CLEAN ENERGY ISN'T DRIVING POWER PRICE SPIKES

Brendan Pierpont

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SUMMARY

Electricity consumers in the United States are increasingly under financial pressure. Nearly one-third of U.S. households reduced spending on basic needs like food and medicine to pay energy bills during the last year, while nearly a quarter were unable to keep their home at a safe temperature because of concerns about high bills.[1] With electricity costs on the rise, customers face difficult tradeoffs.

Electricity price increases reflect economy-wide inflation. Across the economy, prices have risen by nearly 20 percent since the beginning of 2021.[2] As prices have risen across the economy, so have the rates consumers pay for electricity. With utilities asking their regulators to approve record increases in electricity rates,[3] consumers, policymakers, and other stakeholders are expressing growing concern about impacts on affordability of electricity, a requirement for modern life.[4]

Some observers have argued that clean energy is to blame for rising rates, but the data does not support this conjecture. This report walks through recent trends in electricity rates and unpacks the myriad factors that have contributed to rate increases in recent years, leading to several key takeaways:

- **Evidence does not suggest that clean energy is driving electricity cost increases:** Since 2010, residential electricity rates have not increased faster than inflation, while electricity bills have declined in inflation-adjusted terms. Many of the states with the largest increases in wind and solar generation since 2010—including Iowa, New Mexico, Kansas, and Oklahoma—have seen rates rise slower than inflation.
- **Wildfire costs and risks have significantly increased electricity rates in California:** In California, a clean energy leader, high electricity rates are often wrongly linked to the state's rapid deployment of clean electricity resources. Wildfire-related costs—including grid investments and vegetation management to reduce wildfire risks and insurance costs—have ballooned and now account for 16 percent of the total cost to customers of the state's three primary investor-owned utilities. But California is not alone; across much of the Western U.S., climate change has made wildfires more common and more severe. Colorado, Hawaii, Oregon, and Texas have all seen major wildfire events linked to grid infrastructure in recent years. As climate-related risks accelerate, the cost to electricity customers of mitigating these risks will be critical to address.
- **Natural gas price volatility has been a major driver of higher electricity costs in some states:** Geopolitical uncertainties, extreme weather, and other factors drive significant swings in natural gas prices. Many parts of the U.S. electricity grid are heavily dependent on natural gas, with consumers bearing much of the risk of price spikes.

- **Utilities have made substantial investments in aging, uneconomic coal plants, raising costs to customers:** Coal-fired power plants are increasingly uncompetitive relative to lower-cost and cleaner sources of electricity. Clean energy resources like solar, wind, and energy storage continue to fall in cost, while the cost of maintaining and fueling aging coal plants continues to rise. Against this backdrop, many regulated utilities continue to invest significant amounts of new capital in their coal power plants. Instead of paying off these aging assets as they approach the end of their life, utilities have substantially increased the amount owed on these plants, with customers bearing the costs.
- **Transmission and distribution costs are rising nearly twice as fast as inflation, driven by a focus on grid hardening, resilience, and advanced technology:** Outside of periods of fuel price volatility, electricity generation costs have remained fairly flat, even declining over the long run.[5] However, these cost declines have been more than offset by rising costs of transmission and distribution infrastructure, which have been driven by significant utility spending to replace aging infrastructure, grid-hardening and resilience investments, and investments to support growing demand. Recent transmission investment has not significantly expanded the reach of the transmission system; rather it has focused on smaller, local upgrades. There are opportunities to better optimize this investment to lower costs for consumers, such as by getting more out of the existing grid with grid-enhancing technologies and reconductoring of existing transmission corridors to expand capacity.
- **Regulated utility profit margins and bias toward capital investments underly rising electricity rates:** Utility business models allow utilities to earn a regulated rate of return on capital investment, while generally recovering operating expenses without a margin. This model incentivizes utilities to maximize capital investments, select solutions to grid needs that involve large capital investments over those that involve operational expenses (even when they are more expensive for customers), and maximize the regulated profit margin authorized by their regulators.

