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TAX POLICY AND POWER SECTOR DECARBONIZATION

Joseph Aldy, Jun Gao, and Kenneth T. Gillingham

Aldy is affiliated with Harvard Kennedy School, NBER, Resources for the Future, and Center for Strategic and International Studies; Gao with Harvard University; and Gillingham with Yale University, ifo Institute, and NBER. This paper was written for the Brookings Institution-University of Utah conference on "The Forces Shaping America's Fiscal Future" in June 2026. The Brookings Institution and the Salata Institute for Climate and Sustainability at Harvard University provided financial support for this research. The authors are grateful for valuable comments on a previous version of this manuscript by Bill Gale and Elena Patel, as well as participants of the authors' virtual conference and "The Forces Shaping America's Fiscal Future" conference.

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Abstract

Over the past three decades, U.S. tax policy has provided an array of tax expenditures, such as production tax credits, investment tax credits, and accelerated depreciation, to promote the deployment of clean energy technologies in the electric power sector. In conjunction with non-tax subsidies (such as loan guarantees, grants in lieu of tax credits, state and local policies) and regulations (for example, state Renewable Portfolio Standards), public policy has enabled cost-reducing innovation and significant adoption of zero-carbon power generation technologies. With most scenarios for deep decarbonization of the U.S. energy economy relying on a combination of power sector decarbonization and broad electrification of energy services (such as mobility and heating), this paper focuses on the evolution of tax policy and renewable power technologies to draw insights and lessons for future policy design. We show how the vast majority of the costs of new investment in renewable power technologies reflect "soft costs," some of which arise from regulatory barriers related to permitting, siting, and connecting to the transmission system. We identify options for improving the cost-effectiveness of targeting the carbon externality through clean power tax credit design as well as regulatory reforms that could reduce these shadow costs, both of which could accelerate clean energy deployment.

I. Introduction

In principle, addressing the risks of a changing climate through the tax code could generate substantial fiscal revenue. Many economists, policy advocates, and even some members of Congress, have advocated for a tax on carbon dioxide emissions to deliver the dual benefits of mitigating climate change and raising revenues. In practice, however, federal tax expenditures[1] have become an increasingly important instrument for promoting clean energy investment in the United States. What began as relatively modest incentives has evolved into policies with significant revenue implications, making their effectiveness and cost-effectiveness increasingly important questions for both climate policy and the nation's fiscal future. This paper reviews and analyzes the role of tax policy in power sector decarbonization, drawing insights from the evolution of clean energy tax policy and renewable power technologies to assess the effectiveness, economic efficiency, and cost-effectiveness of these tax expenditures, as well as their interaction with regulatory and related barriers to clean energy deployment.

Over the past three decades in the electric power sector, tax laws have designed production tax credits, investment tax credits, and accelerated depreciation to promote the deployment of renewable sources of electricity and related clean energy technologies. In conjunction with non-tax subsidies (such as loan guarantees, grants in lieu of tax credits, state and local policies) and regulations (for example, state Renewable Portfolio Standards[2]), public policy has contributed to cost-reducing innovation and significant adoption of zero-carbon power generation technologies. As these policies expanded, so

[1] A tax expenditure is revenue forgone because a provision of the tax code—such as a credit, deduction, exemption, preferential rate, or deferral—deviates from the benchmark tax system.
[2] Renewable Portfolio Standards are state policies requiring electric utilities or other electricity suppliers to obtain a specified share of the electricity they sell from eligible renewable sources, such as wind and solar power.

too did their fiscal significance. While characterized by significant uncertainties, the potential tax expenditures of the Inflation Reduction Act of 2022, for example, could have exceeded $1 trillion over 10 years before its modification in the One Big Beautiful Bill Act (OBBBA) of 2025 (Aldy 2025). Research suggests that the Inflation Reduction Act contains large inframarginal transfers to emission reduction that would occur anyways and is less efficient than an equivalent carbon price, and while it spurred investment, it would have likely fallen well short of delivering on U.S. net-zero goals by 2050 (Bistline et al. 2023).

To the extent that tax policy plays a role in addressing climate change going forward, it will most likely do so through the power sector. Given the evolution of technologies in the power sector and among end-use energy consuming activities, deep decarbonization in the U.S. energy economy will reflect both decarbonization of the power sector and electrification of energy services. To reach net-zero greenhouse gas emissions by 2050, the share of electricity in final energy is predicted to increase to between 20% and 56% in 2050 compared with 18% to 25% in 2020 (Gao et al. 2025). Electrification of transportation, which accounts for 29% of U.S. emissions (U.S. Environmental Protection Agency 2026b), will contribute to substantial new electricity demand in the decades to come. Nearly all light-duty vehicles will be electric by 2050 among a larger set of energy-economic modeling results (Kerry and McCarthy 2021; Bistline 2021). In the building sector, heat pumps, electric heaters and electric cooking will continue to replace pipeline gas and electrified heating is predicted to exceed 60% of new sales by 2030 and nearly 100% by 2050. The share of building-sector final energy supplied by electricity rises from about 50% in 2020 to 90% or more by 2050, dramatically changing the overall energy system.

Taken together, these shifts imply a power sector that must become both substantially larger and substantially cleaner. According to the U.S. Energy Information Administration's Annual Energy Outlook 2026, total U.S. electricity generation could increase by 25% to 50% by 2050 (U.S. Energy Information Administration 2026b), while installed generating capacity could rise by 50% to 90% from its current level of approximately 1,300 gigawatts (GW) (U.S. Energy Information Administration 2026e; 2026a). Renewable sources account for 48% of projected capacity additions in the Counterfactual Baseline case and 60% in the Low Zero-Carbon Technology Cost case (U.S. Energy Information Administration 2026a). As the share of electricity generated from solar and wind increases from approximately 18% today to 40% in the Counterfactual Baseline case, and as coal-fired power plants—which accounted for 17% of U.S. electricity generation in 2025—gradually retire, the carbon dioxide emissions intensity of the U.S. power sector is expected to decline substantially (U.S. Energy Information Administration 2026c; 2026a). Although generation and capacity projections vary considerably across models and remain subject to substantial uncertainty, their overall direction is unambiguous: decarbonizing the energy economy will require building a great deal of new clean generating capacity—and doing so quickly.

Electrification is not the only force pushing electricity demand upward, and the other major driver owes nothing to climate policy. The build-out of data centers used for generative artificial intelligence (AI) and other purposes is already spurring substantial increases in electricity consumption. Annual U.S. electricity use reached a new high in 2025 and will grow further through 2026 and 2027 (U.S. Energy Information Administration 2026b). This demand occurs whether or not new clean capacity keeps pace with it. In the near term, it will raise prices, spur generation from existing power plants, and encourage new capacity

investment—of whatever type can be built quickest. It will also put further strain on the electricity grid, potentially exacerbating reliability concerns absent considerable investments to improve power system reliability. Demand growth of this kind thus raises the stakes for the tax policies and regulatory processes that determine how quickly new generation, clean or otherwise, can come online.

In our work, we assess how policymakers have employed the tax system to influence the adoption of clean electricity generation. The investment in new, clean power generating capacity occurs within a networked energy system characterized by market failures and regulatory constraints. We focus on the evolution of tax policy relating to clean electricity and what it means for the economics of clean electricity. Indeed, the past few decades have exhibited dramatic shifts in technologies, costs, policies, and the associated tax expenditures of these policies.

While tax policy has influenced the shifts we have seen in the electricity system, it has only highly imperfectly targeted pollution. Subsidizing clean electricity is at best a second-best substitute for the first-best, Pigouvian[3] approach of taxing the polluting activity at the level of the damages it imposes on society. A subsidy rewards the entry of qualifying new sources rather than the emissions of incumbents, and it pushes the price of electricity down rather than up. Moreover, even conditional on subsidizing clean electricity, credits that pay the same amount regardless of what generation a project displaces may be poorly targeted. That lowers cost-effectiveness (in other words, raises costs per ton abated) and thus increases the tax expenditure required to reach any given climate goal. We develop this comparison against a carbon tax benchmark below.

Tax policy also does not operate in isolation. Clean energy tax credits interact with the other policies and regulatory frameworks governing the power system—state Renewable Portfolio Standards, any price on carbon, and the non-tax subsidies that often stack on the same project—sometimes reinforcing them and sometimes rendering them irrelevant at the margin. Current regulatory institutions impose a further set of frictions on renewable power development: the interconnection queue (the queue formed by potential generators that wish to connect to the electricity grid), facility siting and permitting barriers, imperfect competition, and suboptimal reliability standards and requirements each impose shadow costs or hidden costs that slow clean energy adoption and that tax credits can offset only indirectly. Reforms reducing these barriers would be expected to interact with subsidies or a carbon tax to increase clean energy adoption, and we take up both the interactions and the reforms below.

The next section highlights the evolution of the costs and deployment of renewable power technologies, with a focus on the role of tax policy and related subsidies. The subsequent section explores the various ways in which clean energy tax credits in practice fall short of efficiently targeting the carbon dioxide externality[4]. We then conclude with an assessment

[3] A Pigouvian tax, named after British economist Arthur Pigou, discourages socially harmful activities—such as pollution—by requiring those responsible to bear the costs they impose on others.
[4] An externality is a cost or benefit imposed on third parties who are not directly involved in producing or consuming a good or service. Here, the externality is the harm caused by carbon dioxide emissions that is not reflected in market prices.

of policy reforms in both tax policy and in the regulatory landscape that governs renewable power deployment.

II. Evolution of tax policy and renewable power technologies over time

In this section, we discuss the relevant policy, technological, and economic landscape for renewable power in the United States. We cover the primary tax policy instruments that have been used to spur renewable power investment and production. We further characterize how tax expenditures per megawatt (MW) of capacity and per megawatt-hour (MWh) of production have evolved, with variation in both policy design and project capital costs. Finally, we synthesize the relevant literature on how policy has contributed to innovation and cost reductions, and we compare and contrast the key attributes of current renewable technologies with current fossil fuel technologies.

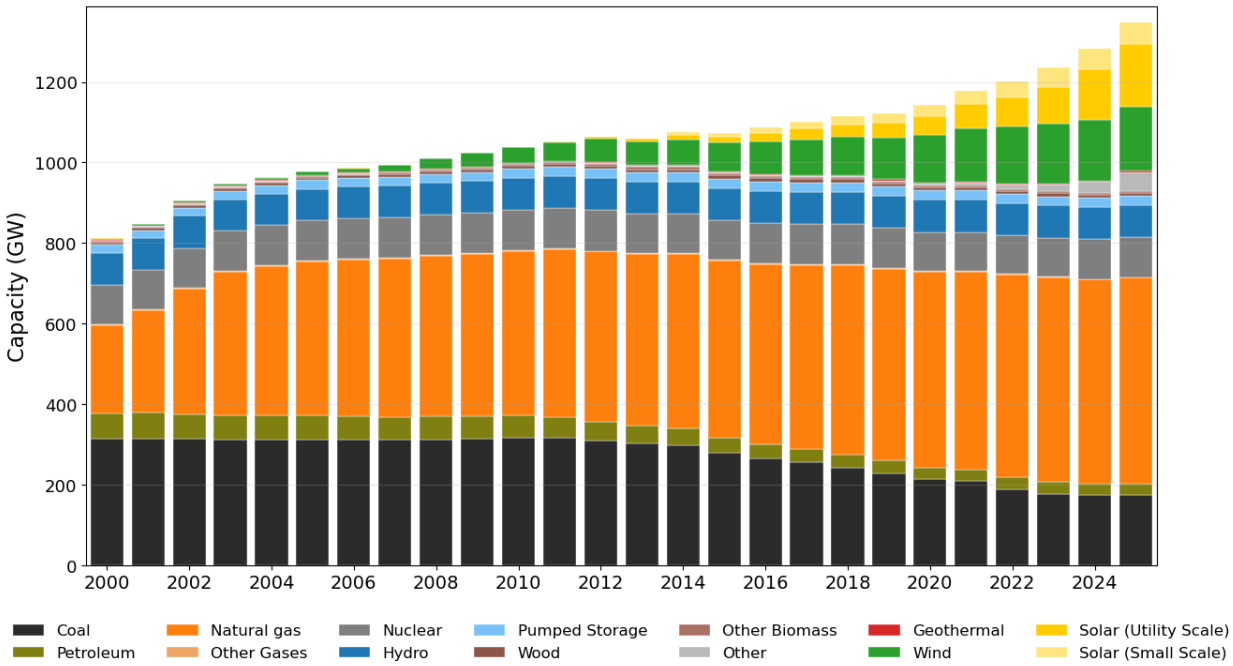
A. Major trends

Four trends have reshaped the U.S. power sector over the past quarter century. Generating capacity has grown by roughly two-thirds, with wind and solar accounting for essentially all net additions since 2010. The costs of these technologies have fallen dramatically, so much so that solar and wind are now cheaper per MWh than coal or natural gas. Technology has improved as well, though the gains show up unevenly in realized output. Larger turbines have raised wind capacity factors, while, for solar, advances such as tracking and bifacial panels have been largely offset by the move to lower-quality sites, leaving capacity factors roughly flat. And these shifts have unfolded alongside federal tax subsidies at considerable scale, on the order of $10 billion to $20 billion annually over the past decade. We take each in turn.

The U.S. electric power sector capacity increased from about 800 GW to more than 1,300 GW between 2000 and 2025 (see Figure 1). During this period, coal capacity fell almost in half, as natural gas capacity increased.

FIGURE 1

U.S. electric power sector net summer capacity, by technology, 2000–2025 (gigawatts)



Data source: EIA form 860 and form 861. See Appendix B for detailed data sources and processing.

