Tax Policy and Power Sector Decarbonization

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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 (e.g., loan guarantees, grants in lieu of tax credits, state and local policies) and regulations (e.g., 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 (e.g., mobility, heating), this paper focuses on the evolution of tax policy and renewable power technologies to draw insights and lessons for future policy design.

Introduction

In principle, addressing the risks of a changing climate through the tax code could generate substantial fiscal revenues. 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, U.S. Federal policy has employed tax expenditures to subsidize clean energy technologies.

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 (e.g., loan guarantees, grants in lieu of tax credits, state and local policies) and regulations (e.g., state renewable portfolio standards), public policy has contributed to cost-reducing innovation and significant adoption of zero-carbon power generation technologies. What had originally been modest tax expenditures for niche investments at the turn of the century, has evolved in recent years into having significant revenue implications. While characterized by significant uncertainties, the potential tax expenditures of the Inflation Reduction Act (IRA) of 2022, for example, could have exceeded $1 trillion over ten years before its modification in the One Big Beautiful Bill Act (OBBBA) of 2025 (Aldy 2025). However, research suggests that the IRA was not especially cost-effective in reducing greenhouse gas emissions, 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 by 2050, the share of electricity in final energy is predicted to increase to 20–56 % in 2050 compared with 18–25 % 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. Many energy-economic modelling results agree that nearly all light-duty vehicles will be electric by 2050 (Kerry and McCarthy 2021; Bistline 2021). In the building sector, heat pumps, electric heaters and electric cooking will continually replace pipeline gas and electrified heating is predicted to exceed 60% of new sales by 2030 and nearly 100% by 2050. Electricity's share of building final energy rises from about 50% in 2020 to 90% or more by 2050, dramatically changing the overall energy system.

Under a net-zero by 2050 scenario explored by a large set of models in a recent Stanford Energy Modeling Forum exercise, total electricity generation in the United States could double its 2025 quantity of 4.43 trillion kilowatt-hours (kWh) by 2050 (U.S. Energy Information Administration 2026; Gao et al. 2025). Installed power generating capacity would increase from about 1,300 gigawatts (GW) today to about 3,300 GW in 2050, with approximately 90 percent of the increased capacity coming from renewable sources of power (2025). Both the generation and capacity estimates, however, vary significantly among models and are characterized by significant uncertainty. The carbon dioxide emission intensity of the U.S. power sector under this net-zero scenario would likely fall 70% to as much as nearly 100% compared to current intensity levels.

But there is another major force at work as well: the growth of generative artificial intelligence (AI). The corresponding growth in data centers used for generative AI and other purposes is already spurring substantial growth in electricity use. U.S. electricity use was the highest ever in 2025, and according to the U.S. Energy Information Administration, should exceed this in both 2026 and 2027.[1] This additional electricity demand will raise prices, incentivizing all generation, but it also will put further strain on the electricity grid, potentially exacerbating reliability concerns unless there are considerable investments to improve reliability.

The goal of this paper is to clarify how the tax system has been used to influence the adoption of clean electricity generation and to discuss the market failures and other barriers that play a role in the electricity market. We focus on the evolution of tax policy relating to clean electricity and what it means for the economics of clean electricity. Indeed, as was just discussed above, 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 externalities. The first-best or Pigouvian approach to reducing negative externalities from pollution is to tax the polluting activity at the level of the damages to society. By subsidizing clean electricity, there is immediately a distortion in that the subsidy lowers the equilibrium market price of electricity and inefficiently increases electricity consumption. Of course, there may be other market or regulatory failures that counteract and raise the price of electricity, and indeed, evidence has shown that electricity is often priced above the marginal social cost that accounts for the costs of pollution and other externalities (Borenstein and Bushnell 2022). But even conditional on subsidizing clean electricity, the tax expenditures in many cases may not be well targeted. This may lead to lower cost-effectiveness (i.e., higher costs per ton abated) and thus greater tax expenditures to reach any given climate goal.

There are also important interactions among various policies governing the power system. For example, different clean energy subsidies could serve to complement each other, but in some cases may render other policies focused on clean energy as less relevant. For example, if clean energy tax credits are sufficiently generous, some state Renewable Portfolio Standards, which require a certain percentage of electricity generation by each utility to be from renewables, may become irrelevant because enough renewables are installed anyway. A carbon tax could also interact with clean energy tax policies by raising the price of fossil fuels relative to clean energy, thus incentivizing clean energy. There are also interactions between tax policy and other frictions or imperfections in current institutions. We call these “shadow costs” or “hidden costs”

[1] See US power use to beat record highs in 2026 and 2027 as AI use surges, EIA says

and they include challenges due to the interconnection queue (i.e., the queue formed by potential generators that wish to interconnect to the electricity grid), facility siting and permitting, imperfect competition, and suboptimal reliability standards and requirements. All of these factors slow the adoption of clean energy, and reforms reducing these barriers would be expected to interact with subsidies or a carbon tax to increase clean energy adoption.

1 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 employed 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 over time, 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 compare and contrast the key attributes of current renewable technologies with current fossil fuel technologies.

1.1 Major Trends

The U.S. electric power sector capacity has increased from about 800 GW to more than 1300 GW over 2000-2025 (see Figure 1). During this time period, coal capacity fell almost in half, as natural gas capacity increased.

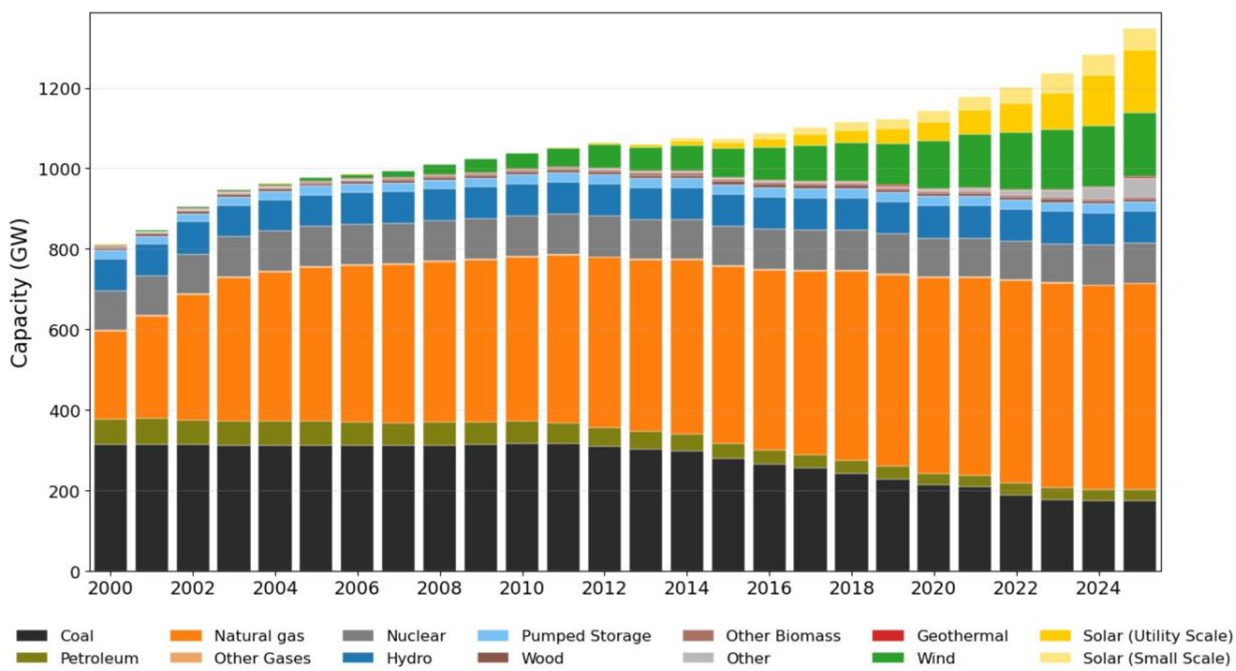

Figure 1: U.S. Electric Power Sector Net Summer Capacity, by Technology, 2000–2025 (gigawatts)