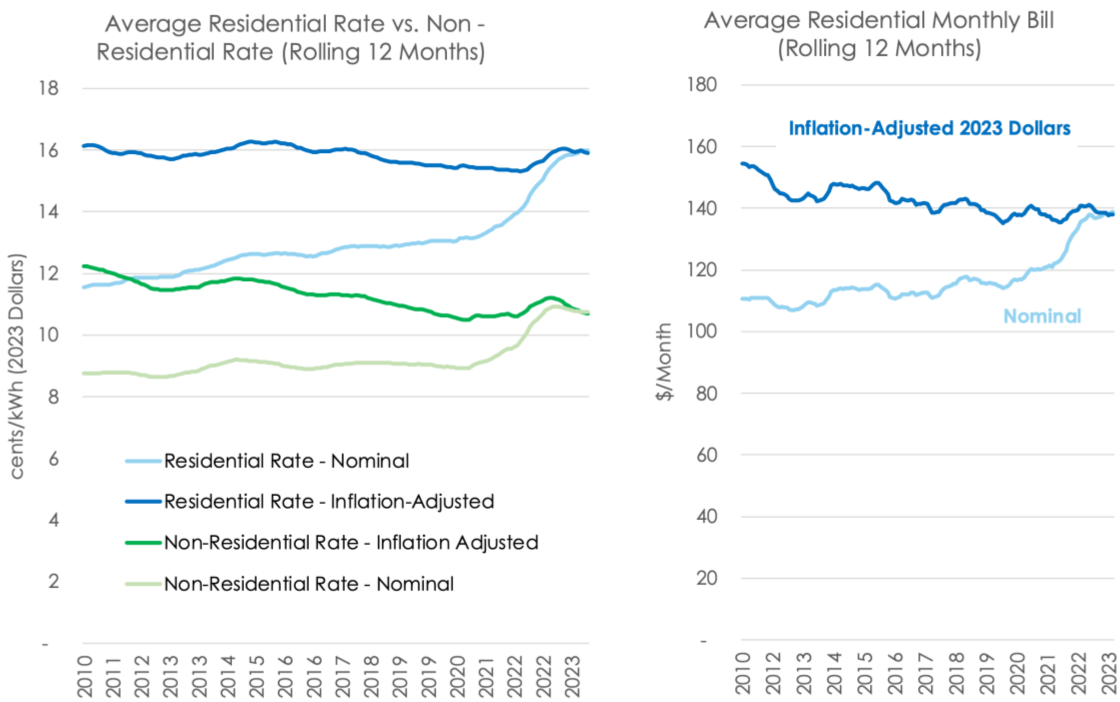
ELECTRICITY RATE AND BILL INCREASES ARE IN LINE WITH ECONOMY-WIDE INFLATION

Since 2010, the average U.S. residential customer has seen electricity rates increase by nearly 40 percent.[6] But in the same 13 years, the Consumer Price Index (CPI), a measure of prices of goods and services across the economy, has also risen by 40 percent. In other words, residential electricity rates have, in aggregate, kept pace with economy-wide inflation.

However, increases in average rates per kilowatt-hour (kWh) of consumption do not tell the whole story. Investments in energy efficiency and distributed energy resources from households, bolstered by policy and utility programs, have significantly reduced household electricity consumption over the same period. This drop in consumption from energy efficiency, and to a lesser extent rooftop solar, helps to dampen the impact of rising rates on overall utility bills. Relative to the 40 percent increase in electricity rates and overall inflation, the average U.S. electricity consumer has seen bills rise by only 24 percent since 2010, a rate significantly lower than inflation. Nonetheless, rising electricity bills put significant pressure on the affordability of electricity, particularly for low-income customers, who spend upwards of 8 percent of their household income on electricity bills, increasing the importance of policies and programs that ensure energy affordability.[7]

While residential customers have seen prices rise at a rate similar to inflation, price increases have been slower for commercial and industrial customers. In contrast to the 40 percent increase in prices experienced by residential electricity customers, non-residential customers saw prices rise by 23 percent on average from 2010 through 2023. In some states, the difference between residential customers and other customers is particularly stark. In West Virginia, for instance, residential rates have risen more than twice as fast as rates for other customers.

