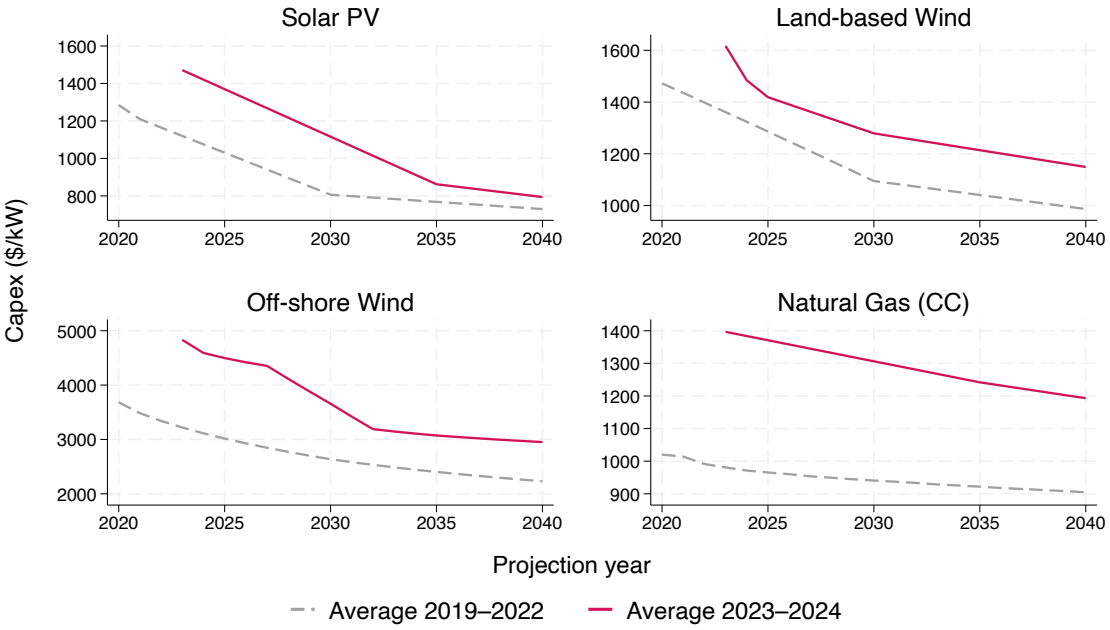
Notes: The figure shows the decomposition of the levelized cost of electricity (LCOE) into capital, fixed operation and maintenance (O&M), and variable cost components for natural gas and renewable technologies. Renewable technologies include onshore and offshore wind and solar. The height of each bar represents the average total LCOE, and segments indicate the relative contribution of each cost component. Data from the U.S. Energy Information Administration (EIA), covering annual estimates from 2014 to 2023.

Figure 6: Wholesale prices and natural gas input costs by ISO



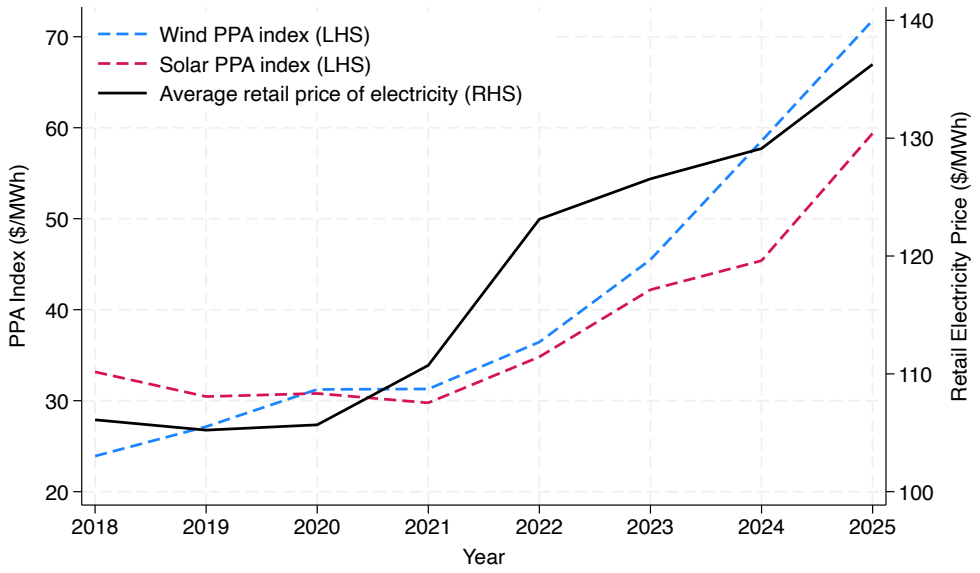
Notes: This figure shows average wholesale price and natural gas by ISO. Wholesale prices are obtained from the EIA, and natural gas costs are calculated as the product of the EIA's citygate gas price and an assumed heat rate of 7000 BTU/kWh.