Image description: Bar chart showing US electric power sector capacity by technology from 2000 to 2025, illustrating the decline of coal, the growth of natural gas, and the rapid expansion of wind and solar.

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 the capacity factor (i.e., the ratio of a plant's actual output to its maximum potential output) of renewables can be much lower than heavily-used combined cycle natural gas or coal plants. The average capacity factor for solar power plants is about 25% and for wind power it's about 35%.[2] 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 declining 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 falling at a slower pace. Some of the decline in module prices reflects innovation induced by deployment subsidies like the ITC (Gerarden 2023).

The middle panel of Figure 2 shows cost trends in utility-scale solar, which largely mirror the trends over time in residential solar. The installed costs of utility-scale solar are significantly lower than residential solar, and are very close to being on-par with onshore wind (middle and bottom panels of Figure 2).

The bottom panel of Figure 2 reveals the trend in onshore wind's costs that differ significantly from the two panels for 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 over the past two decades.

[2] See EIA resources at https://www.eia.gov/todayinenergy/detail.php?id=39832 and https://www.eia.gov/todayinenergy/detail.php?id=52038.

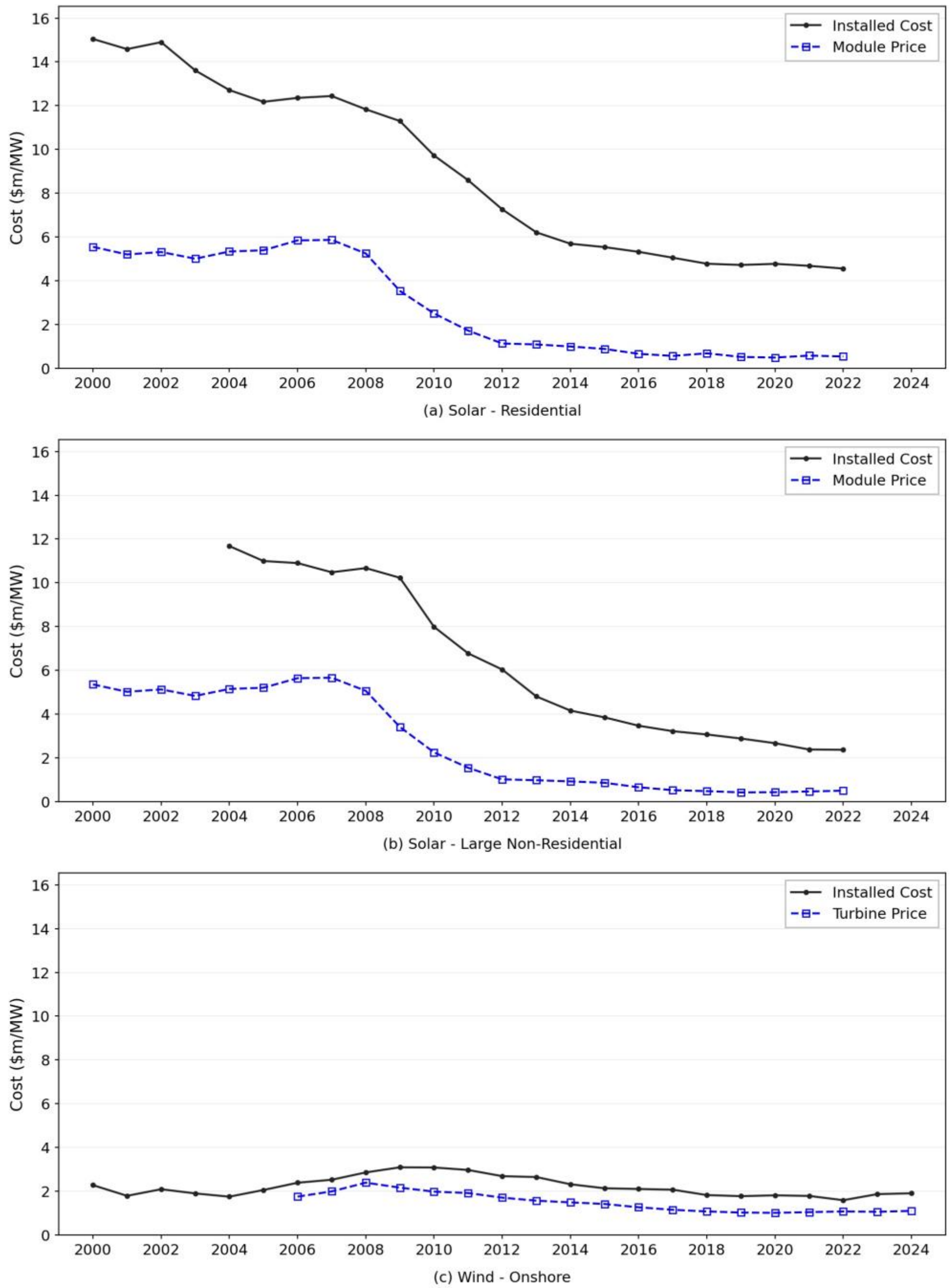

Figure 2: Prices for Solar and Wind Power, by Installed Project Capacity and by Module/Turbine, 2000–2024 (2025$/Megawatt)

Image description: Line chart with three panels showing that installed costs for residential solar, utility-scale solar, and onshore wind have all fallen significantly since 2000, driven largely by declining module and turbine prices.

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 balanceof-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 technologies have realized increasing capacity factors over the past decades (Figure 3). While the 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 utilize 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).