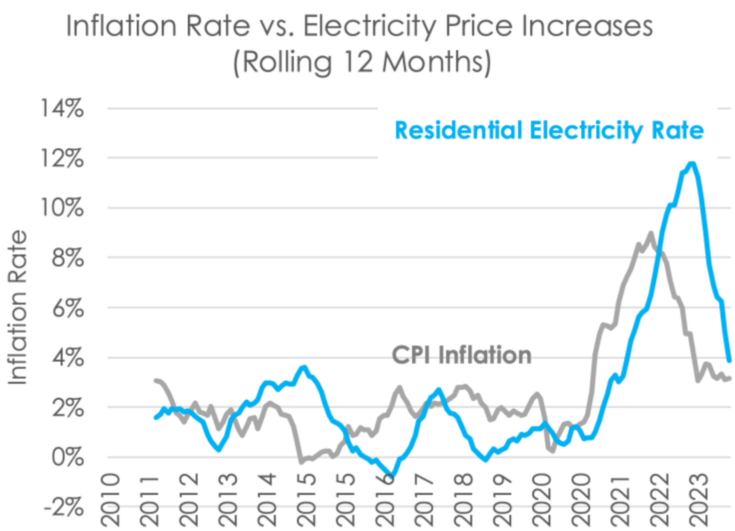
Figure 1. Average U.S. residential electricity rates and bills



Source: EIA 861M, Federal Reserve

While the long-run trend shows electricity rates keeping pace with inflation, the road has not been perfectly smooth. Sometimes, electricity rates have increased more quickly than inflation, while at other times they have grown more slowly. Between 2015 and 2021, residential electricity rates generally grew more slowly than inflation, and it wasn't until 2022-2023 that this gap closed. Also notable, while inflation peaked at a 9 percent annual rate in mid-2022, the pace of electricity cost increases didn't peak for another year, in mid-2023, as rising costs worked through the regulatory process to land on customer bills.

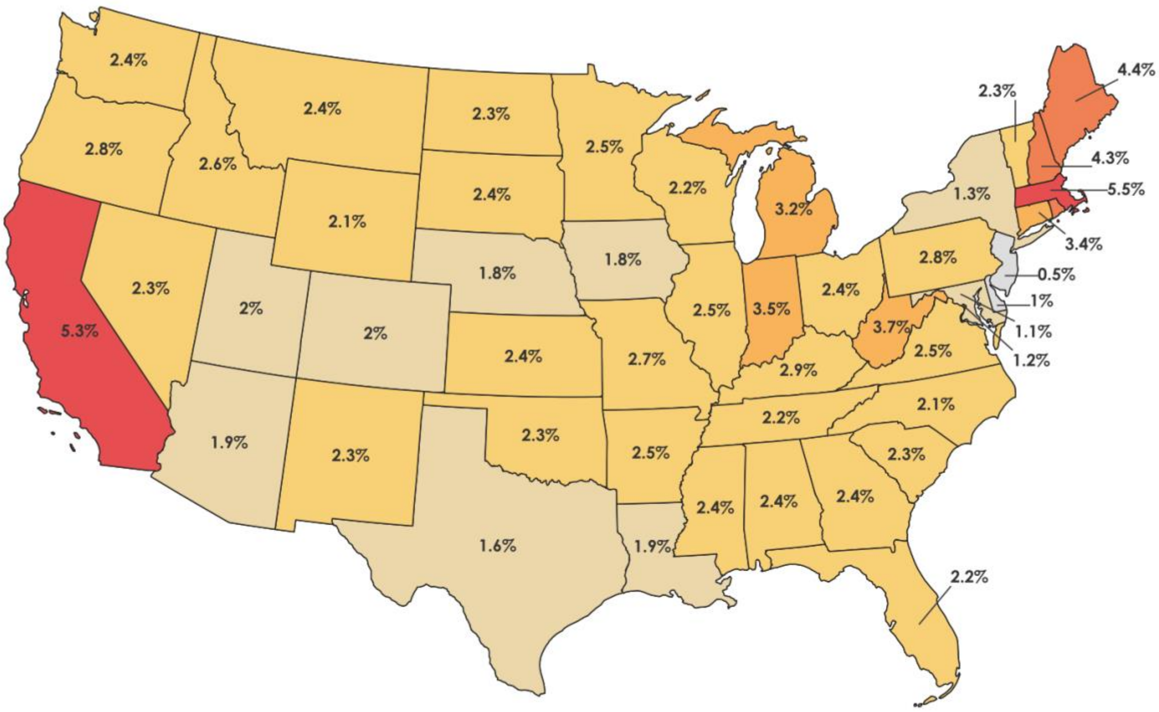
Figure 2. Inflation rate vs. rate of change in residential electricity prices