Figure 7: CAPEX forecasts over time across technologies



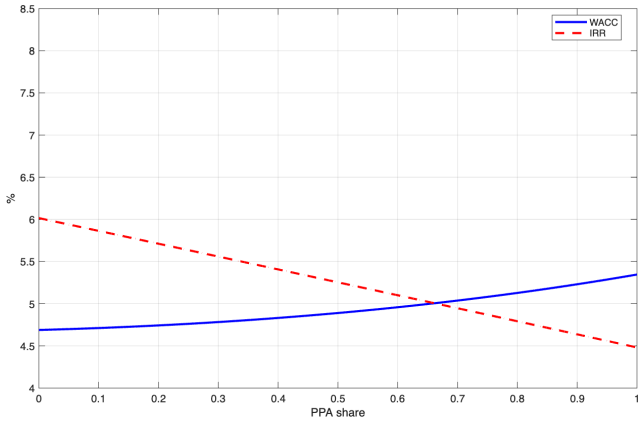
Notes: This figure shows capital expenditure projections for different generation technologies over time from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) *Reference* scenario. The red line shows the average projections from the 2023–2024 ATB editions and the grey dashed line shows the average projections from the 2019–2022 ATB editions. For each technology, we use the representative plant configuration as defined by NREL.

Figure 8: PPA versus retail electricity prices

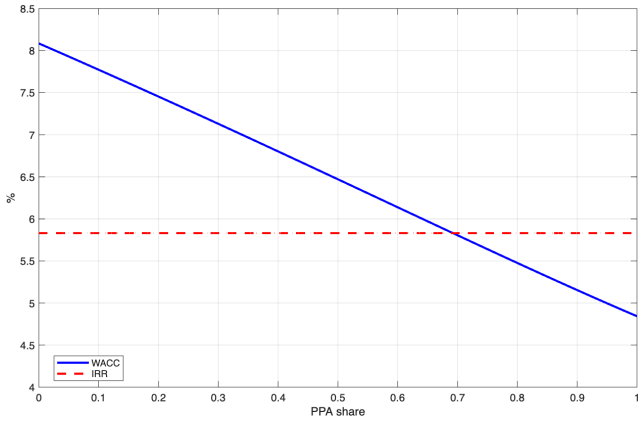


Notes: This figure compares solar and wind PPA price indices (left axis) with the average U.S. retail electricity price (right axis). Separate indices for wind and solar are constructed as an annual equal-weighted average of the LevelTen Energy (corporate) PPA price index and annual averages of utility PPA prices collected by the Berkeley Lab. LevelTen indices reflect the 25th percentile of observed U.S. PPA prices, capturing the most competitive market offers. The solid black line reports the average retail electricity price from the U.S. Energy Information Administration (EIA). The sample covers 2018Q3 to 2024Q3. All series are expressed in nominal dollars per MWh.

Figure 9: Model-implied effect of power purchase agreements (PPA) on IRRs and cost of capital for different technologies.