In addition, the U.S. power sector has realized a considerable and steady increase in renewables, starting with wind power in the mid-2000s and followed by solar power in the mid-2010s. By 2025, wind reached 160 GW and solar reached 209 GW, with 156 GW of utility-scale solar and 53 GW of small-scale residential and commercial solar. It is worth noting that capacity does not directly translate into generation, as renewable generators can have much lower capacity factors (in other words, the ratio of a plant's actual output to its maximum potential output) than natural gas or coal plants designed to operate for extended periods. The average capacity factor for solar power plants is about 25% and for wind power about 35% (U.S. Energy Information Administration 2019; 2022). Much of the wind generation tends to be at night when wholesale electricity prices are usually lower. In some regions, large solar generation can cause low power prices in the afternoon.

The cost of renewable energy technology has fallen dramatically since 2000 (Figure 2). The top panel of Figure 2 shows the overall installed cost and the module price for residential solar. Declining module prices have been the primary driver, with the residual costs (balance-of-system costs and soft costs including permitting, installation labor, interconnection, overhead, profit margin) falling at a slower pace. Some of the decline in module prices reflects innovation induced by deployment subsidies like investment tax credits (Gerarden 2023). In 2022, module prices represented slightly more than 10% of installed costs of residential solar projects.

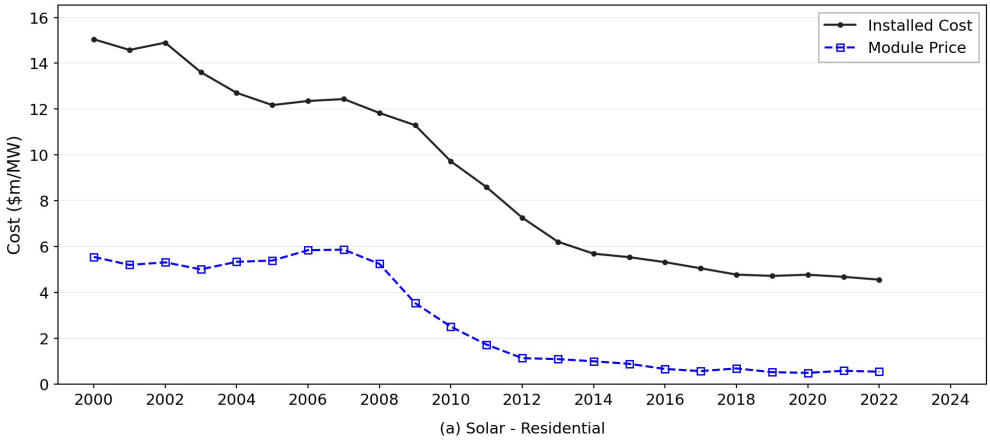
The middle panel of Figure 2 shows cost trends in utility-scale solar, which largely mirror the trends in residential solar. The installed costs of utility-scale solar are significantly lower

than residential solar and are very close to onshore wind (middle and bottom panels of Figure 2). In 2022, module prices represented only about 20% of installed costs of utility-scale solar projects.

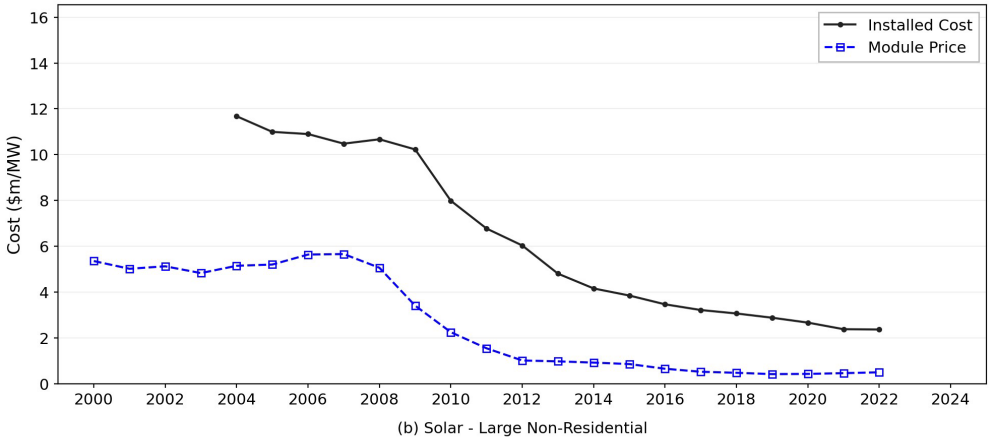
The bottom panel of Figure 2 shows that the trend in onshore wind costs differs significantly from solar. The largest decrease in wind power costs happened in the 1980s and 1990s. By 2000, onshore wind had already become quite cheap and since 2000 the installed cost has been rather stable, despite wind turbine prices falling by half during the past two decades.

FIGURE 2

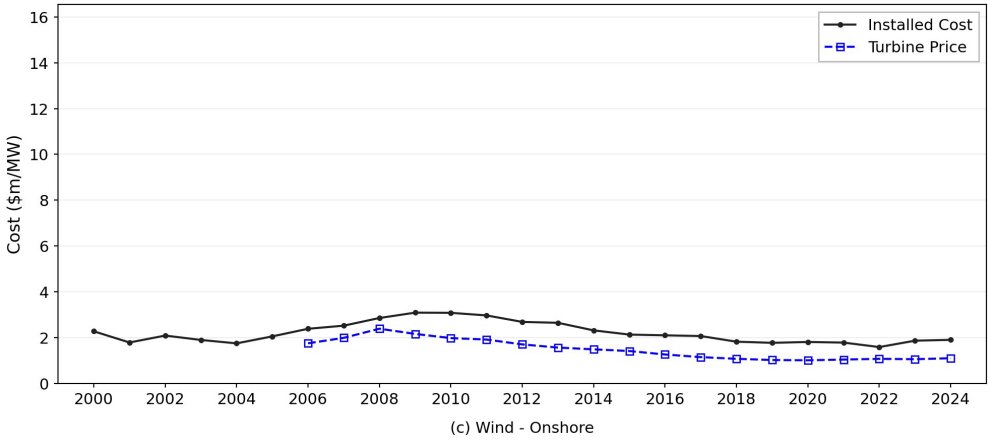
Prices for solar and wind power, by installed project capacity and by module/turbine, 2000–2024 (millions of 2025$/megawatt)



(a) Solar - Residential



(b) Solar - Large Non-Residential



(c) Wind - Onshore

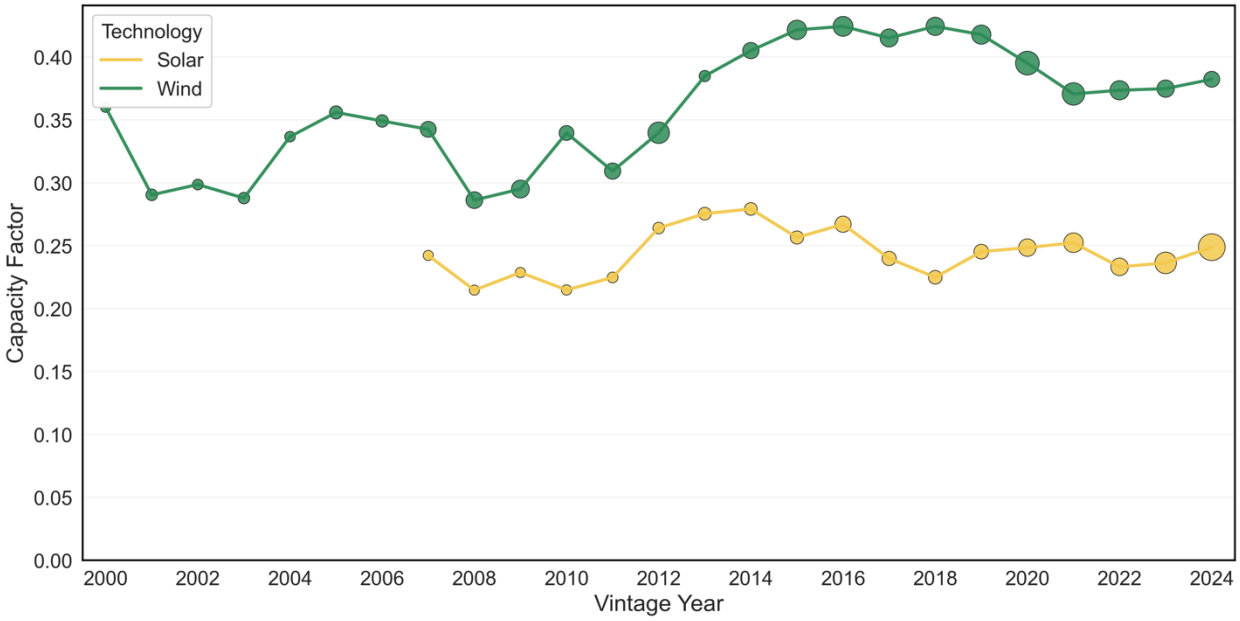
Notes: 1. Data source: Lawrence Berkeley National Lab. See Appendix B for detailed data sources and processing. 2. Values are in 2025 dollars. 3. For solar in panel (a) and (b): Installed Price (solid line) is median total installed system cost per MW, covering hardware (modules, inverters, racking) plus balance-of-system and soft costs (permitting, installation labor, interconnection, overhead, profit margin); Module Price (dashed line) is module-only price component, isolated from the total. For wind in panel (c): Installed Price (solid line) is

capacity-weighted average total installed cost per MW, covering turbine supply, civil/electrical balance-of-plant, and soft costs; Turbine Price (dashed line) is turbine-only transaction price per MW (nacelle, tower, blades).

The capacity factors for wind and solar facilities determine the commercial viability of the technologies. Wind technology capacity factors have increased over the past several decades, while solar capacity factors have oscillated in the 20% to 25% range (Figure 3). While a growing number of wind projects have located at sites with lower-quality wind resources than earlier-vintage facilities, the significantly larger wind turbine designs enable them to use wind resources more effectively, as can be seen in the lower panel of Figure 4, which decomposes the capacity factor determinants. Solar technologies' capacity factors have improved more modestly. Improvements in technology, such as tracking and bifacial panels, have been largely offset by decreasing site quality in terms of solar potential (see the upper panel of Figure 4).

FIGURE 3

Capacity factor for solar and wind power technology by vintage year

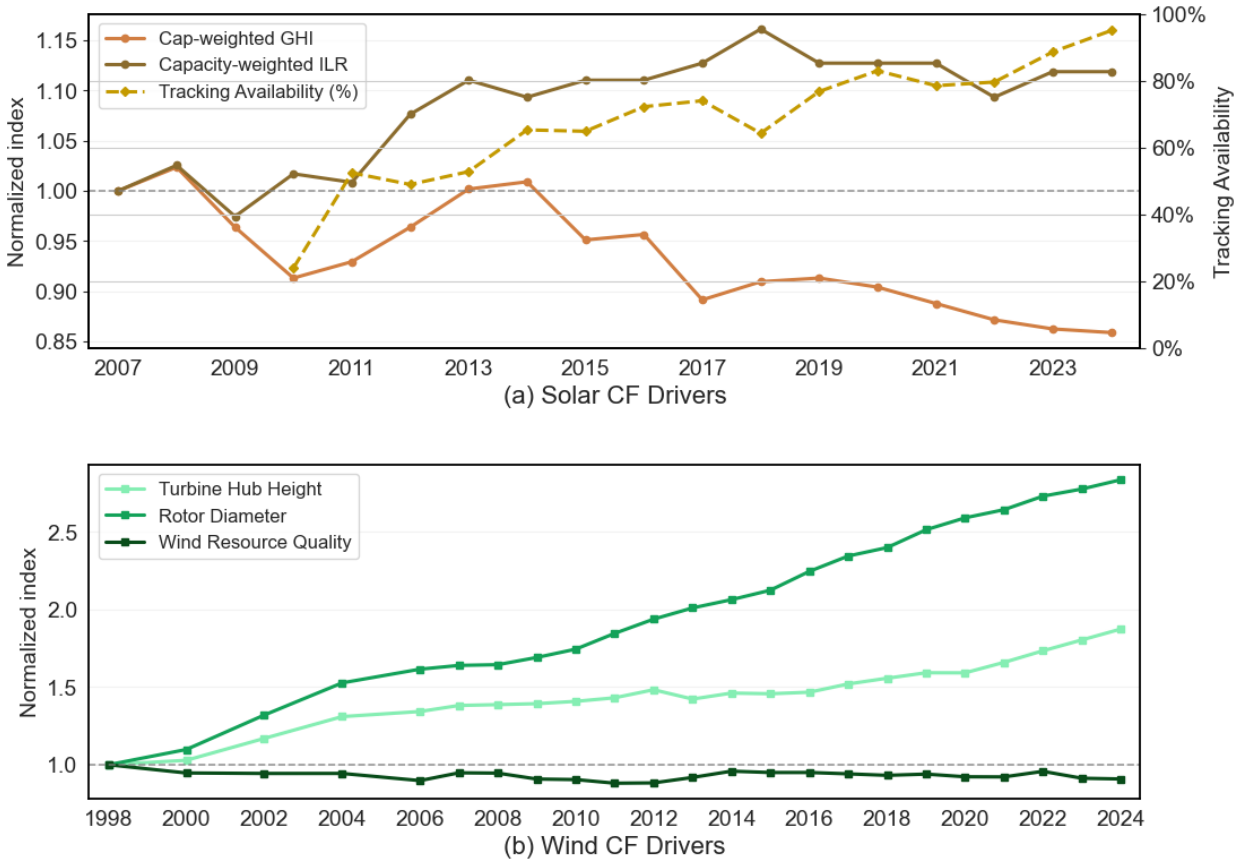


Notes: 1. Capacity factor is capacity-weighted for projects of vintage year t in year t+1. 2. The size of the dots indicates total generation (MWh) by each vintage in their first full year. 3. These are the capacity factors for the first full year of operation of the technology. 4.