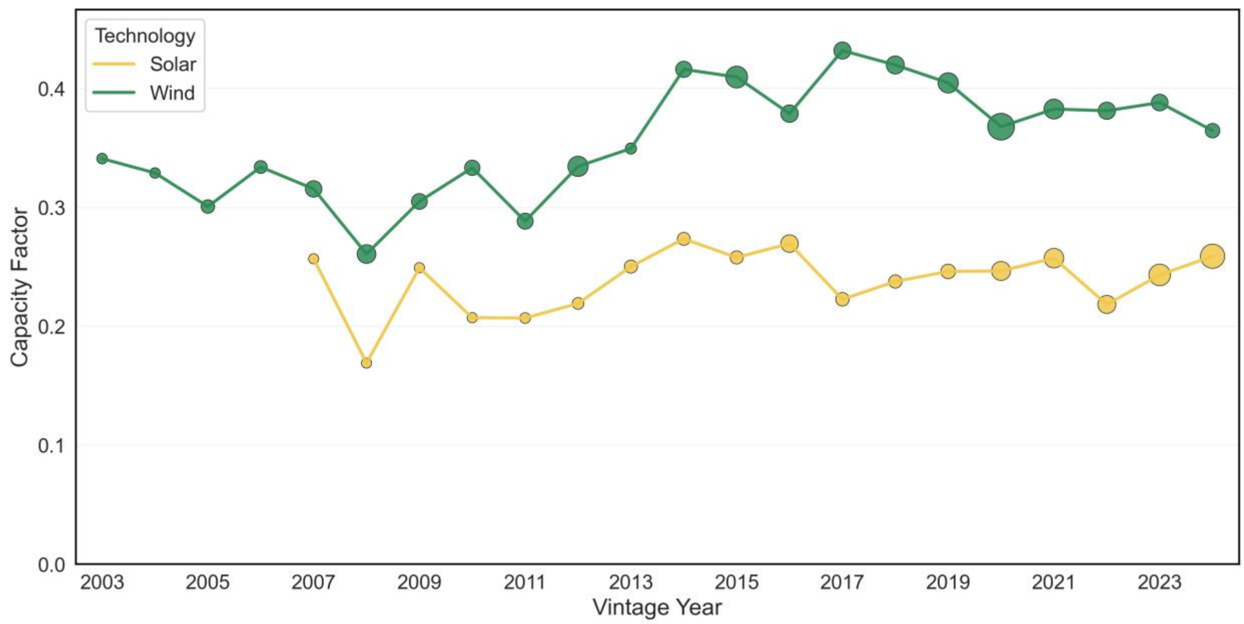

Figure 3: Capacity Factor for Solar and Wind Power Technology by Vintage Year

Image description: Scatter plot showing capacity factors for solar and wind power by vintage year, with wind trending upward over time while solar remains more stable.

Notes: 1. Capacity factor is capacity-weighted for projects of vintage year *t* in year *t* + 1. 2. The size of dots indicate total generation (MWh) by each vintage in their first full year. 3. These are "first full year" capacity factors calculated as the capacity factors for the first full year of operation of the technology. 4.
Data source: EIA Form 860 and Form 906/920/923.

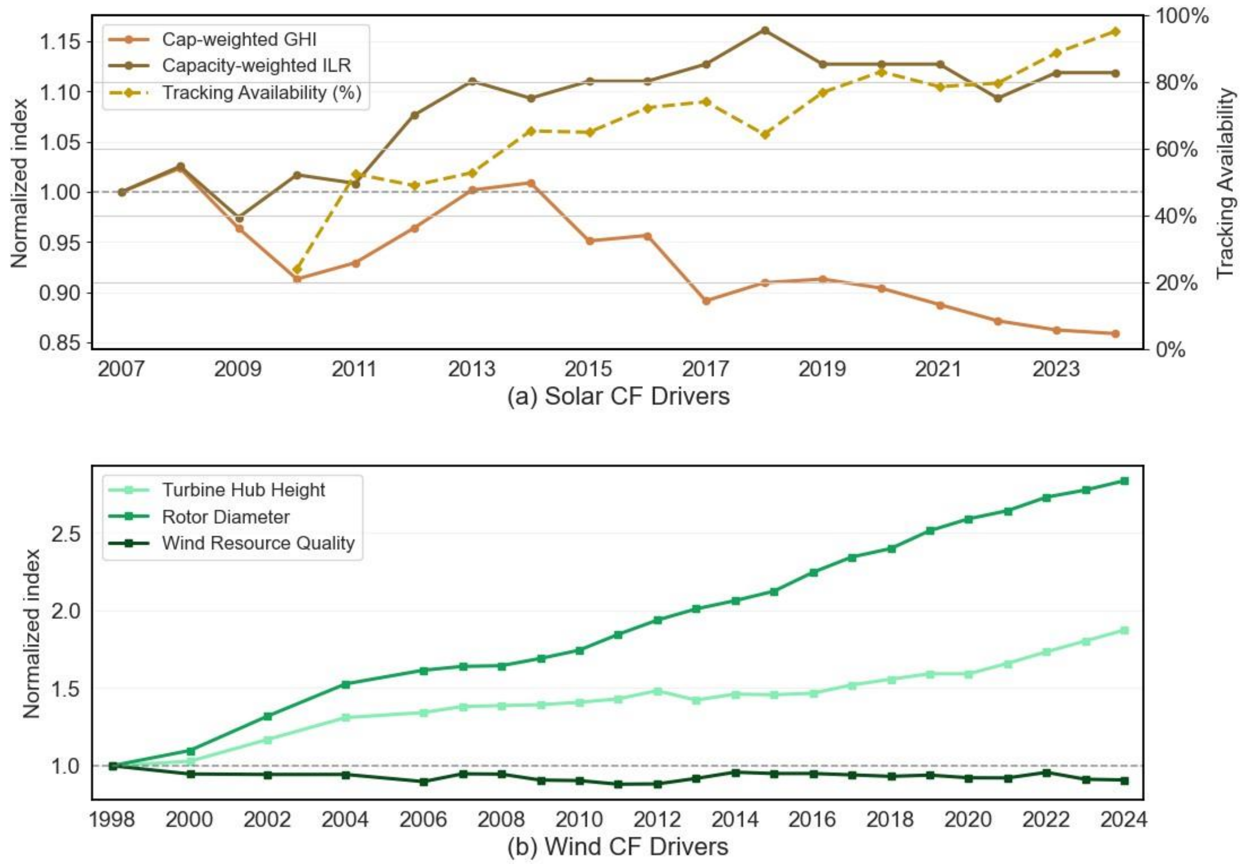

Figure 4: Capacity Factor Drivers for Solar Power and Wind Power

Image description: Two-panel chart showing the drivers of capacity factors for solar and wind power, with wind gains driven by taller turbines and larger rotors, and solar gains from tracking technology partially offset by declining site quality.

Notes: 1. Data source: LBNL. 2025 Utility-Scale Solar Data Update and Land-Based Wind Energy Technology Update 2025 Edition. 2. The indices are calculated by normalizing the earliest year for each technology, i.e. 2007 for solar and 1998 for wind, as 1. Tracking availability is plot 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 for solar and wind power have fallen below that 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 higher than coal-fired power or combined cycle gas-fired power plants.