Source: Federal Reserve, EIA

Finally, national trends obscure very real differences among states. Between 2021 and 2023, 15 states saw residential rates increase faster than inflation, with rates in Massachusetts and California increasing more than twice the rate of inflation over that period. The states that have experienced the fastest rates of electricity cost growth can generally be grouped into three categories: 1) states in New England, 2) select Appalachian and Midwest states, and 3) California. Each of these regions has distinct factors influencing electricity rates, some of which are discussed further below.

Figure 3. Residential rate increase by state: 2010-2023 compound annual growth rate



Source: EIA

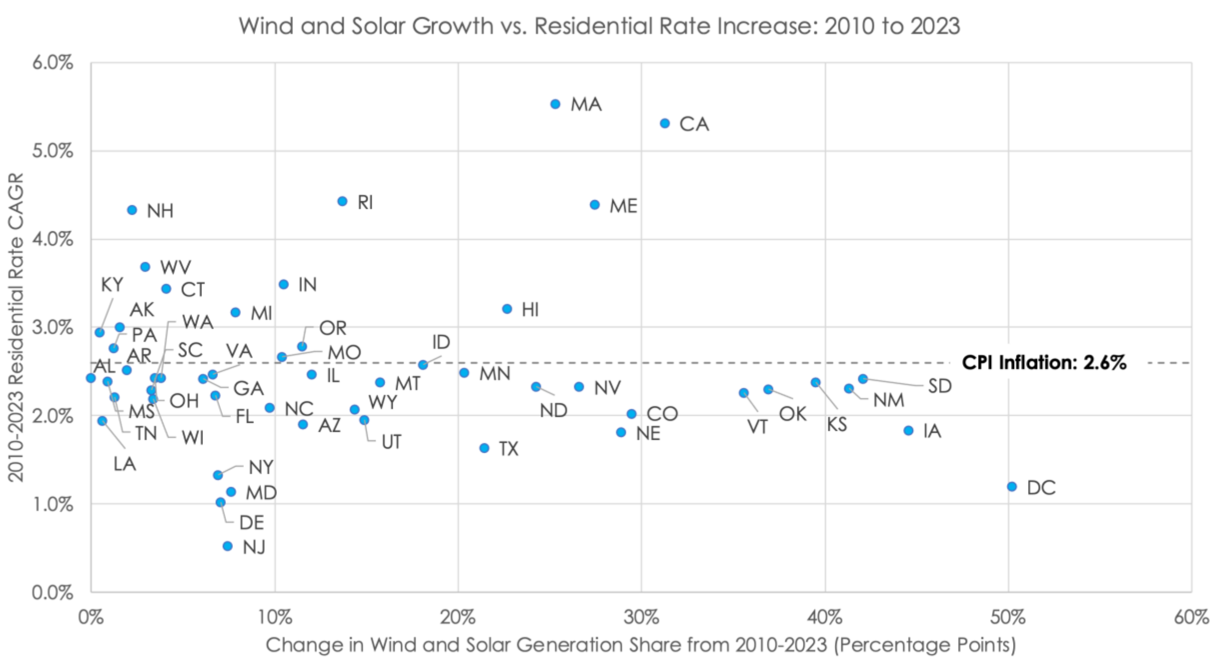
STATES WITH SIGNIFICANT CLEAN ENERGY GROWTH HAVE NOT GENERALLY EXPERIENCED RETAIL RATE INCREASES ABOVE INFLATION