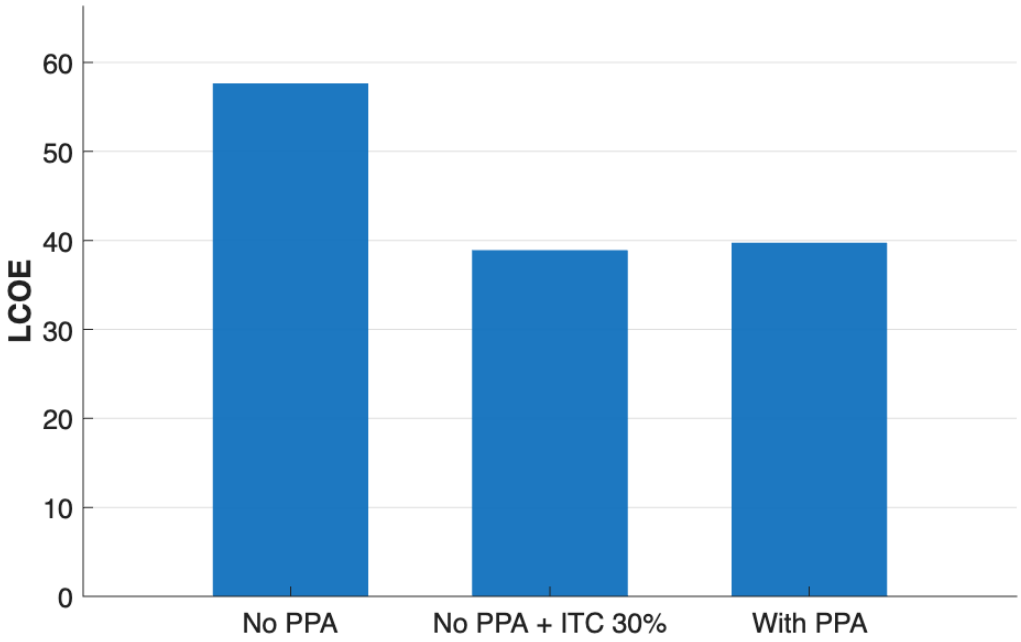
(a) Gas



(b) Solar

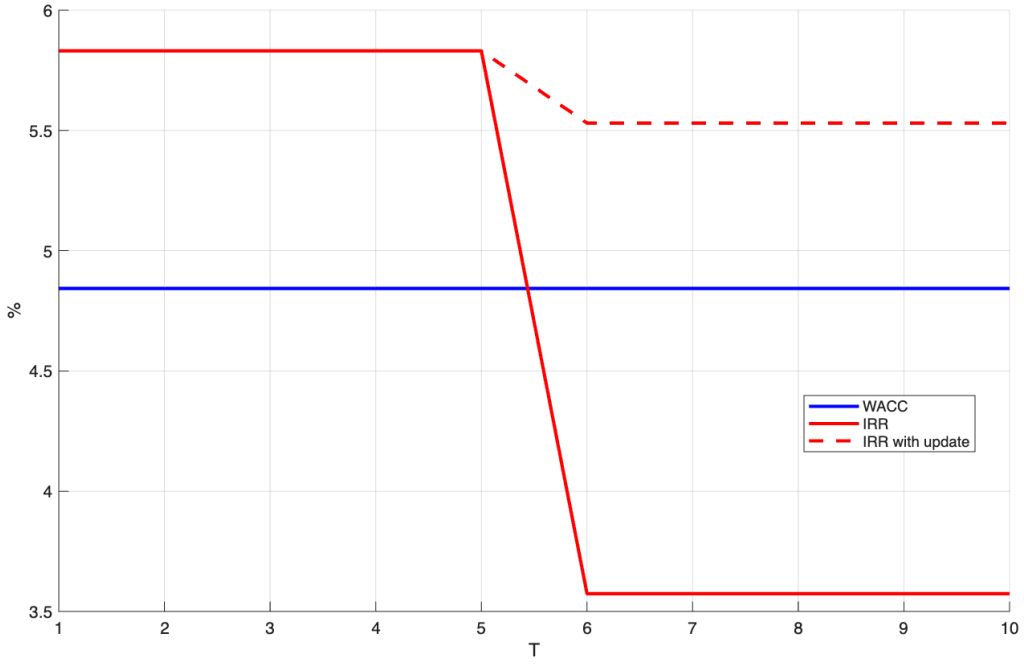
Notes: This figures shows the model-implied effect of the usage of PPAs on the IRR of a gas project (Panel A) and a solar project (Panel B). The x-axis is the share of the project revenues contracted under a PPA. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The details of the parameter calibration and model as are discussed in the text.