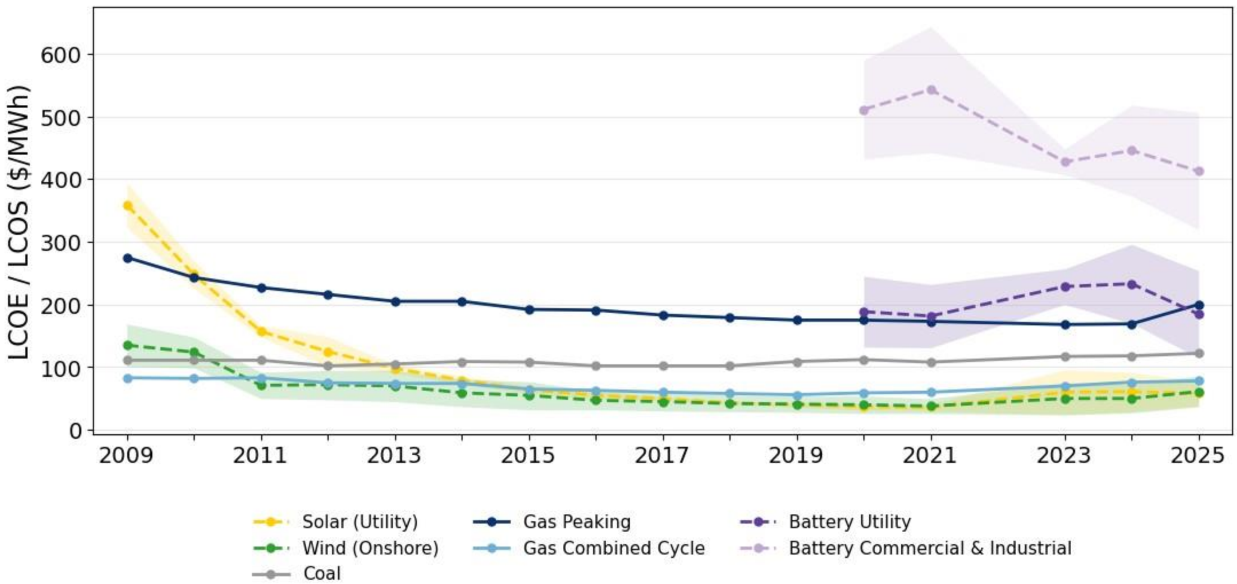

Figure 5: Levelized Cost of Electricity, by Technology, 2009–2025 (2025$/MWh)

Image description: Line chart showing that the levelized cost of electricity for solar and wind has fallen substantially since 2009, now below that of coal and combined cycle natural gas.

Notes: 1. Data source: Lazard, "Levelized Cost of Energy Analysis". All values already expressed in 2025 USD. 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, the solid lines show the average estimates.

1.2 Theoretical Foundations and Practical Policies

There is strong theoretical foundation that advocates for policy support for clean technologies. Environmental externalities motivates 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 R&D. These factors also make innovation path dependent, (Acemoglu et al. 2012; Aghion et al. 2019), and therefore policy delay is consequential. The existence of other market failures such as financing frictions and coordination problems also justifies policy intervention in the clean technology space (Armitage et al. 2024). Given the multidimensional market failures, a portfolio of policies is likely to be more cost-effective than any single instrument (Fischer and Newell 2008).

In practice, a varying 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-andcontrol regulations (Joseph E. Aldy et al. 2022). Tax related policies, including production tax credits (PTC) and investment tax credits (ITC), have been the most salient renewable energy policy in the United States. Figure 6 presents the timeline of the evolution of 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	—	Energy ITC: 10% (business solar)
1986 Tax Reform Act of 1986 (MACRS / §168)	—	—
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 (12/18/2015) (multi-year extensions + phase-down design)	Extended to BOC before 2020 with phase-down: 80% PTC for BOC in 2017 & PIS before 2022 60% PTC for BOC in 2018 & PIS before 2022 40% PTC for BOC in 2019 & PIS before 2022 60% PTC for BOC in 2020 & PIS before 2022 60% PTC for BOC in 2021 & PIS before 2022	30% ITC extended through 2019 (BOC); stepdown schedule
2020 Taxpayer Certainty and Disaster Tax Relief Act (12/20/2019)	—	26% ITC if BOC in 2020 and PIS before 1/1/2024
2021 Consolidated Appropriations Act 2021 (12/27/2020)	—	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

Policy milestones	PTC	ITC
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. Green shading indicates credits applicable to wind (PTC column). Yellow shading indicates solar (ITC column). 2. Projects are categorized by two criteria: BOC – beginning of construction and PIS – placed in service. 3. Explicit credit values are for facilities with capacity > 1 MW; higher rates have been available for smaller facilities.

Image description: Timeline table showing the evolution of the production tax credit and investment tax credit for renewable power from 1978 to 2025, including key legislative expansions and the recent restrictions under the 2025 One Big Beautiful Bill Act.

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 to $20 billion annually over the past decade, reflecting significant policydriven 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 in order 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 over time. With an ITC, there are countervailing forces – growing capacity would, ceteris paribus, increase tax expenditures, but falling investment costs per unit capacity could offset this effect (Aldy 2025). The experience with the Section 1603 grant illustrates how freeing project developers of the need to attract tax equity was attractive to many solar and wind developers, as they opted for the 1603 grant (2013). This informed the Inflation Reduction Act provisions to enable developers to transfer their tax credits, which reduces the transaction costs of monetizing the value of tax credits (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 (Joseph E. Aldy et al. 2023).