While some have suggested that the growth of clean energy is responsible for rising electricity rates, the evidence does not support that assertion. Many of the states that have experienced the largest increases in wind and solar generation in recent years have not seen retail electricity rates increase faster than average. Several of the states with the most clean energy growth since 2010—including Iowa, New Mexico, Kansas, and Oklahoma—have seen residential electricity costs rise slower than inflation.

In fact, growing renewable energy deployment has been shown to drive electricity cost savings. Researchers estimate that the build-out of wind and solar in the Electric Reliability Council of Texas electricity market reduced wholesale electricity costs by $31.5 billion between 2010 and 2022, and by $11 billion in 2022 alone.[8] These savings are driven by wind and solar outcompeting more costly fossil fuel resources. Wholesale electricity costs are just a portion of the overall utility bill for electricity consumers in Texas, as bills also include the cost of delivering that electricity to customers through transmission and distribution infrastructure. Still, these savings are a factor in the relatively slower pace of electricity rate increases in Texas.

In addition, state clean energy policies have been shown to have modest cost impacts. Research from Lawrence Berkeley National Laboratory finds the average compliance costs for renewable energy standard policies to be approximately 3.5 percent of the average retail electricity bill, with significant variation across states depending on renewable energy credit market conditions, resource carve-outs, and other factors.[9]

Figure 4. Relationship between wind and solar growth and residential rate increases



Source: EIA 861M, EIA API, Federal Reserve

Figure 4 shows the relationship between increases in the share of electricity coming from wind and solar (the primary sources of clean energy growth in the U.S.) and the rate of increase in residential electricity rates since 2010. Many of the states that saw the largest increase in wind and solar over this period also saw electricity rates increase slower than overall inflation. For example, the share of electricity generated from wind in Iowa increased from 15 percent in 2010 to nearly 60 percent of the state's electricity generation in 2023 while the state's electricity rates grew at a rate slower than that of 42 other states.

Rates increased fastest in several New England states, California, West Virginia, and Indiana. While many factors have influenced rising rates in these states, several key factors are discussed below.

HOW ELECTRICITY RATES ARE SET

Regulated electricity rates are set through rate cases, where utilities put forward the costs they seek to recover from customers through rates. This process can be broken down into several parts:

- A utility will put forward a "revenue requirement," the total amount of revenue it seeks to recover from customers in electricity rates. This includes the utility's expenses, like fuel, operations and maintenance, and general administrative expenses, plus recovery of the utility's capital investments and a regulated return on investment. Regulators determine whether these expenses and capital investments are reasonable and have been prudently incurred, and approve recovery through rates.
- This revenue requirement is divided across customer classes (e.g., residential, commercial, industrial customers), ideally allocating costs to the customer classes that are causing those costs.
- Rates are further broken out into volumetric (per kWh), demand (per maximum kW), and minimum or fixed charges. There are many rate design variations and choices to align customer incentives with utility costs; incentivize consumer efficiency, flexibility, or electrification investments; ensure rate burdens are equitably allocated; and allot risks between the utility and customers. Charges may stay the same, or can vary across hours of the day, across seasons, or with scale of energy consumption.

There are variations on this model throughout the country:

- Municipal and cooperative utilities generally determine rates in a similar manner, with some differences. Rather than being overseen by a regulator, these entities are often self-governing, with rates approved by their board.
- Some states allow competitive retail electricity suppliers that can offer rates that are not set through the regulatory process described above, while transmission and distribution "delivery" rates typically remain regulated. Competitive "supply" rates often reflect electricity prices in wholesale electricity markets, and many states with competitive retail electricity supply still have a regulated "default" supply rate applicable to most customers.