Figure 10: LCOE and PPA



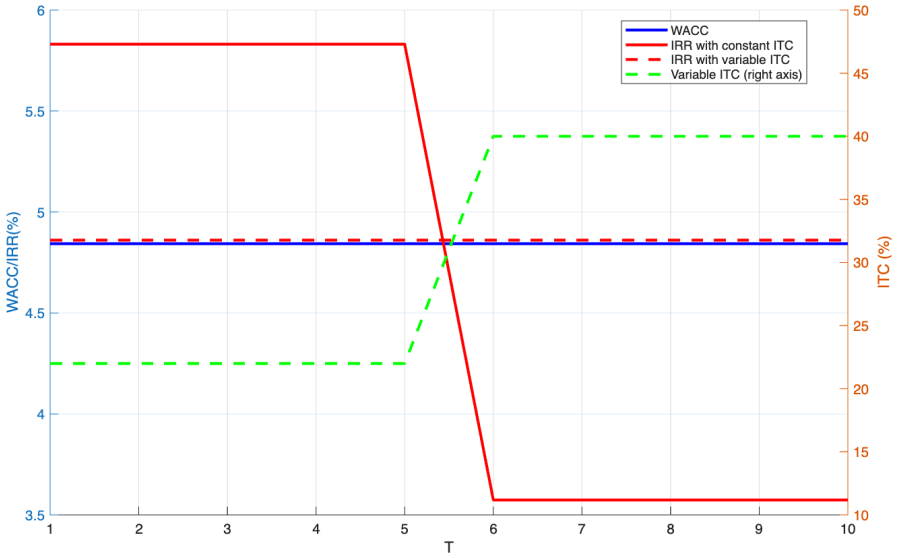
Notes: This figure shows the model-implied the levelized cost of energy (LCOE) for a solar project under three scenarios. The LCOE is defined as the constant electricity price such that the NPV of the project is zero. The left bar assumes no PPA and no investment tax credit (ITC), the middle bar assumes no PPA and an ITC of 30%, and the right bar assumes a PPA and no ITC. The details of the parameter calibration and model as are discussed in the text.

Figure 11: Model implied effects of a cost shock on project IRRs and cost of capital



Notes: This figure show the model-implied dynamics of the internal rate of return (IRR) of a renewable project around a cost shock at $T = 6$. The x-axis indexes time periods. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The solid red line assume a PPA price that is constant over time. The dashed red line assumes a PPA prices that increases at $T = 6$ by the same amount as the cost shock. The details of the parameter calibration and model as are discussed in the text.

Figure 12: Model-implied effect of time-varying subsidies on project IRRs and cost of capital.



Notes: This figure show the impact of time-varying subsidies in our baseline model on a renewable project. There is a cost shock at $T = 6$. The x-axis indexes time periods. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The solid red line assume an investment tax credit that is constant over time at 30%. The dashed red line assumes an investment tax credit that is 25% before the cost shock and 42% after. The dashed green line shows the value of the investment tax credit over time. The details of the parameter calibration and model as are discussed in the text.

Tables

Table 1: Flexibility of electricity generation across technologies

	ln(net generation)						
	Baseload	Gas Baseload	Gas Mid	Gas Peaker	Other Renewables	Solar	Wind
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ln(wholesale price)	0.146**	0.269*	0.271**	0.707***	-0.0843	0.0165	-0.0624
	(0.0397)	(0.132)	(0.107)	(0.166)	(0.0592)	(0.136)	(0.0498)
Constant	15.22***	14.47***	13.14***	10.90***	14.83***	12.22***	14.24***
	(0.147)	(0.487)	(0.396)	(0.613)	(0.218)	(0.500)	(0.184)
Observations	757	757	757	757	757	757	757
Adjusted R^2	0.976	0.863	0.719	0.904	0.960	0.873	0.914
IsoFE	Y	Y	Y	Y	Y	Y	Y
YearFE	Y	Y	Y	Y	Y	Y	Y