Data source: EIA Form 860 and Form 906/920/923.

FIGURE 4

Capacity factor drivers for solar power and wind power



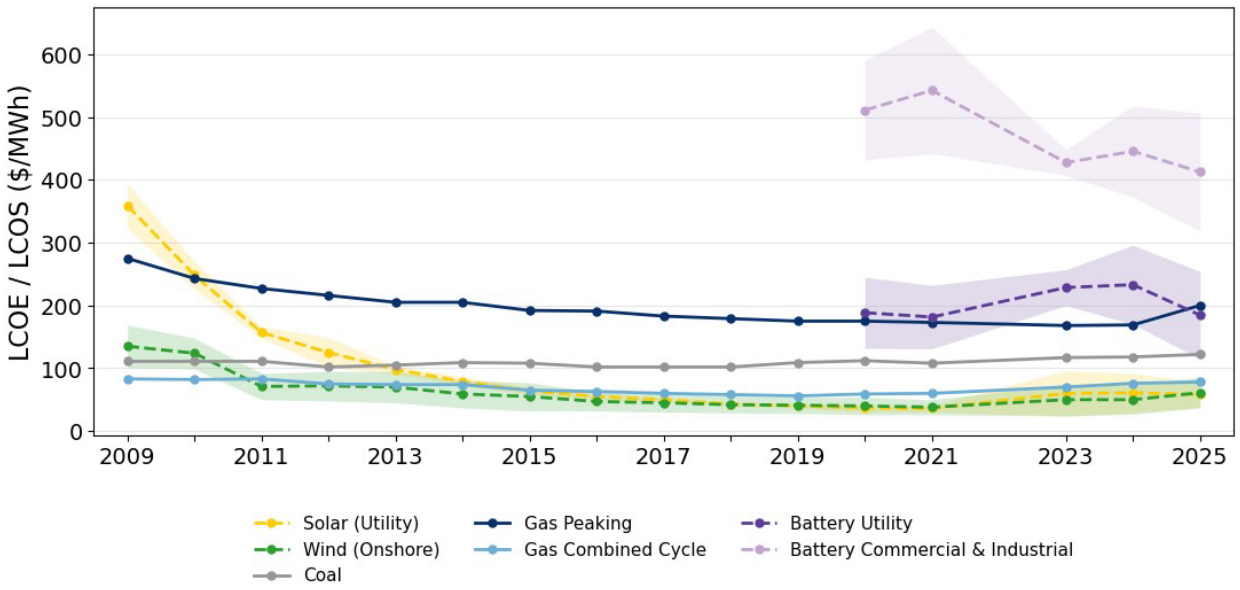
Notes: 1. Data source: LBNL. 2025 Utility-Scale Solar Data Update and Land-Based Wind Energy Technology Update 2025 Edition. 2. GHI stands for Global Horizontal Irradiance, which measures the sunlight for solar power generation, in other words, "solar potential"; ILR stands for Inverter Loading Ratio—a higher ratio allows a smaller inverter to serve more solar panels, effectively reducing inverter and thus overall system costs. 3. The indices are calculated by normalizing the earliest year for each technology, that is, 2007 for solar and 1998 for wind, as 1. Tracking availability is plotted as raw data since it started from very low value and has quadrupled.

The levelized cost of electricity (LCOE) represents the average cost per unit of generation accounting for initial investment costs and variable costs associated with operations and maintenance and, in the case of some power plants, the price of fuel. This enables a comparison among various technologies, although it should be noted that additional attributes of power plants, such as the flexibility to respond to high-value, high-demand periods and to ensure the reliability of the grid, are not reflected in the LCOE measure. Through a series of annual reports dating over the past two decades, Lazard shows that the LCOE values for solar and wind power have fallen below those for fossil fuel generation (Figure 5). Pairing battery storage with renewable power plants could enable more flexible, reliable power although at costs that are still on average higher than coal-fired power or combined-cycle gas-fired power plants. Battery-storage systems appear to be on par with peaking natural gas plants—that is, plants used primarily during periods of peak electricity demand (such as, hot summer afternoons and early evenings). The recent growth in battery

storage in Texas illustrates the potential for batteries to leverage solar to meet peak demand.

FIGURE 5

Levelized cost of electricity, by technology, 2009–2025 (2025$/MWh)



Notes: 1. Data source: Lazard, "Levelized Cost of Energy Analysis". All values already expressed in 2025 U.S dollars. 2. The shades for solar and wind indicate the high and low end of estimated LCOE and dashed lines indicate the average. For gas (peaking), gas (combined cycle) and coal, solid lines show average estimates.

B. Theoretical foundations and practical policies

The cost and productivity trends documented above did not emerge from private markets alone, and there is a strong theoretical foundation for the policy support that accompanied them. Environmental externalities motivate tax-like pricing, while knowledge spillovers and research and development externalities (Romer 1990; Aghion and Howitt 1996; Howitt and Aghion 1998) motivate subsidies for clean research and development—a channel that bears directly on the cost declines in Figures 2 and 5, since a firm that lowers the cost of solar modules or wind turbines captures only part of the resulting benefit. These factors also make the innovation path dependent (Acemoglu et al. 2012; Aghion et al. 2019): The direction of technical change today shapes what is cheap to build decades later, so both the timing and the durability of policy are consequential. The existence of other market failures such as financing frictions and coordination problems also can justify policy intervention in clean technology (Armitage et al. 2024).

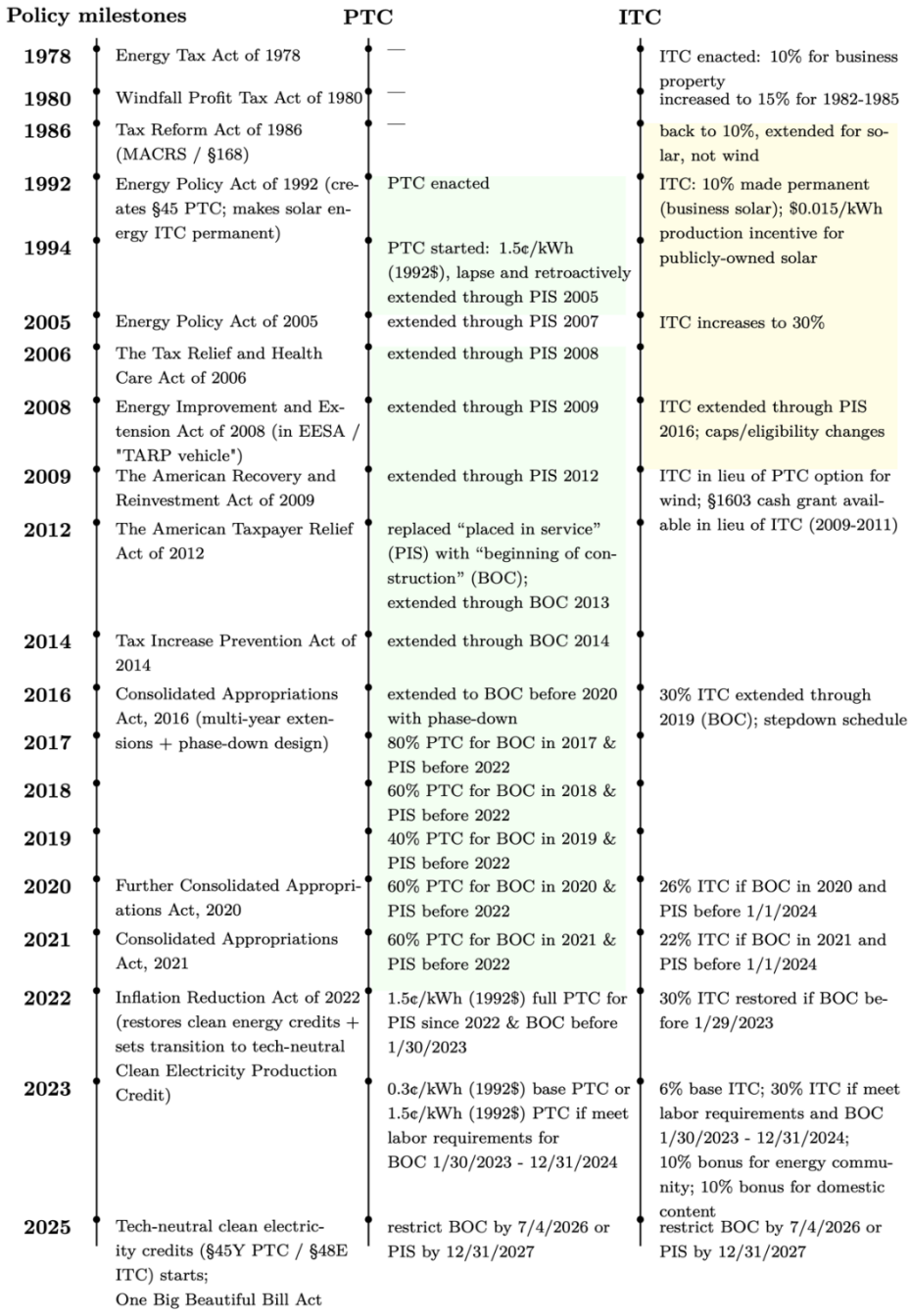
This multiplicity of market failures carries an implication for how we assess the instruments used. Because no single instrument addresses emissions externalities, knowledge spillovers, financing frictions, and coordination problems at once, a portfolio of policies is likely to be more cost-effective than any single instrument (Fischer and Newell 2008). The carbon tax benchmark we develop in the next section is therefore not an argument that

subsidies have no role; it is a way of isolating how well the tax credits adopted target the one externality—carbon dioxide emissions—that they are most often defended as addressing. Whether these theoretical channels have in fact operated in U.S. renewable power markets is a separate empirical question, and one on which the U.S.-specific evidence is considerably thinner than the theory. We return to it at the end of this section.

In practice, a range of policy instruments have been deployed to shape clean technology markets, including carbon pricing and other pricing instruments, tax credits, direct subsidies, loan guarantees and grants, as well as fuel standards and other command-and-control regulations (Aldy et al. 2022). Tax-related policies, including production tax credits (PTC) and investment tax credits (ITC), have been the most salient renewable energy policies in the United States. Figure 6 presents the timeline of the PTC and ITC.

FIGURE 6

Timeline of Internal Revenue Code provisions subsidizing renewable power, 1978–2025



	Policy milestones	PTC	ITC
1978	Energy Tax Act of 1978	—	ITC enacted: 10% for business property
1980	Windfall Profit Tax Act of 1980	—	increased to 15% for 1982-1985
1986	Tax Reform Act of 1986 (MACRS / §168)	—	back to 10%, extended for solar, not wind
1992	Energy Policy Act of 1992 (creates §45 PTC; makes solar energy ITC permanent)	PTC enacted	ITC: 10% made permanent (business solar); $0.015/kWh production incentive for publicly-owned solar
1994		PTC started: 1.5¢/kWh (1992$), lapse and retroactively extended through PIS 2005	
2005	Energy Policy Act of 2005	extended through PIS 2007	ITC increases to 30%
2006	The Tax Relief and Health Care Act of 2006	extended through PIS 2008	
2008	Energy Improvement and Extension Act of 2008 (in EESA / "TARP vehicle")	extended through PIS 2009	ITC extended through PIS 2016; caps/eligibility changes
2009	The American Recovery and Reinvestment Act of 2009	extended through PIS 2012	ITC in lieu of PTC option for wind; §1603 cash grant available in lieu of ITC (2009-2011)
2012	The American Taxpayer Relief Act of 2012	replaced "placed in service" (PIS) with "beginning of construction" (BOC); extended through BOC 2013	
2014	Tax Increase Prevention Act of 2014	extended through BOC 2014	
2016	Consolidated Appropriations Act, 2016 (multi-year extensions + phase-down design)	extended to BOC before 2020 with phase-down	30% ITC extended through 2019 (BOC); stepdown schedule
2017		80% PTC for BOC in 2017 & PIS before 2022	
2018		60% PTC for BOC in 2018 & PIS before 2022	
2019		40% PTC for BOC in 2019 & PIS before 2022	
2020	Further Consolidated Appropriations Act, 2020	60% PTC for BOC in 2020 & PIS before 2022	26% ITC if BOC in 2020 and PIS before 1/1/2024
2021	Consolidated Appropriations Act, 2021	60% PTC for BOC in 2021 & PIS before 2022	22% ITC if BOC in 2021 and PIS before 1/1/2024
2022	Inflation Reduction Act of 2022 (restores clean energy credits + sets transition to tech-neutral Clean Electricity Production Credit)	1.5¢/kWh (1992$) full PTC for PIS since 2022 & BOC before 1/30/2023	30% ITC restored if BOC before 1/29/2023
2023		0.3¢/kWh (1992$) base PTC or 1.5¢/kWh (1992$) PTC if meet labor requirements for BOC 1/30/2023 - 12/31/2024	6% base ITC; 30% ITC if meet labor requirements and BOC 1/30/2023 - 12/31/2024; 10% bonus for energy community; 10% bonus for domestic content
2025	Tech-neutral clean electricity credits (§45Y PTC / §48E ITC) starts; One Big Beautiful Bill Act	restrict BOC by 7/4/2026 or PIS by 12/31/2027	restrict BOC by 7/4/2026 or PIS by 12/31/2027

Notes: 1. The green shade indicates credits applicable to wind but not solar and the yellow shade indicates solar but not wind. Both instruments have been available to other technologies including geothermal from time to time. 2.Explicit credit values in the figure are for facilities with capacity >1~MW. Higher rates have been available for smaller facilities.