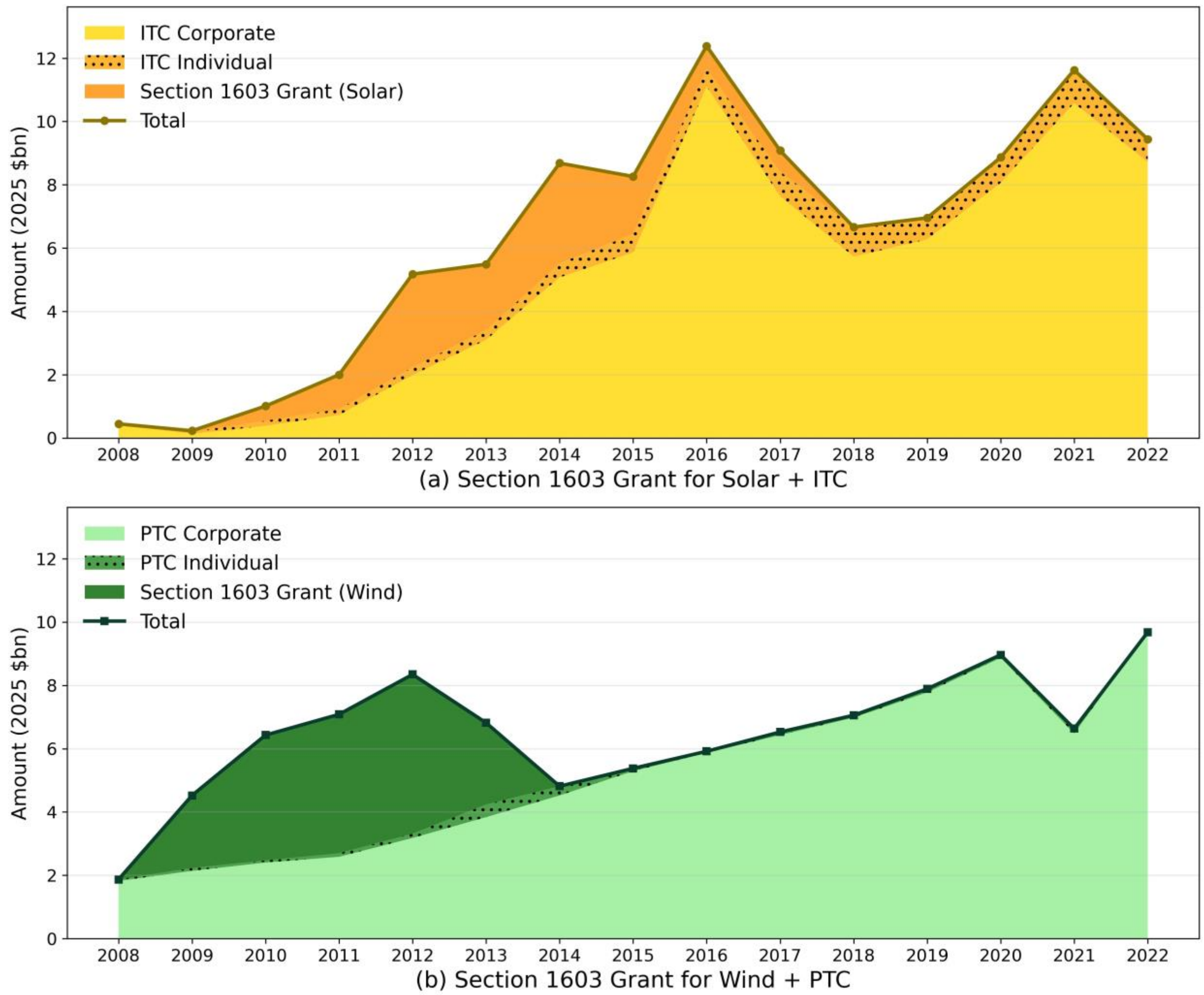

Figure 7: Federal Tax Expenditures for PTC and ITC, 2008–2022

Image description: Two-panel area chart showing federal tax expenditures for solar ITC and wind PTC from 2008 to 2022, with both rising over time and notable spikes tied to policy deadlines.

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.

1.3 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 the tax expenditures described above. To illustrate the extensive bundle of implicit and explicit subsidies, Table 1 summarizes the key economics of Agua Caliente, what was the largest U.S.

solar power facility at the time it was placed into service starting in 2011 (Panel A) and Shepherds Flat, what was the largest wind farm in the country at the time it was placed into service in 2012 (Panel B). Ague 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 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 investment costs of $1.9 billion 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 of these cases, and many other utility-scale renewable power projects, the tax code delivers substantial subsidies, but 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	12.06
	Site-preparation	54.00
	Module	918.00
	Inverter	144.00
	Labor	252.00
	Other qualified-cost	171.46
	Residual cost ineligible for ITC	248.48
Total Cost		1800.00
Subsidy		
	Investment Tax Credit	465.45
	Accelerated depreciation	172.80
	DOE loan guarantee	113.10
	RPS/PPA premium (California)	88.70
Total Subsidy		840.05

(b) Wind: Shepherds Flat

Category	Component	Present Value at 2012 Close ($m)
Cost		
	GE turbine + service contract	1400.00
	Other qualified-cost	238.50
	Residual cost ineligible for grant basis	261.50
Total Cost		1900.00

Subsidy		
	1603 cash grant	491.50
	Accelerated depreciation	137.70
	DOE loan guarantee	152.10
	State subsidies (Oregon)	123.40
	RPS/PPA premium (California)	220.00
Total Subsidy		1124.70

Note: See Appendix B for assumptions and calculations.

The generation mix of electric power varies significantly across the nation (Figure 8). For example, the Pacific Census division generates nearly 60% of its electricity from hydropower, solar, and wind facilities. Wind power makes up 37% of the power generated in the West North Central Division, and solar power makes up more than one-fifth of the power in the

West South Central Division. Renewable power plays a less significant role in the East South Central, South Atlantic, and Mid Atlantic Divisions, where natural gas and coal dominate the generation mix. This spatial heterogeneity highlights the potential for incremental renewable power investment to vary significantly in the type and emissionsintensity of the power generation it may displace in a given market.