Notes: The dependent variable is the natural logarithm of monthly net electricity generation by technology and ISO. The explanatory variable is the natural logarithm of the average monthly wholesale electricity price in the same ISO. Columns report separate regressions for baseload generation (coal and nuclear), natural gas generation disaggregated by operational role (baseload, mid-merit, and peaker), other renewables (biomass, hydro, and geothermal), utility-scale solar, and wind. All regressions include ISO and year fixed effects. Standard errors, clustered at the ISO level, are reported in parentheses. The sample covers the contiguous United States from 2000 to 2024. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 2: Summary Statistics of Electricity Prices and Natural Gas Costs by ISO

Statistic	ISO Region							
	CAISO	ERCOT	ISONE	MISO	Northwest	PJM	Southwest	Average
Mean:								
(1) Wholesale price (p_t)	49.76	31.21	49.42	45.69	46.53	44.28	47.02	44.84
(2) Natural Gas Cost (c_t)	28.71	29.81	41.61	31.06	28.64	37.59	31.69	32.73
(3) Spark spread ($p_t - c_t$)	21.05	1.40	7.81	14.64	17.89	6.69	15.33	12.11
SD:								
(4) Wholesale price	31.05	7.70	30.37	23.28	38.47	22.29	38.65	27.40
(5) Natural Gas Cost	19.01	5.88	12.86	10.29	7.66	10.02	12.59	11.19
(6) Spark spread mwh	24.55	8.36	26.52	16.43	34.56	18.30	34.52	23.32
Variance:								
(7) Wholesale price	963.96	59.29	922.23	541.73	1480.12	497.02	1493.50	851.12
(8) Natural Gas Cost	361.44	34.57	165.51	105.87	58.72	100.39	158.54	140.72
(9) Spark Spread	602.53	69.85	703.06	269.95	1194.42	334.83	1191.76	623.77
(10) Variance ratio	0.60	0.49	0.24	0.39	0.05	0.30	0.13	0.31
(11) cov(p_t, c_t)	361.44	12.01	192.34	188.82	172.21	131.29	230.14	184.04
(12) Implied correlation(p_t, c_t)	0.61	0.27	0.49	0.79	0.58	0.59	0.47	0.54

Notes: This table reports summary statistics for the mean, standard deviation (SD) and variance for the wholesale electricity price p_t (\$/mWh), natural gas input cos c_t (\$/mWh), and spark spread which is the wholesale price minus the natural gas cost ($p_t - c_t$). We calculate these summary statistics by ISO region. The variance ratio in row 10 is defined as the $Var(c_t)/Var(p_t - c_t)$. The implied correlation in row 12 can be obtained as: $\rho_{p,c} = \frac{Var[p_t]+Var[c_t]-Var[p_t-c_t]}{2\times\sqrt{Var[p_t]Var[c_t]}}$. Wholesale electricity prices are obtained from the EIA and natural gas prices refer to citygate prices, also obtained from the EIA. Data spans 2014-2024.