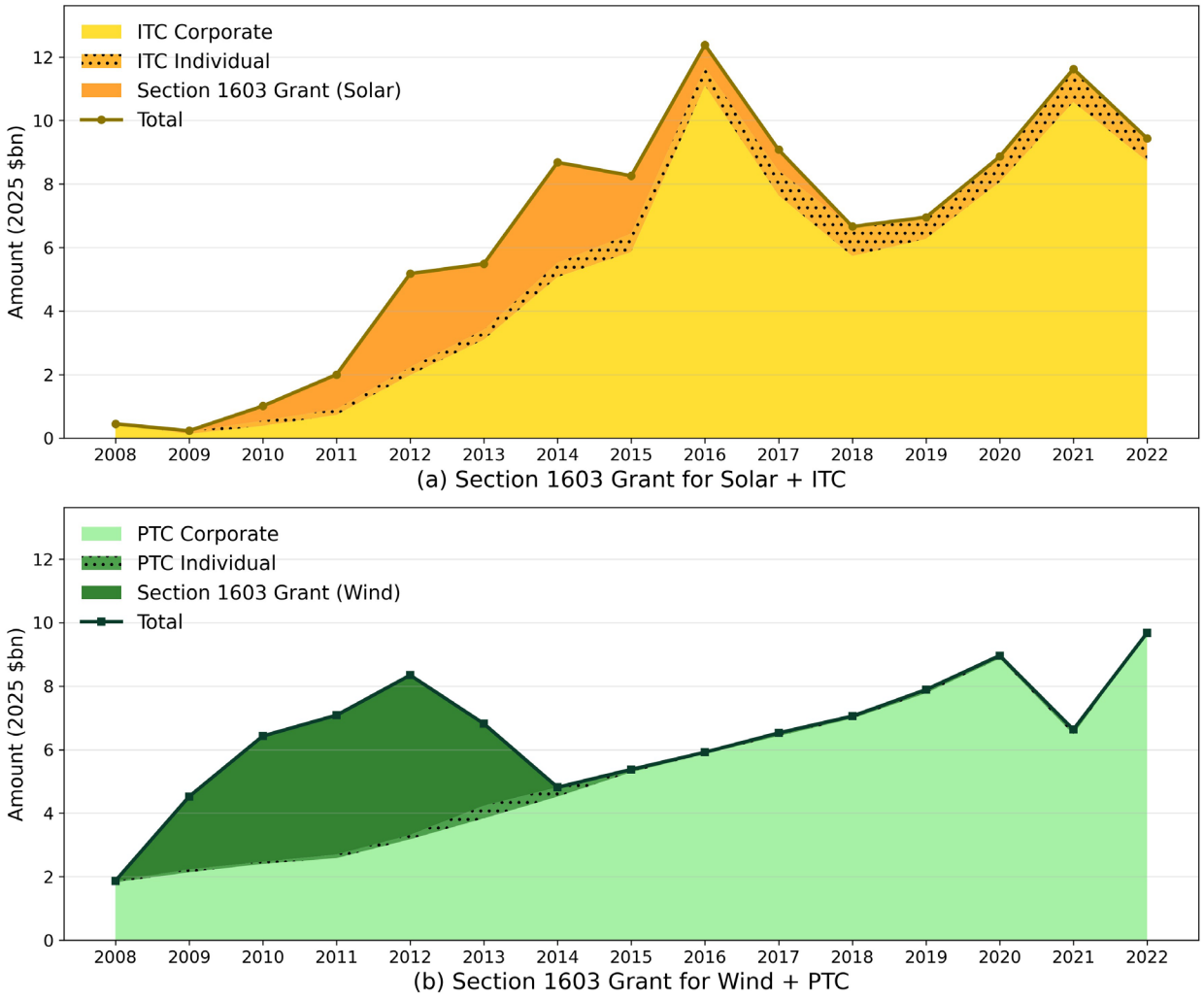
The evolution of clean energy tax policy depicted in Figure 6 has translated into significant tax expenditures through both the ITC and PTC since 2008 (Figure 7), as well as the

Section 1603 grant that renewable developers could claim in lieu of the ITC or PTC under the American Recovery and Reinvestment Act of 2009. The claims have been on the order of $10 billion to $20 billion annually over the past decade, reflecting significant policy-driven cycles. The large increase in Section 1603 grant expenditures for wind farms in 2012 reflected the requirement that wind farm claimants must have been placed into service by December 31, 2012 to receive the grant. The booms in solar ITC claims in 2016 and 2021 predated two policy changes—the step-down in the ITC after 2016 and the prospect of ITC expiration after 2021.

The falling technology costs described above (Figures 2 and 5) enable greater deployment, as evident in Figure 1. With a PTC, growing capacity investment and associated generation increases tax expenditures. With an ITC, there are countervailing forces—growing capacity would, all else equal, increase tax expenditures, but falling investment costs per unit capacity could offset this effect (Aldy 2025). The experience with the Section 1603 grant illustrates the appeal of allowing project developers to receive subsidies directly, without having to partner with outside investors that could use the projects' tax credits. Many solar and wind developers therefore opted for the 1603 grant (Aldy 2013). This informed the Inflation Reduction Act provisions that enable developers to transfer their tax credits, which reduces the transaction costs of monetizing the value of tax credits (Aldy 2025). The downside risk, however, of offering an investment grant (Section 1603) is that the selection of an investment subsidy caused wind farms to produce less power than if they had selected a production subsidy (Aldy et al. 2023).

FIGURE 7

Federal tax expenditures for PTC and ITC, 2008–2022



Notes: 1. Data sources: IRS Corporation Income Tax Returns Line Item Estimates, IRS Individual Income Tax Returns Line Item Estimates (ITC/PTC) and U.S. Treasury Section 1603 grant awards. See Appendix B for detailed data sources and processing. 2. ITC includes a small amount on geothermal (2009–2016). ITC claims for wind are not included here because they are not consistently reported and, when available, are of a much smaller scale than solar. 3. PTC includes a small amount on refined coal/steel/Indian coal.

C. Case studies showing the impact of subsidies

A complete assessment of subsidies for clean energy must account for non-tax code policies that reduce the cost or increase the revenues for renewable power projects in addition to tax expenditures. To illustrate the extensive bundle of implicit and explicit subsidies, Table 1 summarizes the key economics of Agua Caliente, which was the largest U.S. solar power facility when it was placed into service in 2011 (Panel A) and Shepherds Flat, which was the largest wind farm in the country when it was placed into service in 2012 (Panel B). Agua Caliente is a 290-megawatt photovoltaic solar project in Arizona that cost

approximately $1.8 billion to build. The project received about $840 million in subsidies, roughly 47% of its investment costs, through the ITC, accelerated depreciation, a Department of Energy loan guarantee, and a price premium in its long-term power purchase agreement for selling qualifying renewable power into California under its Renewable Portfolio Standard. Shepherds Flat is an 845-megawatt wind farm in Oregon that also sells power into California under its Renewable Portfolio Standard. The project's $1.9 billion investment costs were offset by nearly 60% through the Section 1603 grant in lieu of tax credit, accelerated depreciation, loan guarantee, power purchase agreement price premium, and state tax credits. In both cases, and in many other utility-scale renewable power projects, the tax code delivers substantial subsidies, and these are generously complemented by other subsidy programs.

TABLE 1

Illustrative renewable energy projects

(a) Solar: Agua Caliente

Category	Component	Present Value at Aug-2011 Close ($m)
Cost		
	Land-acquisition	12
	Site-preparation	54
	Module	918
	Inverter	144
	Labor	252
	Other qualified cost	171
	Residual cost ineligible for ITC	248
Total Cost		1800
Subsidy		
	Investment Tax Credit	465
	Accelerated depreciation	173
	DOE loan guarantee	113
	RPS/PPA premium (California)	89
Total Subsidy		840

(b) Wind: Shepherds Flat

Category	Component	Present Value at 2012 Close ($m)
Cost		
	GE turbine + service contract	1400
	Other qualified-cost	238
	Residual cost ineligible for grant basis	262
Total Cost		1900
Subsidy		
	1603 cash grant	492

	Accelerated depreciation	138
	DOE loan guarantee	152
	State subsidies (Oregon)	123
	RPS/PPA premium (California)	220
Total Subsidy		1125

Note: See Appendix B for assumptions and calculations.

D. Empirical evidence of fiscal instruments' clean energy impacts

A growing empirical literature evaluates whether, and through which channels, policies can stimulate clean technology innovation, accelerate cost reduction, and increase adoption. Given limited U.S.-based evidence, we draw on evidence from clean technology markets worldwide. This global perspective helps identify the mechanisms through which policy affects innovation, learning-by-doing, and deployment, while still examining the implications for U.S. policymaking.

On the innovation side, some of the strongest evidence comes from pricing-type instruments. Using patent data from the auto industry across 80 countries, Aghion et al. (2016) show that higher fuel prices redirect innovation away from dirty technologies and toward clean ones, with strong path dependence in the direction of technical change. Similarly, Popp (2002) finds that higher energy prices in the United States during 1970–1994 induced more energy-efficient innovation. In the European context, Calel and Dechezleprêtre (2016) show that the introduction of the European Union Emissions Trading System increased low-carbon patenting among regulated firms by about 10 percent without crowding out innovation in other technological areas. Beyond pricing instruments, policy-induced market expansion can also stimulate innovation: Fu et al. (2018) find that both state tax incentives and Renewable Portfolio Standards promoted wind innovation in the United States, although financial incentives tended to have more local effects while standards generated broader spillovers. Relatedly, Banares-Sanchez et al. (2024) show that Chinese solar industrial policies increased solar photovoltaics (PV) output, innovation, and productivity, with especially large effects when production subsidies were paired with research and development support. The most effective policy may vary among technologies (Johnstone et al. 2010).

A second strand of the literature focuses more directly on cost reduction through learning-by-doing (that is, cumulative experience in producing or installing a product will lower costs) and policy-induced improvements in technology quality. Bollinger and Gillingham (2023) estimate modest learning-by-doing and learning spillovers across firms in the non-technology soft costs of installing solar in California. Gerarden (2023) shows that consumer subsidies not only increased solar adoption but also stimulated producer solar panel innovation, improved conversion efficiency, and reduced production costs, with important international spillovers. Similarly, Barwick et al. (2025) highlight the role of consumer electric vehicle (EV) subsidies in accelerating cost declines in EV batteries through learning-by-doing. More broadly, this literature suggests that policies should not be evaluated solely on static measures of cost-effectiveness, because their long-run value

may depend on how much they accelerate cumulative production, learning, and future cost declines (Gillingham and Stock 2018).

A third strand emphasizes adoption and the design of deployment incentives. De Groote and Verboven (2019) study residential solar photovoltaic (PV) in Belgium from 2006 to 2012 and show that generous production subsidies triggered very large adoption responses, but that households heavily discounted future subsidy streams[5], implying that equivalent upfront subsidies could have achieved similar adoption at lower cost. Bollinger et al. (2025) find a similar result using data from California but go further and show that the discounting of future subsidy streams differs across wealth groups, with lower-wealth households discounting the streams at a much higher rate than higher-wealth households. This illustrates that policy design matters not only for the level of adoption, but also for cost-effectiveness.

The importance of policy design emerges in the comparison of investment- and output-based subsidies for wind. Aldy et al. (2023) show that the PTC induced more electricity generation than the Section 1603 grant in lieu of tax credit and was substantially more cost-effective, with the PTC delivering wind power at 29 percent lower cost per megawatt-hour.

Taken together, the literature delivers three broad lessons, each of which shapes the analysis that follows. First, policy can be effective in promoting clean technology innovation, adoption, and in some cases cost reduction. Second, policy design matters enormously. Output-based subsidies, upfront versus back-loaded incentives, and the interaction between subsidies and complementary policies can all substantially affect cost-effectiveness. Third, dynamic effects are central. Policies may have benefits that extend beyond contemporaneous deployment because they can induce learning-by-doing, generate spillovers, and redirect the path of future innovation. This also means that abrupt policy reversals, such as the rescission of most renewable power credits under the OBBBA, may forfeit dynamic benefits that a calculation focused only on immediate fiscal effects would overlook.

Two qualifications carry into the rest of the paper. The first concerns what effectiveness means. Evidence that a subsidy raises deployment is not evidence that it reduces emissions in proportion. Abajian and Pretnar (2024) show that residential solar subsidies increase rooftop adoption but do not fully displace grid electricity consumption, and more generally the emissions consequence of any new zero-carbon facility depends on what it displaces. We develop this distinction in the following section by evaluating the ITC and PTC against a carbon tax benchmark. The second qualification runs the other way. Because dynamic learning and spillover benefits can be large, a tax credit that targets the carbon externality imperfectly may nonetheless be worth its fiscal cost. Our assessment of targeting should therefore be read as identifying where the cost-effectiveness of these tax expenditures could be improved, rather than as a claim that they have delivered little.

[5] Discounting reflects the fact that a dollar received today is generally worth more than a dollar received in the future because it can be used or invested immediately and because future payments may be uncertain. Thus, households that heavily discount future subsidy streams value promised future benefits substantially less than equivalent benefits received today.

III. Targeting the emissions externality through tax policy instruments

A standard policy prescription for addressing a negative externality, such as carbon dioxide emissions, focuses on an explicit targeting of those emissions with a tax. Imposing a price on emissions—in particular, a price equal to the social damages associated with the pollution—effectively causes the sources of emissions to account for the costs they impose beyond their own private considerations. Whether it's a firm or a household internalizing the cost of emitting carbon dioxide, the decisionmaker will explore an array of opportunities for mitigating its emissions so long as the cost for any incremental action or investment to reduce emissions costs less than the emissions tax it would have had to pay otherwise. An analogous decisionmaking process will hold under market-based regulatory approaches that implement cap-and-trade programs. The tradable allowance price (the market-determined cost of a government-issued allowance that grants a company to emit a specific amount of pollution) would serve to provide incentives like the carbon tax.