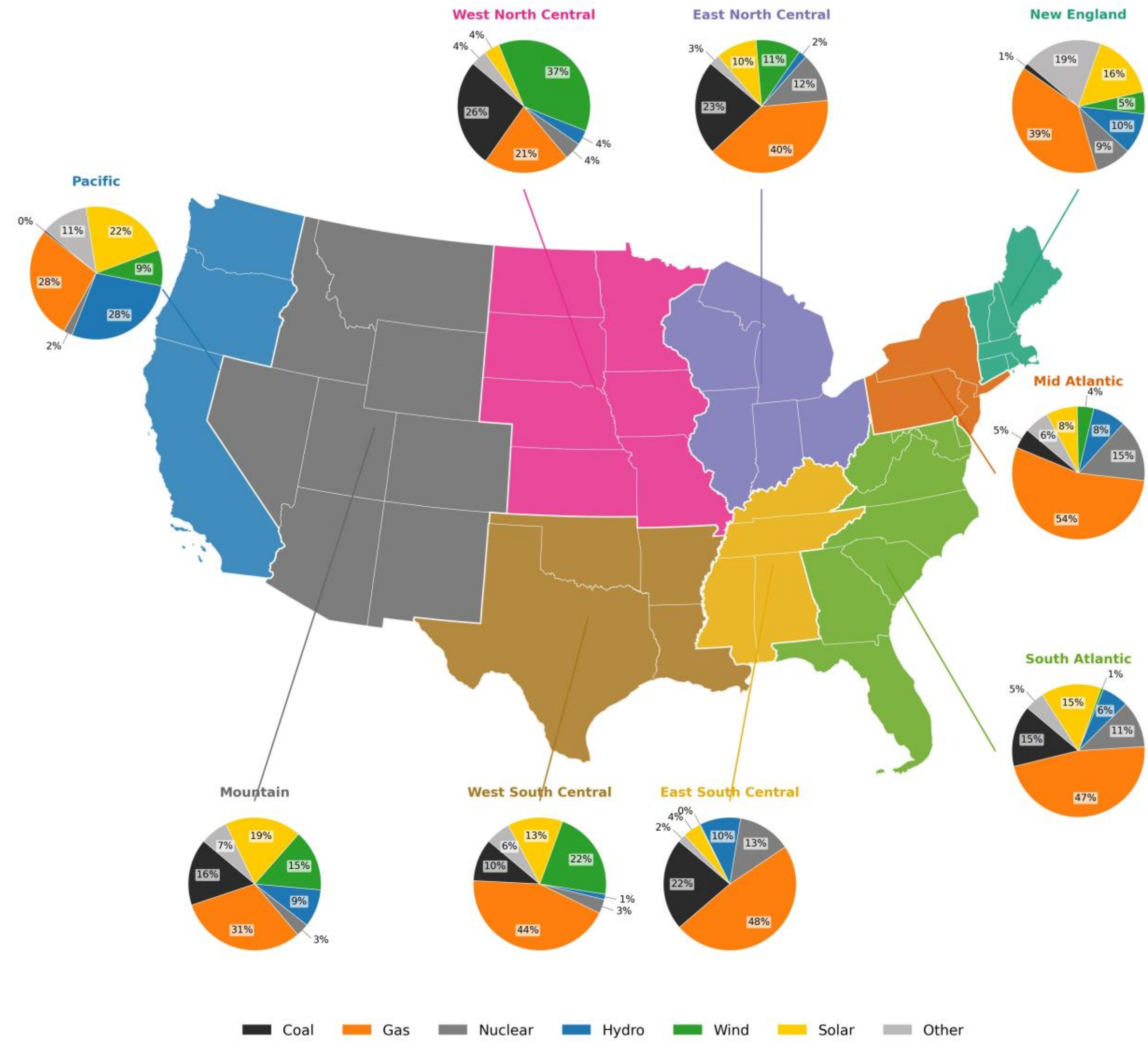

Figure 8: Geographic Heterogeneity in Installed Power Capacity, 2025

Image description: U.S. map with pie charts showing the electricity generation mix by census division in 2025, highlighting significant regional variation between renewables-heavy western regions and fossil-fuel-dominant eastern and southern regions.

Notes: 1.Generation in Alaska and Hawaii is included in Pacific though the areas are not plotted for compact layout.

1.4 What we Know from the Literature

Empirically, a growing literature studies whether, and through which channels, policies can stimulate clean technology *innovation*, accelerate *cost reduction*, and increase *adoption*. While our ultimate goal is to inform U.S. policymaking, the available U.S.-based evidence is limited in several important areas. Accordingly, we take a broader view and 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 centering 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 EU ETS 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 PV output, innovation, and productivity, with especially large effects when production subsidies were paired with R&D support. The most effective policy may vary for different technologies (Johnstone et al. 2010).

A second strand of the literature focuses more directly on cost reduction. Here, the evidence is thinner, but it points to the importance of dynamic effects such as learning-bydoing (i.e., 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) focuses on the technology and studies solar markets in Germany, Japan, the United States, and the rest of the world over 2010–2015, he 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 government policy in accelerating cost declines in EV batteries through learning-by-doing, showing that the effectiveness of consumer EV subsidies depends in part on their dynamic impact on production experience and cost reductions over time. More broadly, this literature suggests that policies should not be evaluated solely on static deployment effects, because their long-run value may depend on how much they accelerate cumulative production, learning, and future cost declines.

A third strand emphasizes adoption and the design of deployment incentives. De Groote and Verboven (2019) study residential solar 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, 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 same point emerges in the comparison of investment- and output-based subsidies for wind. Joseph E. Aldy et al. (2023) show that, in the United States during 2005–2012, the Production Tax Credit induced more electricity generation than the Section 1603 grant in lieu of tax credit and was substantially more cost-effective, with the PTC delivering a given amount of wind generation at roughly 28 percent lower cost. Relatedly, Abajian and Pretnar (2024) show that residential solar subsidies increase rooftop adoption but do not fully displace grid electricity consumption, cautioning against interpreting deployment onefor-one as emissions reduction. Finally, Borenstein and Davis (2025) highlight that the incidence of clean technology subsidies is highly uneven, with tax credits for technologies such as EVs, heat pumps, and solar panels disproportionately benefiting higher-income households. This suggests that even when subsidies stimulate adoption, their distributional consequences may be important for policy assessment.

Taken together, the literature delivers three broad lessons. 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 backloaded 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. Any assessment of climate and energy policy should therefore account for both static deployment effects and these longer-run dynamic impacts.

2 Targeting the Emissions Externality through Tax Policy Instruments

A standard policy prescription for addressing a negative externality, such as the emissions of carbon dioxide, 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 decision-maker 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.[3]

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

[3] An analogous decision-making process will hold under market-based regulatory approaches that implement cap-and-trade programs.

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 on existing incumbents. Likewise, as we describe below, 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 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 in a much lower tax per kilowatt-hour of generation as coal plants. Indeed, an efficient combined cycle natural gas may emit about half the carbon dioxide per kilowatt-hour of generation as a conventional coal plant, and thus bear a much lower tax per generation while facing the same tax per ton of emissions. This can spur both improvements in generation efficiency –
i.e., 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 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 conservation behavior and investments in energy efficiency among electricity consumers. This serves to create another opportunity for reducing emissions, by reducing power demand through the enhancement of the productive use of electricity in delivering energy services. 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 across 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 utilization of emission-intensive sources, and increased utilization 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 efforts and investment in more energy efficient equipment and technology. It would drive innovation towards 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 in response to the tax.

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 in shaping public policy. 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 over the past year or so.

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 outcome as a tax on the negative externality (Baumol and Oates 1988; Joseph E. 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 sub-optimal incentives to a carbon tax.

As noted above, 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 2008 and in 2016 (as well as every year in between), despite the fact that the cost of a solar panel fell more than 80% over that time period. Given that other categories of investment costs did not fall meant that the subsidy per kilowatt of capacity did not change 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 time period when the estimated social cost of emitting carbon dioxide was increasing in formal policy analyses (Joseph E Aldy et al. 2021). As a percentage of investment costs, the implicit subsidy per kilowatt-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 mid-day through mid-afternoon. In some markets, this could reduce dispatch of natural gas-fired power, and in other market 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 kilowatt-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 emissionintensive 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.

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, states with utility-scale wind and solar investment in 2023, the marginal intensity of displaced power generation varied from 0.44 tCO_2/MWh in New York to 0.76 tCO_2/MWh in Colorado for wind, and 0.46 tCO_2/MWh in Florida to 0.76 tCO_2/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.

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 new build of 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. footnote: In the Inflation Reduction Act of 2022, Congress established the first technology-neutral ITC and PTC for the power sector.

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 (Joseph E. Aldy et al. 2023). In most U.S. markets in which the emissions externality from fossil fuels remain 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. With the exception of this distinction, however, the PTC has very similar properties as the ITC when it comes to comparing 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 nuclear power plants, which produced minimal marginal carbon emissions.

A carbon tax represents a national tax law that 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, a tax expenditure for new renewable power generating sources do not have the same energy system wide incentives and impacts. Some regions may have poor solar and/or wind resources, and thus experience very little incremental investment under these tax expenditures. Some regions may be 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.

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 an effectively 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 they are indirect approaches to reducing emissions in that these tax expenditures 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.

3 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 sub-section, 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 sub-section, we describe reforms to various power sector regulatory regimes that impose higher than necessary costs on new renewable power development.

3.1 Enhancing the Cost-Effectiveness of Renewable Power tax Expenditures

Historically, clean energy tax credits in the power sector have typically been technologyspecific and externality-neutral. I.e., they have identified specific qualifying technologies (e.g., 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 (e.g., 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 those for projects satisfying specific wage and apprenticeship conditions (a tax code analogue to Davis-Bacon Act provisions for spending programs), employing a minimum of American-manufactured components, as well as placebased bonuses for locating in energy communities.[4]

[4] 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.