Table 3: Wholesale electricity prices and macroeconomic variables

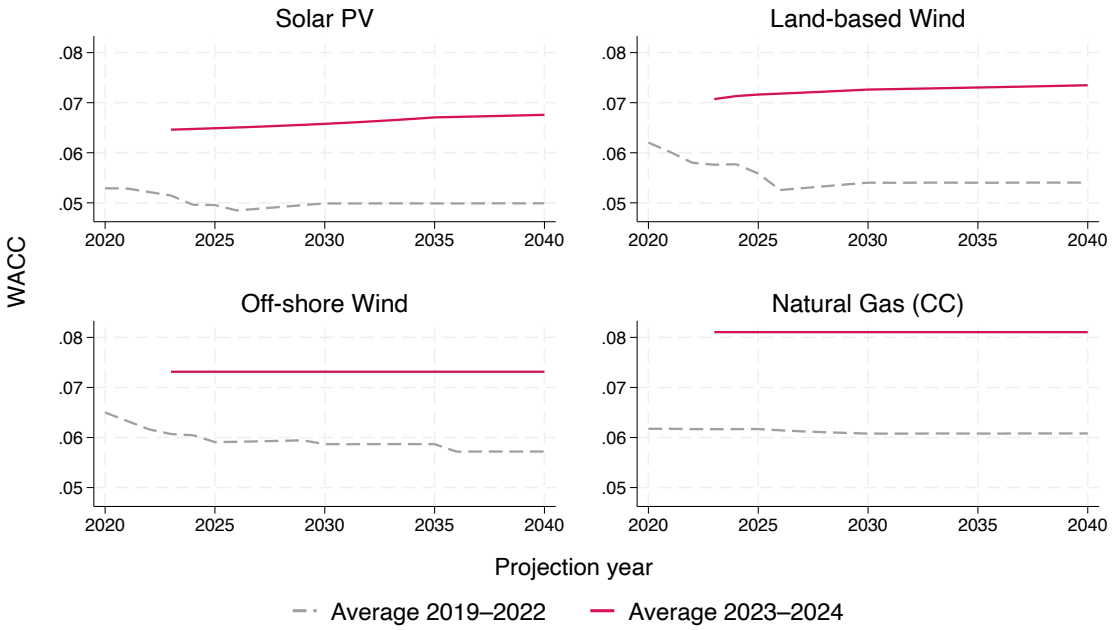
	Wholesale Electricity Price (YOY %)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Core CPI (YoY %)	12.26***					12.01***	
	(3.877)					(4.044)	
Core PCE (YOY %)		20.81***					20.91***
		(4.244)					(4.545)
Excess Market Return			-0.252	-0.195		-0.0244	0.0831
			(0.782)	(0.822)		(0.739)	(0.701)
SMB			-1.370	-1.379		-1.283	-1.171
			(1.177)	(1.184)		(1.248)	(1.150)
HML			1.575	1.142		1.140	0.643
			(1.546)	(1.951)		(1.564)	(1.477)
RMW				-0.209		-0.910	-1.190
				(1.913)		(1.823)	(1.670)
CMA				1.233		1.102	0.890
				(2.511)		(3.614)	(3.601)
Investment Factor					1.967	-1.780	-1.551
					(2.805)	(4.407)	(4.208)
Constant	-14.92	-27.52**	20.82*	20.69*	19.65*	-13.67	-28.00**
	(13.47)	(11.66)	(11.30)	(11.37)	(11.32)	(13.85)	(12.04)
N	276	276	276	276	276	276	276
adj. R^2	0.063	0.148	0.002	-0.004	0.002	0.048	0.133
controls	Y	Y	Y	Y	Y	Y	Y

Notes: This table reports regressions of the year-over-year percentage change in wholesale electricity prices on key macroeconomic indicators. The dependent variable is the annualized growth rate of volume-weighted average U.S. wholesale electricity prices. Explanatory variables include core CPI inflation (YoY %), core PCE inflation (YoY %), Fama-French 3-factor and 5-factor monthly returns, and the investment theme factor return from Jensen et al. (2023). Control variables for the 10-year Treasury yield and the federal funds rate are included where indicated. Each column presents a separate regression with the variables indicated. Heteroskedasticity-robust standard errors are reported in parentheses. The sample period is from 2000 to 2024. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

INTERNET APPENDIX

IA.1 Additional figures

Figure IA.1: WACC forecast over time across technologies



Notes: This figure shows cost of capital projections for different generation technologies over time from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) *Reference* scenario. The red line shows the average projections from the 2023–2024 ATB editions and the grey dashed line shows the average projections from the 2019–2022 ATB editions. For each technology, we use the representative plant configuration as defined by NREL.

IA.2 Full model of macro-risk

Persistence of shocks: This mechanism exists if there is persistence in electricity prices and input costs. Assume that the aggregate shock s_t displays some level of persistence:

$$s_t = \rho s_{t-1} + e_{s,t}$$

with $\rho < 1$ and $Var[e_{s,t}] = \sigma_s^2$. The long-run (unconditional) mean of s_t is 0, but $E[s_t|s_0] = \rho^t s_0$. If the current state is $s_0 = 0$, $E[s_t|s_0] = 0 \quad \forall t$. However, the variance increases with the time horizon: $Var[s_t|s_0] = \sigma_s^2 \frac{1-\rho^{2t}}{1-\rho^2}$.