In the electricity system, a carbon tax would induce a variety of changes in investment, use of existing assets, and exit. A key characteristic of a carbon tax is that it raises the price for emitting carbon dioxide among existing, incumbent sources of emissions as well as any new entrant to the market whose technology would result in carbon dioxide emissions. This vintage-neutrality differs from many conventional regulatory approaches, such as under the Clean Air Act, that distinguish new sources from existing sources, typically resulting in more burdensome regulatory requirements for new entrants than for existing incumbents. Likewise, tax expenditures target new entrants employing specific types of power generating technology, but not incumbents.

An emissions tax is performance oriented. It applies the same price per ton of carbon dioxide emitted to all covered sources. As a result, non-emitting sources—regardless of whether they are among the various types of renewable sources of power or nuclear—bear no tax, while fossil fuel plants will bear a cost from the tax. An efficient natural gas plant will face the same tax per ton of carbon dioxide as an inefficient coal plant, but this tax translates into a much lower tax per megawatt-hour of generation than for coal plants due to the lower carbon intensity of natural gas combustion. Indeed, an efficient combined-cycle natural gas plant may emit about half the carbon dioxide per megawatt-hour of generation as a conventional coal plant. This incentive can spur both improvements in generation efficiency—that is, producing more power from a given unit of natural gas or coal—as well as incentives to switch from coal to natural gas, and from natural gas to zero-emitting sources of power, such as renewables, geothermal, and nuclear.

In pricing fossil fuels, which still represent a significant fraction of the generation mix and a key source of marginal power during many hours of the day, a carbon tax would likely raise power prices. By increasing the price of electricity in the market, the carbon tax can spur demand for both new investment and generation from existing capacity of low- and zero-carbon sources of power. For example, a new wind farm or solar facility could sell power into this higher-price environment and realize higher returns than it would in a policy environment without a carbon tax. For that matter, an existing nuclear facility, which may be considering whether to retire at the end of its current operating license or petition its

regulator for an extension, may realize higher returns under a carbon tax and thus remain in the market as a zero-emissions source of power for a longer period of time.

These higher electricity prices would also induce electricity consumers to conserve energy and invest in energy efficiency. This creates another opportunity for reducing emissions, by reducing power demand through the enhancement of the productive use of electricity. This may be particularly important in the context of increasing electricity demand due to data centers and electrification.

Finally, pricing carbon dioxide emissions creates a technology-neutral incentive for innovation. Any technology or process that could enable lower emissions for a unit of energy services—whether it's through low- or zero-carbon sources of power, or by realizing greater service for a given unit of power—can enter into a market that rewards these characteristics under a carbon tax. This may enable lower-cost compliance as well as greater emission reductions under a carbon tax.

In sum, the carbon tax creates incentives to reduce emissions for both incumbent sources and new entrants. In pricing the emissions of incumbents, it delivers a targeted incentive to the most pollution-intensive power generation units to exit the market. It encourages reduced use of emission-intensive sources, and increased use of emission-lean and zero-emission sources of power. A carbon tax would attract entry of lower-emitting sources to meet electricity demand. It can drive increased conservation and investment in more energy efficient equipment and technology. It would drive innovation toward lower-carbon technologies in a manner that is purely a function of the carbon intensity of the technologies, thus attracting the broadest possible array of new ideas to lower emissions.

The carbon tax faces several fundamental political challenges. It imposes costs on a concentrated set of incumbents, with considerable political influence, and creates benefits for an emerging set of new firms that are less well-organized and influential. A carbon tax would very likely raise power prices, which has long drawn political opposition and would appear to be even more salient as a political concern given the significant increase in power prices in 2025 and 2026.

Tax expenditures for zero-emitting sources of power, most notably the investment tax credit (ITC) for solar facilities and the production tax credit (PTC) for wind facilities (and other renewable sources of power, although wind has been the technology that claims the vast majority of these tax expenditures) have served as a more politically viable means of addressing carbon dioxide emissions through the tax code. There are conditions—very strong conditions—in which a subsidy for a facility that does not emit a negative externality could realize the same social welfare outcome (although with different distributional consequences) as a tax on the negative externality (Baumol and Oates 1988; Aldy et al. 2022). In practice, these conditions—on abatement technology, the firm, the nature of competition in the market, and the design of the tax expenditure—do not hold. We present two stylized examples that illustrate how subsidy implementation in practice—through the Internal Revenue Code—delivers different and suboptimal incentives relative to a carbon tax.

As noted, the developer of a solar facility has long had the opportunity to claim an investment tax credit equal to 30% of qualifying investment expenditures. This subsidy, by

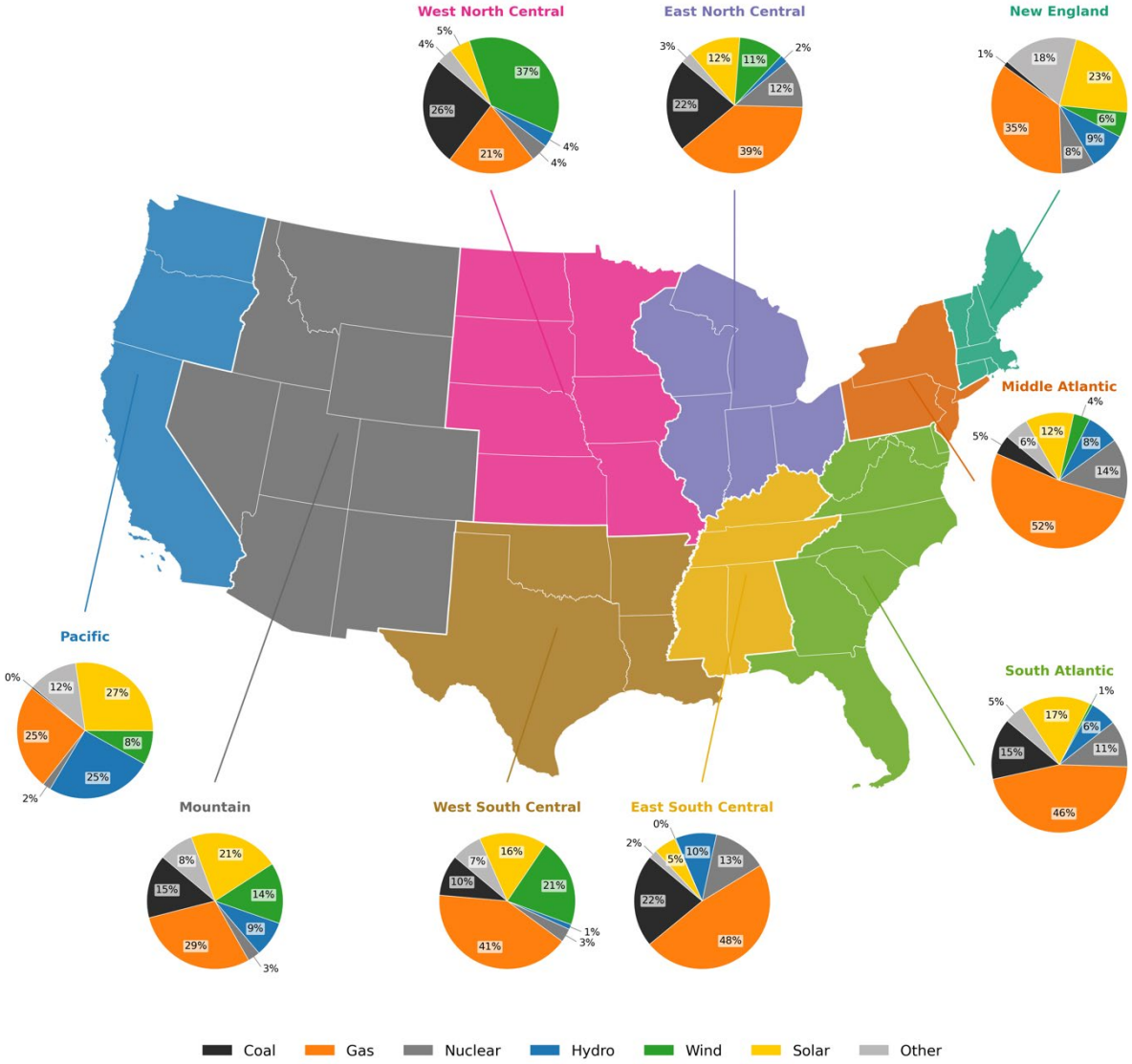
design, does not target the emissions externality. The cost of a zero-emission technology is unrelated to the emissions externality associated with a set of its competitor technologies in the power market. The federal government covered 30% of the costs of a solar facility in 2009 and in 2016 (as well as every year in between), even though the cost of a solar panel fell 80% over that time period. Because other categories of investment costs did not fall as rapidly, the subsidy per megawatt of capacity did not decline as much as the price of solar panels, but it does suggest a significant decline in tax expenditure for a given unit of generating capacity over a period when the estimated social cost of emitting carbon dioxide was increasing in formal policy analyses (Aldy et al. 2021). As a percentage of investment costs, the implicit subsidy per megawatt-hour of zero-emissions electricity fell over time for the solar ITC. The emissions impact, however, also depends on what the new solar facility displaces in the existing generation mix.

A new solar facility may reduce dispatch from existing fossil fuel plants during high-value solar hours of the day, such as midday through midafternoon. In some markets, this could reduce dispatch of natural gas-fired power, and in other markets it could reduce dispatch of coal-fired power. To the extent that solar helps address extremely high-load days, such as the warmest days in the summer, it may reduce dispatch from less efficient (and more emission-intensive) natural gas combustion turbine generating sources, which may have emissions per megawatt-hour about midway between combined-cycle natural gas and coal plants. What a new solar facility could displace will vary across geography, over the day, and across seasons. This displacement typically does not target the most emission-intensive sources of power, such as an old, inefficient coal-fired power plant that runs all day, including at night. Thus, the emissions impact will likewise vary across these dimensions.

What a new facility stands to displace depends on the generation facilities already in place, and while the terms of the federal tax credits apply uniformly across the country, spatial variation in energy resources has left the generation mix highly heterogeneous (Figure 8). Hydropower, wind, and solar account for around 60% of installed capacity in the Pacific Census division. Wind makes up 37% of capacity in the West North Central division and 22% in the West South Central division, while solar accounts for over one-quarter of capacity in the Pacific division and over one-fifth in the New England division. Renewables play a much smaller role in the East South Central, South Atlantic, and Middle Atlantic divisions, where natural gas—complemented by coal in the first two—makes up the bulk of the fleet. A solar or wind project claiming a credit on identical terms therefore enters a very different market depending on where it is built and displaces power of a correspondingly different type and emissions intensity.

FIGURE 8

Geographic heterogeneity in installed power capacity, 2025



Notes: 1. Data source: EIA form 860 and form 861. 2. Alaska and Hawaii are excluded; the Pacific division covers California, Oregon, and Washington.

These differences show up directly in the emissions intensity of displaced power across the states with wind and utility-scale solar investment in 2023. Based on the Environmental Protection Agency's AVERT model, which produces estimates of the marginal intensity (tonnes of carbon dioxide per megawatt-hour of electricity) of the power displaced by renewable investment, the marginal intensity of displaced power generation varied from 0.44 *tCO₂/MWh* in New York to 0.76 *tCO₂/MWh* in Colorado for wind, and 0.46 *tCO₂/MWh* in Florida to 0.76 *tCO₂/MWh* in Utah for solar (U.S. Environmental Protection Agency 2026a). For wind projects, the tax expenditure per ton of carbon dioxide displaced is 73 percent higher in New York than for Colorado. If the solar investments in Florida and Utah realize the same capacity factor and operating lifetimes, then there would be a similar

difference in tax expenditure per ton of emissions displaced as well in the solar power context. This differs substantially from the geographically-uniform, cost-effective price per ton of emissions under a carbon tax.

A new solar facility may create some downward pressure on prices by increasing supply, but this will be a relatively weak incentive to reduce emission-intensive incumbent sources of power. Such an effect would be spread across all incumbent sources of power, and it would not distinguish between an inefficient coal plant, an efficient combined-cycle gas plant, or a zero-carbon nuclear power plant. These would tend to be localized power market impacts in those geographies in which a meaningful set of new solar facilities came online in response to the tax expenditure. Again, in some markets, solar may not be technically and commercially viable, and thus the presence of the ITC does not influence outcomes in these markets. Thus, it is unlikely that building new renewable facilities would spur exit of the most pollution-intensive generating sources.

By expanding supply and creating downward pressure on power prices, renewable subsidies may be politically appealing, but they would also undermine the incentives for conservation and energy efficiency that could be realized under a carbon tax. In addition, the ITC for solar has not spurred innovation in a technology-neutral manner.[6]

The PTC for wind would have similar impacts on the power system as the ITC for solar. A production subsidy can drive greater generation of zero-carbon electricity than an investment subsidy (Aldy et al. 2023). It provides an incentive not only to install renewable energy but also to maintain the generation of the renewable energy plants, as the payment is made based on the production of electricity, not just the amount invested.[7] In most U.S. markets in which the emissions externality from fossil fuels remains unpriced (by a carbon tax or an emission trading system), inducing greater generation on the margin could increase social welfare by displacing fossil fuel sources of power. Except for this distinction, however, the PTC has properties very similar to those of the ITC in comparison to the carbon tax benchmark. The PTC does not target high-emissions geographies or time periods. New wind projects claiming the PTC may reduce power market prices, but like the solar ITC case, these would not discriminate among incumbents as a function of their emission intensity. Indeed, the Exelon Corporation, formerly the largest producer of electricity from nuclear power plants in the United States, criticized wind power and the PTC as reducing the profitability and encouraging the exit of several carbon-free nuclear power plants (Snyder and Johnsson 2013).