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). Given the geographic variation in emission intensity in the U.S. power system, only the placebased 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, 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	$60/MWh	$300/MWh	$330/MWh	$360/MWh
ITC	6%	30%	40%	50%

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 intensity than non-energy communities. Thus, these provisions that conditioned the magnitude of tax expenditure value by the characteristics of the project did not do so in a way that more effectively targeted the emissions externality.

There is an earlier precedent, however, for conditioning tax credits on characteristics of the energy system. Specifically, the 2015 Omnibus extending the PTC for wind included an adjustment to the value per megawatt-hour based on a reference price calculated by the Treasury Department of the annual average contract price for wind power sold in the preceding year. If this average contact price exceeded the reference price, 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, one could create a PTC schedule that adjusts as a function of the marginal emission intensity of the relevant market in the preceding year (such as described in the previous section using U.S. Environmental Protection Agency (2026)). Defining the relevant market could be determined by the state or the market (e.g., 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 preceding year, the tax code could encourage investment in more emission-intensive areas and spur earlier entry into these areas (i.e., 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 + 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 the taxpayer 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 time period. The balance 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 initial capital investment (2023). These output incentives leveraged opportunities for learning, adjustment, and maintenance of wind farms to enhance their output. Focusing future subsidies on output would 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 ten years under the PTC.

It's 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 entered into partnerships with financial institutions that would provide the service of monetizing the tax credit by supplying socalled tax equity: the financial institution makes an equity investment and it retained the claims to the project's tax benefits. This service cost projects about 15 cents on the dollar (Johnston 2019). I.e., 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). Any future subsidies for clean power generation should focus on output-based measures that minimize the transaction costs necessary to realize the subsidy.

Let us describe one approach that could realize several objectives: 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 powr tax expenditures. A technologyneutral 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 ten years, with ten, 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 ten-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 claim 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 to enter into financial transactions to monetize the subsidy.

3.2 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 public support through 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 as a result 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 – could enable greater renewables adoption and interact with various tax policy instruments. It is useful to distinguish the categories of shadow costs that stem from policy actions from those that are technological. Most of the shadow costs we focus on are policy-driven and relate to inefficient regulations or policy designs. However, some are technological, 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:

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

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 time period and also push back the revenues to a later date that is discounted at a higher rate. Both will be discussed below.

3.2.1 Interconnection queue

For any planned new power plant or electricity generator, the grid operator must provide approval before the generator can send electricity into the grid. This approval process is the "interconnection" process. Typically it involves an analysis of the costs that would be incurred by the electricity system should the new generator begin feeding in electricity into the grid. 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 needed 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 of 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 years in some regions of the United States (Johnston et al. 2023).

Indeed, the median duration in the interconnection approval process has increased by over 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 12.66% (or 1.57 of one-year revenue). Taking the wind project Shepherds Flat as an example, the two-year delay would cost the 845-MW wind farm, assuming an average capacity factor of 35%, $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 on the interconnection queue is associated with about 65 megawatts less wind power capacity investment per year.[5] This is approximately equal to the difference in queue duration between the PJM and ERCOT markets, on average over 2017-2025, although the difference has increased significantly in recent years.

In February 2022, PJM instituted a pause in accepting new applications in its interconnection queue. The market operator indicated its plan to 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. This occurred, however, after the 2025 OBBBA effectively sunset the tax credits for wind and solar unless they have begun construction by July 4, 2026 and are 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 short, no taxpayer could have initiated from scratch a new renewable power project over the nearly four years of tax credit eligibility under the Inflation Reduction Act in the PJM market.

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[5] 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, ERCOT, MISO, NYISO, PJM, and SPP, as well as for non-ISO southeast and west region regulated markets.

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 the majority of new project requests, 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 are 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 policydriven cost.

3.2.2 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 (i.e., the interconnection queue), and community opposition are the dominant 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) estimates that doubling the recent years' rate of new transmission construction could increase the emission reductions enabled by clean power tax credits under the IRA by a factor of four.

More broadly, permitting has become very tied up 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.

3.2.3 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 empirical evidence in Hausman (2025) aligns with a setting in many other regions in the United State that may also exhibit a similar set of circumstances. 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.

3.2.4 Reliability standards

Renewable power plants are imperfect substitutes for conventional fossil fuel power plants. The 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 available to and reliable for 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 (e.g., 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 heuristics employed by the regulator may fall far short of the cost-minimizing regulatory design (Graf et al. 2026). Indeed, the costs of the reliability standards 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 tend to strongly encourage accompanying renewables 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.

3.2.5 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 the shadow costs are heterogeneous across space—and especially in the extreme case where more stringent regulations coincide with better renewable resources (e.g., California)— these regulatory costs can lead to a misallocation of renewable energy development and thus reduce the cost-effectiveness of tax expenditures.

As mentioned above, 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. There has also been a great deal of discussion about reforming the interconnection process so that it is much faster. This could include performing analyses in batches and simply allocating more resources towards 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.

All of 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 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, one-fifth of all U.S. solar power investment and one-seventh of all U.S. wind power investment occurred in Texas. As regulatory costs fall, a key question is what the necessary tax expenditure would need to be to continue to spur renewable power development.

4 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 factor has been the improving economics of renewable power. Through dramatic technological innovation, reducing costs and increasing productivity of wind and solar technologies, the most common investment in power sector generating capacity over the past five years has been in renewable energy, and most notably wind and solar. Federal tax expenditures have both facilitated deployment and enabled this innovation in zeroemitting sources of power.

Making significant progress in decarbonizing the U.S. economy will very likely require both a much more emission-lean and a much 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 trivial, and it is further complicated by continued additional data center power demands expected to come online in the upcoming years with further advances in generative AI.

But the tax code could play an important role in delivering on this vision of electrification garnering emissions abatement, 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 were nearly all for renewable power rescinded in the OBBBA of 2025.

More broadly, the falling costs of wind and solar power technology highlight the need to address the implicit costs of wind and solar power development under existing regulatory regimes. Focusing policy reforms to lower the fixed costs of permitting and interconnection processes, as well as to ensure more cost-effective implementation of reliability standards and mitigating market power, could enhance the economic viability of more renewable power projects. Moreover, this may allow for modifications of the tax code that could provide lower per unit subsidy sufficient to leverage large renewable power build out.