Project development and construction: Assume that at $t = 0$ the project PPA is signed (if any). Construction is done at $t = \tau$ at the unit cost i_τ and operations start the following year. The parameter τ captures the development time (permitting, studies, etc.) that can vary across technologies (for instance longer for wind than solar). The depreciation rate of capacity K is δ. For simplicity, we first consider a project with fixed capacity factor θ. What is the (per-unit) NPV of the project when construction starts at $t = \tau$?

$$NPV_\tau/K = \sum_{n=1}^{\infty} \frac{(1-\delta)^{n-1}\theta E[p_{\tau+n} - c_{\tau+n}|s_\tau]}{(1+r)^n} - i_\tau$$

To capture macro variation, we assume that investment cost are pro-cyclical: $i_\tau = \bar{i} + a^i s_\tau$. Because of persistence, high cost today implies higher electricity prices in the future. This is a natural hedge that is undermined by a PPA. Formally, $E[p_{\tau+n} - c_{\tau+n}|s_\tau] = \rho^n s_\tau$. The NPV at $t = \tau$ simplifies to:

$$NPV_\tau/K = \underbrace{\frac{\theta(\bar{p} - \bar{c})}{r+\delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho(a_p - a_c)\theta}{r+1-\rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

There is now risk that comes from the loading on s_τ (the state of the world when con-

struction starts).[38] The variance of the NPV is given by:

$$\left[\frac{\rho(a_p - a_c)\theta}{r+1-\rho(1-\delta)} - a^i\right]^2 Var[s_\tau|s_0]$$

The beta with the aggregate state s_τ is similarly given by: $\left[\frac{\rho(a_p-a_c)\theta}{r+1-\rho(1-\delta)} - a^i\right]$.

Everything equal, a PPA ($a^p = 0$) increases macro risk as long as $a^i > 0$. (Here were are ignoring the fact that a PPA might change r.) However, if macro variation in investment cost are ignored ($\hat{a}^i \approx 0$), then a PPA can actually reduce risk through the usual operational cash-flow channel (as long as a_c is low enough).

Macro risk also increases with development horizon τ, since $Var[s_\tau] = \sigma_s^2 \frac{1-\rho^{2\tau}}{1-\rho^2}$ and $\rho < 1$.

The same force exists when production is flexible (i.e. ξ is not necessarily zero). In this case the (per-unit) NPV is given by:

$$NPV_\tau/K = \underbrace{\frac{\theta(\bar{p}-\bar{c}) + \xi\mathcal{V}}{r+\delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho(a_p-a_c)(\theta+\xi(\bar{p}-\bar{c}))}{r+1-\rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

where $\mathcal{V}$ captures the variance of future profit margins, with $\mathcal{V} \approx \sigma_p^2 + \sigma_c^2 + (a_p - a_c)\sigma_s^2/(1-\rho^2)$.[39] The previous insight that setting $\xi = 0$ hurts baseline NPV is also visible here.

What if there is time-to-build? This is straightforward to include in the model. If it takes $\tau' \geq 1$ periods to build, the effect weakens. Intuitively, if it took forever to build, electricity prices would drift back to their long-run level and would be uncorrelated with construction costs irrespective of PPA. That means that the downside of PPA does not comes from time-to-build but from "time-to-develop".

Formally,

$$NPV_\tau/K = \underbrace{\frac{\theta(\bar{p}-\bar{c}) + \xi\mathcal{V}}{r+\delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho^{\tau'}(a_p-a_c)(\theta+\xi(\bar{p}-\bar{c}))}{r+1-\rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

[38] The expected NPV is close to the baseline as long as $s_0 \approx 0$.

[39] This ignores a small correction for increasing variance of s_t over time. The exact last term is $(a_p - a_c)\sigma_s^2/(1-\rho^2)[1-\rho^2(r+\delta)/(r+1-\rho(1-\delta))]$.

As $\tau' \to \infty$, the first term of macro risk vanishes and cyclicality only comes from investment costs.