A national carbon tax applies to all fossil fuel sources of power and, given the current mix of fossil fuels, will determine electricity prices and incentives for exit and entry for all power generating sources, fossil and non-fossil alike. In contrast, tax expenditures for new renewable power generating sources do not have the same energy system-wide incentives and impacts. Some regions may have poor solar or wind resources, and thus experience very little incremental investment under these tax expenditures. Some regions may be

[6] In the Inflation Reduction Act of 2022, Congress established the first technology-neutral ITC and PTC for the power sector.
[7] A possible trade-off could be that having the ITC in hand at the time of investment might enable financing for a renewable project, potentially inducing more renewables installed per dollar than the PTC, although not necessarily more generation over the longer term.

experiencing significant electricity demand growth, and thus new renewable sources subsidized through the tax code may help meet this demand. In the context of growing demand, however, the new renewable sources may not meaningfully reduce power prices and thus produce little incentive for incumbent fossil fuel sources to exit the market. Individual firms will make decisions on when and where to build new renewable facilities under favorable tax expenditures, and these will result in a heterogeneous patchwork of power system impacts and incentives across the country.

Clean energy tax credits also do not operate in isolation from the other policies aimed at the same externality, and these interactions can either reinforce or displace those policies. A carbon tax and a clean energy tax credit are complements in one direction. By raising the price of fossil-fired power relative to clean alternatives, a carbon tax raises the returns to the marginal subsidized project and spurs additional clean energy investment. The interaction with state Renewable Portfolio Standards runs in the other direction. If clean energy tax credits are sufficiently generous to spur investment and generation beyond what a state's standard requires, the standard no longer binds on utilities in that state and becomes irrelevant at the margin; the tax credit has substituted for the standard rather than added to it. The same logic applies among the tax expenditures themselves and to the array of non-tax subsidies illustrated in the case studies above. Stacked incentives may be jointly necessary to move a marginal project, or the most generous instrument may simply render the others redundant, and the distinction matters for any accounting of what a given tax expenditure bought.

In short, tax expenditures for renewable power have been an imperfect substitute for a carbon tax. They support individual power project investment—reflecting the profit-maximizing decisions of project developers—as opposed to imposing a system-wide price on emissions. Having more electricity capacity coming online quickly may be especially politically attractive given the rapid growth in electricity demand from data centers and electrification, as it would lower electricity prices rather than raise them. But the tax expenditures are indirect approaches to reducing emissions that target entry of zero-carbon sources of power and do not directly influence the exit decisions of fossil fuel incumbents or the entry of new fossil fuel generating sources.

IV. Policy reforms to drive greater renewable power development

We explore two types of policy reforms that could facilitate more rapid investment in renewable power. In the first subsection, we describe various modifications to tax expenditures that could improve the targeting of the carbon dioxide externality, promote more output per unit of investment, and reduce the transaction costs of realizing the value of tax credits. In the second subsection, we describe reforms to various power sector regulatory regimes that impose higher than necessary costs on new renewable power development.

A. Enhancing the cost-effectiveness of renewable power tax expenditures

Historically, clean energy tax credits in the power sector have typically been technology-specific and externality-neutral. In other words, they have identified specific qualifying technologies (for example, wind and geothermal qualify for the PTC, and solar qualifies for the ITC), but do not require any consideration of the displacement of carbon dioxide emitting power. Under the Inflation Reduction Act, the tax code evolved toward a technology-neutral approach, granting the taxpayer (for instance, the project developer and its financial partners) the option of selecting the PTC or the ITC for any zero (or low) emission technology (as defined in subsequent Treasury regulation). Again, this focuses on the characteristics of the clean energy project, without an assessment of its net impact on emissions in the energy system.

The Inflation Reduction Act of 2022 included a variety of provisions that modified the value of the PTC and ITC, including for projects satisfying specific wage and apprenticeship conditions (analogous to the Davis-Bacon Act[8] prevailing-wage requirements that apply to federal spending programs), employing a minimum of American-manufactured components, as well as place-based bonuses for locating in energy communities.[9] Table 2 illustrates how the generosity of the tax expenditure varies with these project characteristics.

TABLE 2

Value of PTC and ITC in 2025, under various project development conditions

	(1) No Wage and Apprenticeship	(2) Labor Conditions Met	(3) (2) + Domestic Content	(4) (3) + Energy Community
PTC	$6/MWh	$30/MWh	$33/MWh	$36/MWh
ITC	6%	30%	40%	50%

Notes: Data source: Internal Revenue Service (2025); Buffie (2025). All values already expressed in 2025 USD.

Two wind (solar) farms could generate the same amount of output (incur the same investment cost), and yet the tax expenditure per project could vary by a factor of 6 (8) based on externality-neutral project characteristics. Given the geographic variation in emission intensity in the U.S. power system, only the place-based energy community bonus could, in theory, modify the value of the credit in a manner that effectively targets displacement of more emission-intensive generation. In practice, however, this does not appear to be the case. Based on estimated marginal emission intensities of the power displaced by new wind and solar projects in 2023 under the Environmental Protection Agency's AVERT model and the Department of Energy's 2024 map of eligible energy communities under the Inflation Reduction Act, energy communities have about 3% lower

[8] The Davis–Bacon Act, enacted in 1931, requires contractors and subcontractors working on federally funded or assisted construction projects to pay locally prevailing wages and benefits.

[9] The Inflation Reduction Act also provided place-based bonuses for the ITC for locating in low-income communities or tribal lands, although these bonuses only applied to small systems with no more than 5 MW of capacity.

intensity than non-energy communities. Thus, these provisions that conditioned the value of the tax expenditure by the characteristics of the project did not do so in a way that more effectively targeted the emissions externality (that is the more emission-intensive regions in the U.S. power system).

There is a precedent, however, for conditioning the value of tax credits on characteristics of the energy system. Specifically, the 2015 Omnibus law extending the PTC for wind included an adjustment to the tax expenditure per megawatt-hour based on Treasury Department calculations of the annual average contract price for wind power sold in the preceding year. If this average contract price exceeded the reference price set in the law, then the PTC would be phased down (and potentially phased out) as a function of the magnitude of the excess of the average contract price. Alternatively, a PTC schedule could adjust as a function of the marginal emission intensity of the relevant market in the preceding year (such as described in the previous section using the U.S. Environmental Protection Agency (2026a) framework). Defining the relevant market could be determined by the state or the market (for example, the Independent System Operator market or vertically-integrated regulated market) the project would connect into. By scaling the value of the tax credit as a function of a region's marginal emission intensity in the preceding year, the tax code could encourage investment in more emission-intensive areas and spur earlier entry into these areas (that is, before other zero-emission power project developers enter and drive down the emission intensity and hence value of the tax credit).

Commercially competitive storage today enables short-term arbitrage in local power markets. With the penetration of solar power capacity—accompanied by its typical peak generation around early afternoon—some markets realized so-called "duck curves" in wholesale electricity prices over the course of a day. The price curve from morning through late evening resembled that of a duck: medium prices in the morning (the duck's back), followed by low (and sometimes negative) prices in the afternoon (the swale between the back and the head), and high prices at night (the duck's head). Storage enables the shifting of solar power for consumption from low-price early afternoon hours to higher price evening hours. This also increases the likelihood that solar plus storage displaces marginal natural gas in the evening, instead of cannibalizing other solar in the early afternoon. Continued support for battery storage could further enable this kind of economic arbitrage that in turn could deliver environmental benefits. An additional step to enhance cost-effective emission reductions would be to identify the marginal emissions for storage as a function of the daily peak marginal emissions in a given market, and this could be used to condition the value of the storage tax credit.

In developing technology-neutral tax credits, the Inflation Reduction Act granted taxpayers developing a qualifying clean energy project the option of selecting the ITC or the PTC. In the preceding 30 years of tax policy, taxpayers had such discretion over the type of tax credit they could claim only over 2009–2012 under the American Recovery and Reinvestment Act of 2009 and the 2010 Omnibus. In this period, a wind project (or geothermal or other PTC-eligible project) developer could claim the PTC, the ITC, or the Section 1603 grant in lieu of the tax credit. The face value of the 1603 grant was effectively equal in value to the ITC, and about two-thirds of utility-scale wind power projects claimed the 1603 grant during this period. About one-third of wind projects claimed the PTC; there were no ITC claims. The PTC, by subsidizing output, caused wind farms to generate about

10 percent more power than the 1603 grant, which subsidized the capital investment (Aldy et al. 2023). These output incentives leveraged opportunities for learning, adjustment, and maintenance of wind farms to enhance their output. Focusing future subsidies on output would likely increase the generation per dollar of subsidy.

The challenge for some developers, however, lies in securing sufficient capital to advance a project. They may find it easier to finance a project with an expected tax credit equal to 30% of investment costs paid out in the year a project is placed into service against a stream of uncertain tax credits (due to greater uncertainty about future generation than up-front investment costs) over the next 10 years under the PTC.

It is also important to stress the primary advantage of the 1603 grant: It enables a project developer to avoid the tax equity market and thus capture the full face value of the subsidy (Aldy 2013). Before the 1603 grant, project developers typically had insufficient tax liability to monetize their tax credits. Thus, they partnered with financial institutions that would monetize the tax credit by supplying so-called tax equity: The financial institution makes an equity investment and it retains the claims to the project's tax benefits. This service cost projects about 15 cents on the dollar (Johnston 2019). Thus, 15% of federal subsidy dollars went to financial institutions so that clean energy developers could claim the residual 85% for investing in a clean energy project. The Inflation Reduction Act introduced the opportunity to transfer a tax credit from a developer to another taxpayer who would have sufficient tax liabilities to take full value of the tax credit. This transferability significantly reduced, but did not eliminate. the cost of monetizing the value of tax credits for renewable project developers. Early anecdotal evidence suggested that the seller of a tax credit realized about 95% of the tax expenditure in large transfer transactions (Aldy 2025). Focusing future subsidies for clean power generation on output-based measures that minimize the transaction costs necessary to realize the subsidy could significantly enhance the cost-effectiveness of the tax expenditure.

One approach that could realize several objectives would be to increase the effectiveness in targeting the externality and reduce the transaction costs of realizing the subsidy, subject to a constrained fiscal environment. Suppose that Congress aspires to maximize the decarbonization impact of $100 billion in clean power tax expenditures. A technology-neutral electricity sector tax credit could be structured as a competitive, allocated tax credit premised on the expected emissions of carbon dioxide displaced by the projects. Congress could allocate $100 billion over 10 years with 10 annual competitive allocations of tax credits. In each annual competition, projects that will be placed into service in that year could submit applications with their expected annual generation and the emissions intensity of their generation. This would be zero for wind and solar projects but could be non-zero for a natural gas plant with 90% carbon capture and storage efficiency, for example. Based on a project's location and the marginal emission intensity of displaced generation associated with that location, the Internal Revenue Service would allocate a 10-year claim to refundable production tax credits going through the ranking of project applications from highest to lowest net expected emission displacement until the annual aggregate allocation is exhausted. If a selected project in a given future year fails to generate its expected quantity of power (or realizes a higher emissions intensity than it expected at the time of application), then its tax credit is reduced. The residual resources are reallocated on a proportional basis to facilities that produce more than their expected annual generation in

their tax credit application. Such an approach would focus tax expenditures on the projects that displace the most carbon dioxide emissions and, by making this a refundable tax credit, would circumvent the need for financial transactions to monetize the subsidy.

B. Shadow costs slowing renewables adoption

A conventional assessment of a proposed renewable power facility—accounting for its capital and operating costs and expected market conditions (or secured long-term power purchase agreements)—may appear to reveal a financially viable project, and yet it may not proceed without a subsidy. This seeming contradiction is often not due to analyst error, but rather an array of shadow costs or hidden costs that are borne disproportionately by new renewable power projects because of current power sector regulations and market design. In this section, we describe four major categories of shadow costs and illustrate how tax expenditures for renewable power investment or production serve as an imperfect strategy for overcoming these shadow costs.

Each of these categories of shadow costs lends itself to regulatory reforms—to the interconnection queue, transmission infrastructure permitting, local market power, and reliability standards—that could enable greater renewables adoption. Each category is also likely to interact with various tax policy instruments. It is useful to distinguish policy-driven shadow costs from technological costs. Most of the shadow costs on which we focus are policy-driven and relate to inefficient regulation or policy design. Some are technological, however, such as the very real costs of grid integration.

We begin by adding precision to what we mean by shadow costs. As discussed above, renewable projects are developed based on the present value of expected future profits. Investment happens upfront, which usually requires financing, while the benefits are realized later when the project is operational. This can be seen in the following equation in which the expected profit is written as the discounted sum of the revenues in each time period, R_t, minus the upfront fixed costs, FC_0:

$$\mathbb{E}[\pi] = \sum_{t=t_0}^{T} \frac{\mathbb{E}[R_t]}{(1+r)^t} - FC_0$$

The shadow costs or hidden costs tend to work through two channels. First, they may increase the upfront fixed costs FC_0, thus directly influencing the expected profits. Second, they may delay the start of the project, which serves to both increase the FC_0 by requiring employees working on the project to be paid during that period and also push back the revenues to a later date that is discounted at a higher rate. Both will be discussed below.