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A Additional Figures and Tables

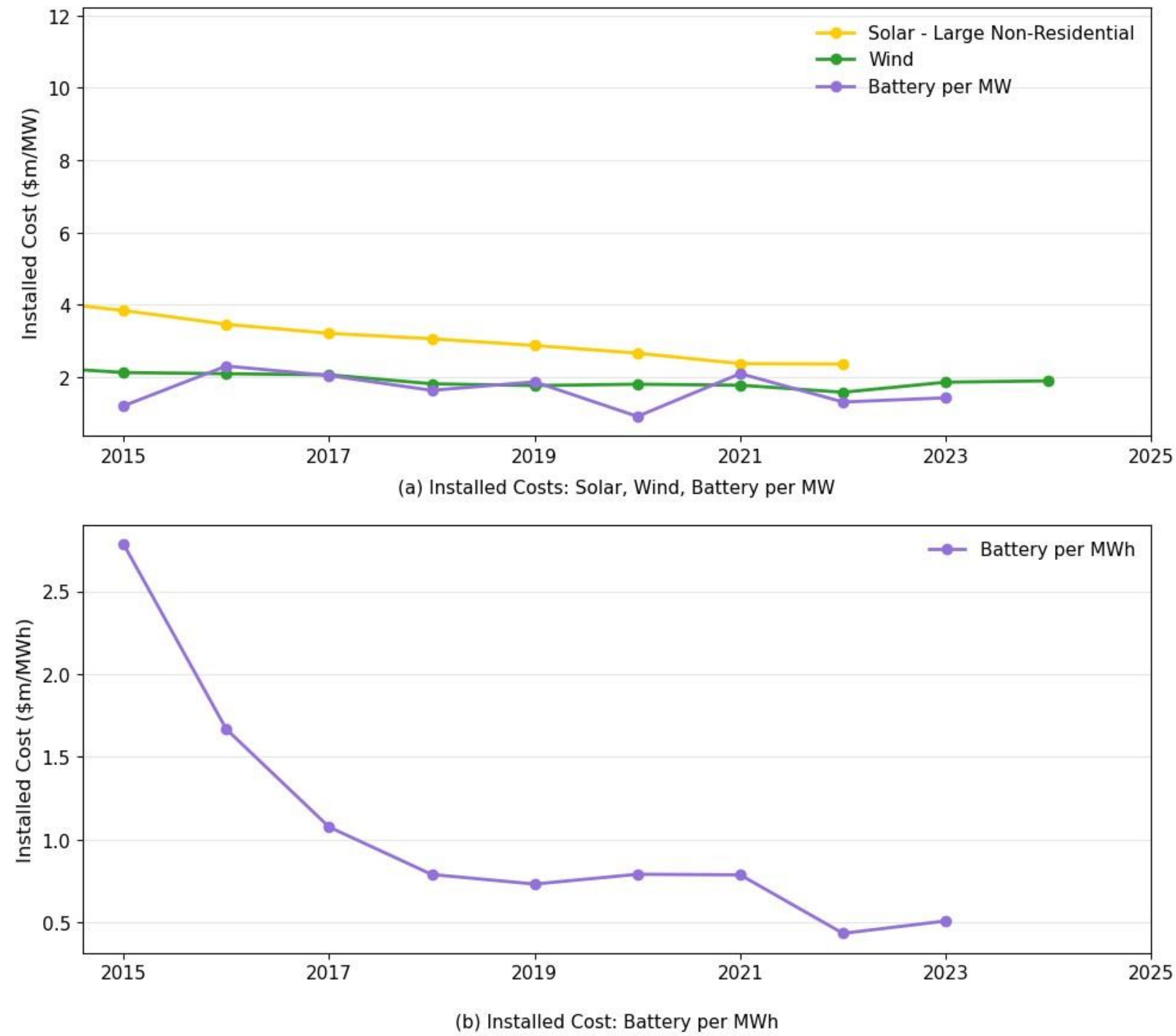

Figure A1: Prices for Battery Storage 2015–2023: per power capacity (MW) and energy capacity (MWh)

Image description: Two-panel chart showing that battery storage installed costs fell sharply between 2015 and 2023, while solar and wind costs per MW remained relatively stable over the same period.

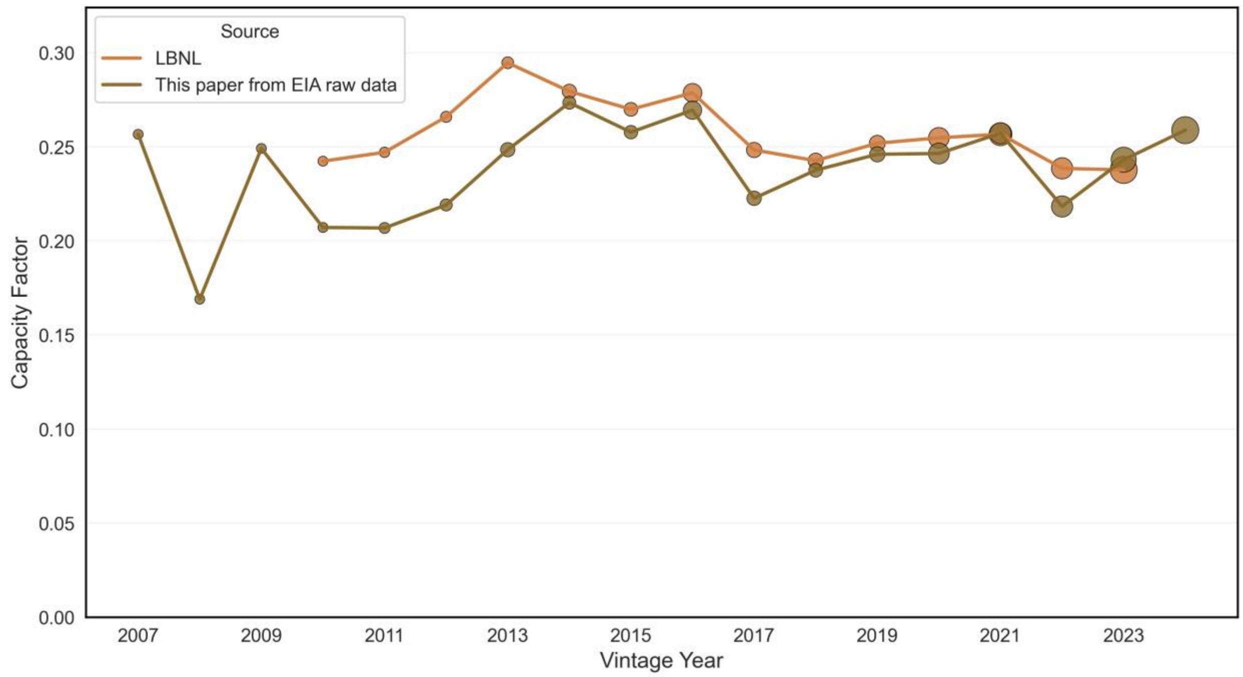

Figure A2: Capacity Factor Comparison: This Paper & LBNL

Image description: Line chart comparing solar capacity factors by vintage year between this paper's estimates and LBNL data, showing the two series track closely over time.

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–

2024. Because 2025 data are not yet available, the 2024 small-scale solar capacity is carried forward to 2025.

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) 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" (accessed on Feb 9, 2026). 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, https://fred.stlouisfed.org/series/GDPDEF, accessed on Feb 9, 2026).

2. Wind (panel c):

   Lawrence Berkeley National Laboratory (LBNL), "Land-Based Wind Market Report: 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). Original values are in 2024 USD/kW; converted to 2025 USD/MW using GDPDEF.

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, taken from NRG Energy's contemporaneous corporate bond issuances: link. 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 abovemarket; the original Agua Caliente contract price in the CPUC approval remains confidential. The premium is estimated as the gap against the CPUC market-pricereferent benchmark (\$132.9/MWh), i.e. ≈ \$14.6/MWh, capitalized over the contract term.

(b) 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: link.

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.