1. Interconnection queue

For any planned new power plant, the grid operator must provide approval before the generator can transmit electricity into the grid. This interconnection approval process typically involves an analysis of the costs that would be incurred by the electricity system should the new generator begin sending electricity into the grid. Integrating a new

generating facility into the grid may require new transmission lines, transformers, and related grid investment. These costs are then charged to the new generator to keep the grid whole and not add new charges to ratepayers. In theory, there is no issue with this process. The challenge comes in practice. For many years, the interconnection process was relatively fast, as only a small number of (generally large) power plants required approval each year. But more recently, the number of proposed generators looking to interconnect has expanded rapidly, as solar and wind farms tend to be much smaller and there are many of them proposed in recent years as costs have dropped (Rand et al. 2024). Thus, what is called the "interconnection queue" has gotten very long and the time it takes for approval has extended into multiple years in some regions of the United States (Johnston et al. 2023).

Indeed, the median duration in the interconnection approval process has increased by more than two years as of 2024 (Rand et al. 2025). Going back to our equation above, if we assume a discount rate of 7% and a lifetime of 30 years, a two-year delay in starting operations will reduce the lifetime present value of expected profits by about 13%. For example, consider the Shepherds Flat wind farm, assuming an average capacity factor of 35%, the two-year delay would cost the developer about $160 million. This hidden cost can deter developers. Over 2017–2025 across the major power markets (independent system operators), a one-year increase in duration of the average time spent in the interconnection queue is associated with about 65 megawatts less annual wind power capacity investment per market.[10] This is approximately equal to the difference in queue duration between the PJM (PJM Interconnection LLC) and ERCOT (Electric Reliability Market of Texas) markets, on average over 2017–2025, although the difference has increased significantly in recent years.

In February 2022, PJM paused accepting new applications in its interconnection queue. The market operator indicated it would work through the queue before it would accept new applications. Later that year, the Inflation Reduction Act passed with extensions and modifications to the PTC for wind and ITC for solar, and eventual transition to a technology-neutral tax credit regime that would apply to wind and solar. PJM reopened the queue, with an initial deadline of April 27, 2026 (Winer 2026). This occurred, however, after the 2025 OBBBA effectively sunset the tax credits for wind and solar unless they had begun construction by July 4, 2026, and were placed into service by the end of 2027. By the end of 2025, the median annual duration of the PJM interconnection queue was 83 months (Lawrence Berkeley National Laboratory 2026). In practical terms, a taxpayer initiating a new project from scratch would have been unable to complete the interconnection process and place the project in service within the relevant credit window.

The interconnection process is not per se discriminatory against renewable energy; new fossil fuel projects face the same process, and they too have been subject to long queues. However, renewable generation is still growing and accounts for most new project requests,

[10] This reflects a simple regression model drawing on data on incremental renewable power capacity from EIA form 860 and 861, as represented in Figure 1, and interconnection queue duration data from Lawrence Berkeley National Laboratory (2026). We mapped state-level capacity investment data to these markets: CAISO (California Independent System Operator), ERCOT, MISO (Midcontinent Independent System Operator), NYISO (New York Independent System Operator, Inc), PJM, and SPP (Southwest Power Pool), as well as for non-ISO (independent system operator) southeast and west region regulated markets.

while fossil generators form the dominant stock—gas and coal made up 40% and 13% of total capacity in 2025 (see Figure 1)—and would be the marginal resources relied upon if renewable projects were delayed. By the end of 2024, 92% of overall queued capacity was solar, storage, and wind (Rand et al. 2025); the burdensome interconnection queue is therefore disproportionately a problem for renewable energy development. At a high level, interconnection is a genuinely necessary process, so in some sense, this shadow cost is technological. But extremely long interconnection queues point to a policy-driven cost.

2. Permitting

In addition to the interconnection approval, many other permits are needed to enable additional electricity generation. This applies to both the electricity generation itself as well as transmission infrastructure needed to allow clean energy generation to reach the final markets. For electricity generation, state and local permits are needed for land use, which has held up many renewable energy projects due to NIMBYism. But the challenges have proved even greater when considering transmission permitting. The development of new large-scale transmission lines involves a multi-layered and often lengthy process, which includes obtaining permits or approval from local, state, interstate and federal authorities regarding land use, environmental compliance, and grid connection (Sud and Patnaik 2022). According to a survey of renewable energy developers (Bauer et al. 2024), local ordinances or zoning, grid connection (that is, the interconnection queue), and community opposition are the top three barriers to renewable energy development. To illustrate how easier transmission permitting could amplify the impact of a given suite of tax expenditures, Jenkins et al. (2022) estimate that doubling the recent years' rate of new transmission construction could increase the emission reductions enabled by clean power tax credits under the Inflation Reduction Act by a factor of four.

More broadly, permitting has become deeply entangled in the political economy of the different stakeholders on the grid, and resolving cost allocation issues for new transmission can further slow or entirely hold up new transmission lines (Davis et al. 2023). The permitting would impinge upon the economics of new renewable generation in a similar way as the interconnection queue by slowing the process of development and construction. Further, if sufficient transmission is not available, the revenue, denoted R_t above, will be lower because the renewable energy development will receive a lower market price. This hidden cost is unquestionably a policy-driven cost.

3. Imperfect competition

Imperfect competition and regulated local monopolies have also been shown to slow the rollout of new transmission lines. Hausman (2025) provides convincing evidence that incumbent local monopolies in certain areas have a financial incentive to impede the construction of transmission lines that would bring cheaper power into their region, thus lowering wholesale electricity prices and reducing the local monopoly's profits. The incentives and market conditions documented in Hausman (2025) are also present in many other regions of the United States. This would affect the economics of new renewables development in the same way as permitting. Imperfect competition is not technological, although there may be aspects of technology that make a market more likely to have imperfect competition. It is a regulatory-driven hidden cost.

4. Reliability standards

Renewable power plants are imperfect substitutes for conventional fossil fuel power plants. A key difference is dispatchability—the ability to dispatch energy into the grid when requested. A manager of a fossil fuel power plant can select when to ramp up generation to meet either an increase in demand (or a reduction of supply by a nearby plant), but a manager of a renewable facility cannot dispatch power in response to variation in residual demand. This can increase the value of the power produced by dispatchable sources and can ensure that power is reliably available to consumers. To ensure that the lights (almost) always come on when a consumer flips a switch, U.S. regulators have established rigorous standards for reliability. These standards are legally binding and define technical parameters for grid equipment and operation, as well as benchmarks for reliability actions and backup capabilities.

Customers clearly value the insurance implicit in reliability standards, and dispatchable resources are rewarded in these markets for delivering such insurance. The challenge for renewables, especially as the renewable share of the generation mix increases in any given market, is that they provide much less of this insurance service. This necessitates either a dispatchable source of power (such as a fossil fuel plant), increased transmission to enable trade to manage supply shocks, or battery storage to enable shifting across time. Moreover, the reliability standards are implemented in varying ways across U.S. markets, and some of the rules of thumb employed by regulators fall far short of the cost-minimizing regulatory design (Graf et al. 2026). Indeed, the costs of reliability standards in practice may be double the cost-minimizing design. These costs translate into an inefficiently high value associated with dispatchable (and typically emitting) sources of power, which can slow exit of such sources as well as encourage more entry of emitting sources at the expense of renewables. These reliability standards also create strong incentives to pair renewable facilities with battery storage to allow for some degree of dispatchability. These are technological hidden costs, as at a basic level, reliability standards are needed. But they can lead to much higher costs due to policy design, akin to interconnection costs.

5. Policy implications

With these hidden costs deterring entry of renewables, the same tax credit will be less attractive to new entrants, resulting in smaller tax expenditures but also less renewable energy development and slower progress toward energy and climate goals. Moreover, if these shadow costs vary across regions—for example, because permitting or grid-connection barriers are more severe in some places than in others—they can distort where renewable energy projects are developed and thereby reduce the cost-effectiveness of tax expenditures.

Each of these categories of shadow costs provides an opportunity for regulatory reforms. Streamlining permitting is very possible and has been discussed extensively in Congress.

Reforming the interconnection process so that it is much faster has also been much discussed. This could include performing analyses in batches and simply allocating more resources toward performing faster and more analyses of the costs to the grid from interconnecting new power plants. Regulators can also aim to streamline permitting for transmission lines that are being held up by local monopolies. They could further improve

the cost-effectiveness of reliability standards. Cutting the regulatory red tape would deliver faster clean energy deployment.

All these potential reforms would lower the barriers to renewable entry, increasing the number of economically viable projects and inducing higher deployment overall. Although this would move the country closer to its energy and climate goals, the total subsidies in the tax code would also increase due to greater claims for the PTC, unambiguously, and likely for the ITC, given the past record in which falling solar panel costs resulted in increasing ITC expenditures despite a falling per-unit capacity investment cost. That said, if the goal is to reach a certain renewable generation mix and ensure adequate electricity supply, removing these barriers would allow tax credits to play a larger role. Given a limited fiscal budget, lowering shadow costs could make it feasible to incentivize more entry with smaller per-unit subsidies, as each project would require less support to become viable. The recent sunsetting of renewable power tax expenditures under OBBBA of 2025 has created an ongoing policy experiment that could inform whether any tax expenditures are still required to spur wind and solar power deployment in the United States.

The recent experience of renewable power development in Texas, which is characterized by a less-stringent permitting regime for facilities and transmission, less time-consuming interconnection processes, and competitive power markets, illustrates the potential for dramatic renewable power growth in the presence of lower regulatory costs. In 2025, more than one-quarter of all U.S. utility-scale solar power capacity investment, and likewise more than one-quarter of all U.S. wind power capacity investment, occurred in Texas[11]. As regulatory costs fall, a key question is what the necessary tax expenditure would need to be to continue to spur renewable power development.

V. Conclusions

U.S. power sector emissions have fallen more than 35% since 2000. While this reflects an array of market factors, such as low-cost natural gas displacing coal-fired power generation, a key driver has been the improving economics of renewable power. Dramatic technological innovation has reduced costs and increased the productivity of wind and solar technologies. As a result, most additions to power-sector generating capacity over the past five years have been renewable, particularly wind and solar. Federal tax expenditures have both facilitated deployment and enabled this innovation in zero-emitting sources of power.

Making significant progress in decarbonizing the U.S. economy will very likely require both a much more emission-lean and larger power sector. By electrifying various energy services currently met through fuels and decarbonizing power, the United States could amplify emissions abatement throughout the economy. Widespread electrification may not be easy, and it is further complicated by fast-growing power demand by data centers. But

[11] Authors' calculations from EIA form 860M, counting utility-scale generators reporting a 2025 operating date. Texas accounted for 27.5% of the 29.4 GW of U.S. solar capacity and 27.4% of the 6.1 GW of U.S. wind capacity added in 2025, measured on a nameplate basis; the corresponding net summer capacity shares are 27.7% and 27.6%. Small-scale (under 1MW) solar, which is not covered by form 860M, is excluded from both the numerator and the denominator.

the tax code could play an important role in delivering this vision of electrification coupled with decarbonizing power, even if the political challenges of carbon pricing are likely to lead to continued interest in directly subsidizing clean energy. Indeed, the Inflation Reduction Act of 2022 contained many subsidies for clean energy. The promise of the bill was that clean energy funding would flow to many different congressional districts, building a political bloc to support clean energy. Yet, these subsidies did not prove to be politically durable, and nearly all the subsidies for renewable power were rescinded in the OBBBA of 2025.

More broadly, the experience of clean energy tax policy illustrates the growing importance of tax expenditures as instruments of federal fiscal policy. As these provisions have expanded in scale, questions of policy design have become increasingly important alongside questions of budgetary cost. The analysis in this paper suggests that improving the targeting of clean energy tax expenditures and reducing regulatory barriers could increase the emissions reductions achieved for a given level of forgone federal revenue. More generally, as policymakers confront competing fiscal priorities, greater attention to the effectiveness and cost-effectiveness of tax expenditures will be essential to ensuring that the tax code delivers the greatest public value for the resources it commits.

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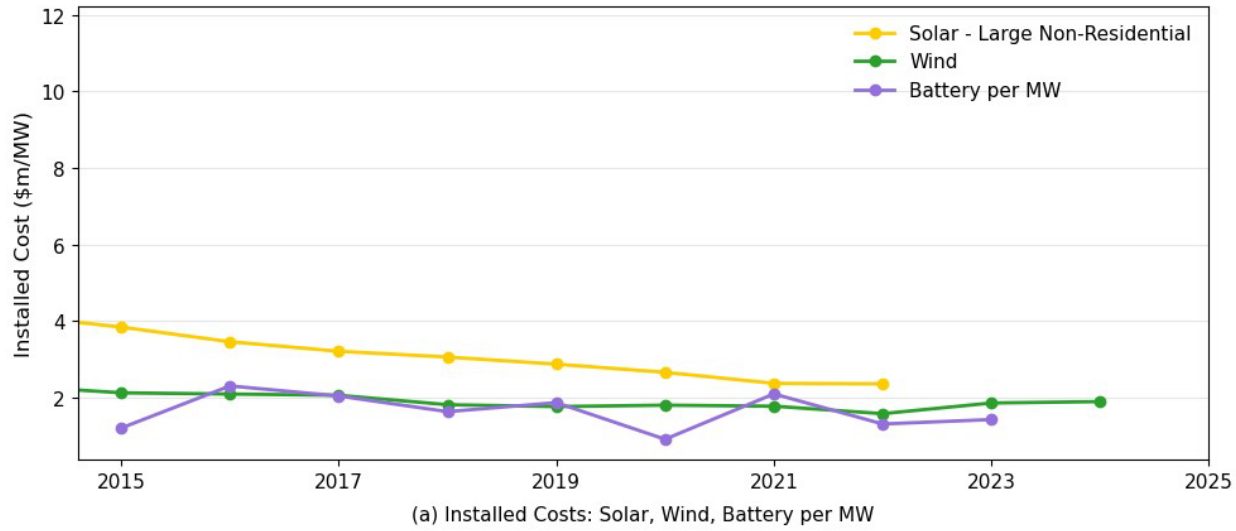
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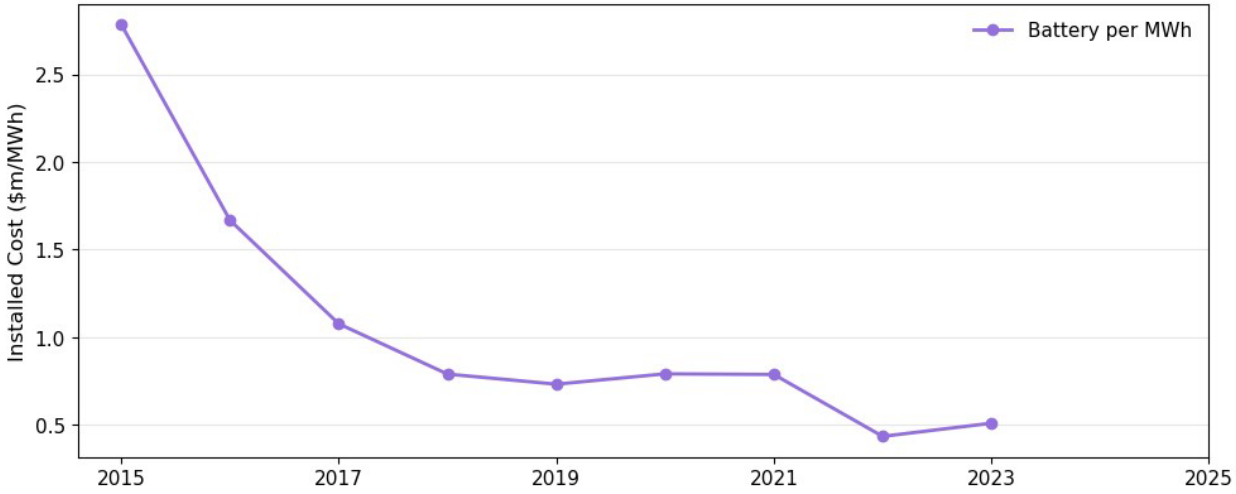
Appendix A: Additional figures and tables

FIGURE A1

Prices for battery storage 2015–2023: Per power capacity (MW) and energy capacity (MWh)



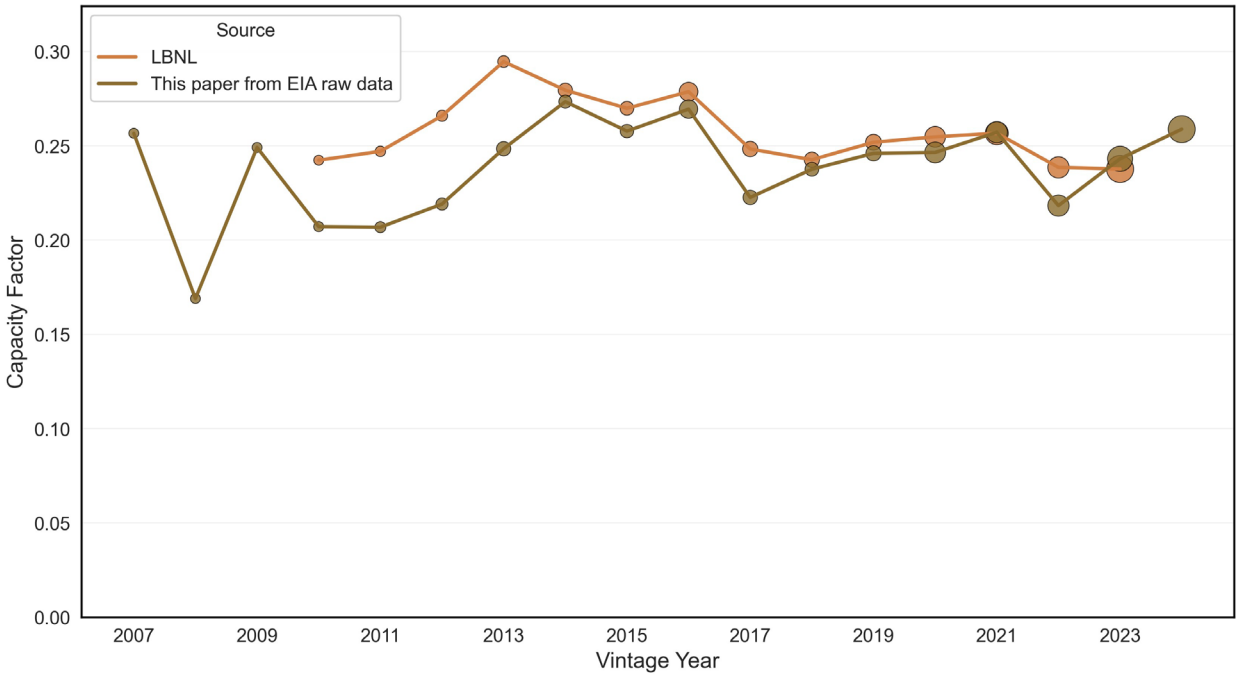
(a) Installed Costs: Solar, Wind, Battery per MW



(b) Installed Cost: Battery per MWh

FIGURE A2

Capacity factor comparison: This paper & LBNL



Appendix B: Data sources and processing

B.1 Figure 1

Data sources:

1. EIA Form EIA-860 Annual Electric Generator Report (https://www.eia.gov/electricity/data/state/, accessed on Feb 9, 2026):

- 2000–2024: Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State.
- 2025: Proposed Nameplate and Net Summer Capacity by Year, Energy Source, and State. Because the proposed capacity file reports planned additions rather than total installed stock, 2025 values are constructed by adding planned 2025 additions to the 2024 existing capacity for each state–fuel–producer-type cell.

2. EIA Form EIA-861M (https://www.eia.gov/electricity/data/eia861m/, accessed on Feb 9, 2026): Small-scale solar PV (system capacity <1 MW) is not covered by EIA860. Annual state-level small-scale solar capacity is sourced from Form EIA-861M for 2014–2025, each year taken from that file's December snapshot.

Data Processing:

Capacity is reported in net summer capacity (MW) and converted to GW for display. Records are filtered to the Total Electric Power Industry producer type to avoid doublecounting utility and non-utility generation. All years represent end-of-year installed (or planned, for 2025 utility-scale) capacity.

B.2 Figure 2

Data sources:

1. Solar (panels a and b):

Lawrence Berkeley National Laboratory (LBNL), "Tracking the Sun" program. File:

Utility PV Installed System Cost Breakdown_2010_2024.xlsx, sheet "LBNL_Component_Costs" (Seel et al. 2025). The dataset reports median installed system prices by project type (Residential, Small Non-Residential, Large Non-Residential) for utility and distributed PV in the United States. Original values are in 2022 USD/W (i.e., $/W); here converted to 2025 USD/MW using the U.S. GDP deflator (FRED series GDPDEF)

(U.S. Bureau of Economic Analysis 2026).

2. Wind (panel c):

Lawrence Berkeley National Laboratory (LBNL), "Land-Based Wind Market Re-

port: 2025 Edition." File: *DATA FILE_Land-Based Wind Energy Technology Update_2025 Edition.xlsx*. CapEx data from sheet "CapEx Over Time" (capacity-weighted average installed cost, by commercial operation date); turbine prices from sheet "Wind Turbine Prices" (transaction-price index, columns L:M) (Wiser et al. 2025). Original values are in

2024 USD/kW; converted to 2025 USD/MW using GDPDEF (U.S. Bureau of Economic Analysis 2026).

Inflation adjustment: Solar prices (originally 2022$) and wind prices (originally 2024$) are adjusted using the GDP deflator series from FRED (quarterly; annual average used).

B.3 Figure 7

Data sources: IRS Statistics of Income. Corporate and Individual Income Tax Returns Line Item Estimates.

1. Investment Tax Credit (ITC)

Form 3468 (Investment Credit).

Solar ITC measure: use the solar component credit lines on Form 3468 (not basis). For example, for TY2008:

- Part II solar: line 5b (solar illumination/solar energy × 30%)
- Part III solar: line 11b (solar illumination/solar energy × 30%)
- Construct: Solar_ITC_{2008} = amount(5b) + amount(11b) (both are credit amounts as reported on the form; amounts are in thousands).

2. Production Tax Credit (PTC)

Form 8835 (Renewable Electricity Production Credit).

Total PTC measure: use the total credit carried forward on the form, which includes electricity production credit (by resource where available), refined coal/Indian coal/other Form 8835 components (small share in many years), pass-through credits (credits allocated from partnerships/S-corps/etc.), reductions for government grants, subsidized financing, and other credits.

Construct (by form version):

- Modern forms (e.g., TY2022): Total_PTC = line 20 (line 18 + line 19; includes adjustments/reductions and pass-through).
- Older forms (e.g., TY2008): Total_PTC = line 10 (Part I) + line 36 (Part II) as the amounts reported onward to Form 3800.

B.4 Table 1

Reconstructions of capital costs and the stacked public subsidies for two early-2010s utilityscale projects—panel (a) the Agua Caliente solar PV project (Yuma County, AZ) and panel (b) the Shepherds Flat wind project (Gilliam and Morrow Counties, OR)—combine public filings (DOE, CPUC, SEC, and court documents) with NREL/DOE technical benchmarks, supplemented by structured modeling where key values are not directly observable. All present values are reported at the project's financial close. The two projects use different discount rates, each based on a contemporaneous, sponsor-specific corporate borrowing benchmark.

(a) Solar: Agua Caliente (290 MW)

Discount rate. All present-value calculations use a 7.85% discount rate, a principal weighted average of selected NRG Energy's corporate bonds issued in 2010-2011 (https: //companiesmarketcap.com/nrg-energy/sec-reports-10k/0001445305-12-000493/). Present values are stated at the August 2011 financial close.

Cost structure. Total project cost is anchored at ≈ $1.8 billion. Because no fully public cost breakdown exists, individual components (land acquisition, site preparation, modules, inverters, labor, and other qualified costs) are reconstructed from NREL utility-scale PV benchmarks for First Solar CdTe fixed-tilt technology. The project is balance-of-system–dominated rather than module-dominated, and land costs are negligible (<1%). The residual (financing, development, and other non-ITC-eligible costs) is the difference between total cost and the sum of ITC-qualified components.

Subsidies.

- *Investment Tax Credit (ITC):* Observed at $465.5 million.
- *Accelerated depreciation:* Modeled as the timing value of 5-year MACRS plus 50% bonus depreciation relative to a 20-year straight-line counterfactual, at a 35% federal corporate tax rate and the 7.85% discount rate. The ITC basis-reduction rule (basis reduced by one-half of the credit) is applied.
- *DOE loan guarantee:* The observed $967 million of DOE-guaranteed debt (https:
- //www.energy.gov/edf/agua-caliente, issued through the Federal Financing Bank at Treasury + 37.5 bps, non-recourse) combined with an average DOE solar-program credit-subsidy rate of ≈11.7% gives $113.1 million.
- *RPS/PPA premium:* Output is sold under a 25-year PG&E PPA (expected generation ≈ 688 GWh/yr). PPA premium uses a non-official contract-price proxy of $147.50/MWh from later CPUC-filed testimony, which was explicitly found above market; the original Agua Caliente contract price in the CPUC approval remains confidential. The premium is estimated as the gap against the CPUC market-price referent benchmark ($132.9/MWh), i.e. ≈ $14.6/MWh, capitalized over the contract term.

Wind: Shepherds Flat (845 MW)

Discount rate. All present-value calculations use a 4.79% discount rate, taken from Brookfield Renewable's February 2012 issuance of C$400 million of 10-year corporate notes (https:

//www.sec.gov/Archives/edgar/data/1001085/000119312514124277/d692712dex991.htm). Present values are stated at the 2012 financial close.

Cost structure. Total project cost is anchored at ≈ $1.9–$2.0 billion. The largest observable component is GE's $1.4 billion turbine-and-services contract; the remainder covers other qualified costs (roads, foundations, electrical work, interconnection) and a residual of development and financing costs ineligible for the Section 1603 grant basis.

Subsidies.

- *Section 1603 cash grant:* The three project entities received a combined $491.6 million, elected in lieu of the PTC.

- *Accelerated depreciation:* Modeled as the timing value of 5-year MACRS plus 50% bonus depreciation relative to a 20-year straight-line counterfactual, at a 35% federal corporate tax rate and the 4.79% discount rate. The depreciable basis is grant basis less one-half of the Section 1603 payment, per the statutory basis-reduction rule; lower-bound $137.7 million.
- *DOE loan guarantee:* The observed $1.3 billion DOE partial loan guarantee: https://www.energy.gov/lpo/shepherds-flat combined with an ex ante credit-subsidy rate gives $152.1 million.
- *State subsidies (Oregon):* Oregon Business Energy Tax Credit (BETC) plus the Strategic Investment Program (SIP) property-tax abatement, the latter valued by discounting observed annual savings of ≈$10–11 million over the 15-year term at 4.79%.
- *RPS/PPA premium:* Output is sold under three 20-year Southern California Edison PPAs. CPUC confirms above-market costs once firming and shaping are included, but contract prices are confidential; carried at ≈$220 million from contemporaneous public estimates.

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1775 Massachusetts Ave NW
Washington, DC 20036
(202) 797-6000
www.brookings.edu