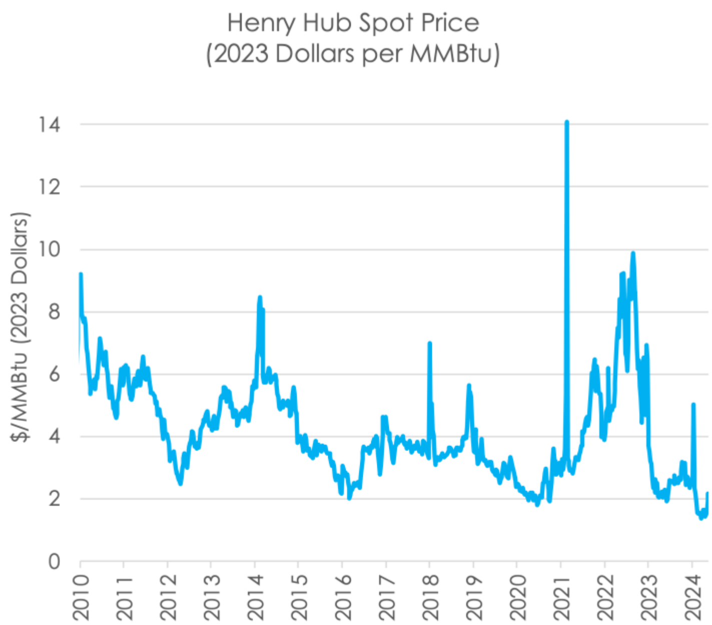
KEY DRIVERS OF RISING RATES: FOSSIL FUEL COSTS, WILDFIRE COSTS, AND RISING TRANSMISSION AND DISTRIBUTION COSTS

Numerous factors influence retail electricity rates. For many electricity customers, rates are set through regulated proceedings—"rate cases"—where utilities break down the costs they seek to recover through rates. These costs include expenses incurred in operating and maintaining their electricity system; the costs of fuel and purchased power; recovery of capital investments made in transmission, distribution, and generation assets and a regulated return on investment; and countless other types of costs. The complexity of utility ratemaking makes unpacking the drivers of cost increases equally complex. However, there are several trends underlying recent rate increases. As discussed in more detail below, the volatility of natural gas prices, rising costs for aging coal-fired power plants, the impact of wildfire mitigation and wildfire liability costs (particularly in California), and industry-wide acceleration of transmission and distribution costs are notable drivers of these increases.

NATURAL GAS PRICE VOLATILITY

Natural gas is a notoriously volatile commodity in the U.S., with price swings driven by boom-and-bust supply dynamics, extreme weather and, increasingly, global geopolitical uncertainty and exposure to global energy markets. Because of advances in drilling techniques, gas prices remained historically low for much of the 2010s, coinciding with significant increases in gas-fired electricity generation. However, this dynamic changed substantially in 2021, as Russia's invasion of Ukraine left Europe scrambling to reduce dependence on Russian gas, driving gas prices in the U.S. up by a factor of four in a matter of months as export markets responded to international demand. Elevated gas prices persisted throughout 2022. Surging fossil fuel prices drove inflation throughout the economy, and the electricity sector is no exception.

Figure 5. Natural gas price volatility



Source: EIA

Natural gas prices flow directly through to the prices consumers pay for electricity in several ways. Regulated utilities typically recover the costs of fuel directly through electricity rates, often with "riders" that allow for adjustments in rates as fuel costs vary from month to month.[10] However, as described below, high fuel costs experienced during periods of significant volatility are sometimes recovered over much longer periods, with customers paying for high fuel costs and associated financing costs for many years after an event. Gas prices also directly affect the price of natural gas-fired power in wholesale electricity markets,[i] the cost of which impacts customer bills.[11]

It's no surprise, then, that the states most reliant on natural gas for electricity generation were among those with the highest rate of retail price increases as gas prices surged since 2020, as shown below. This includes many states in New England, such as Massachusetts and Connecticut, as well as Florida, Pennsylvania, and Ohio. It is worth noting that many of these states are part of multi-state regional electricity markets like ISO New England or PJM; in these markets, customers in one state can be affected by significant reliance on gas in neighboring states.

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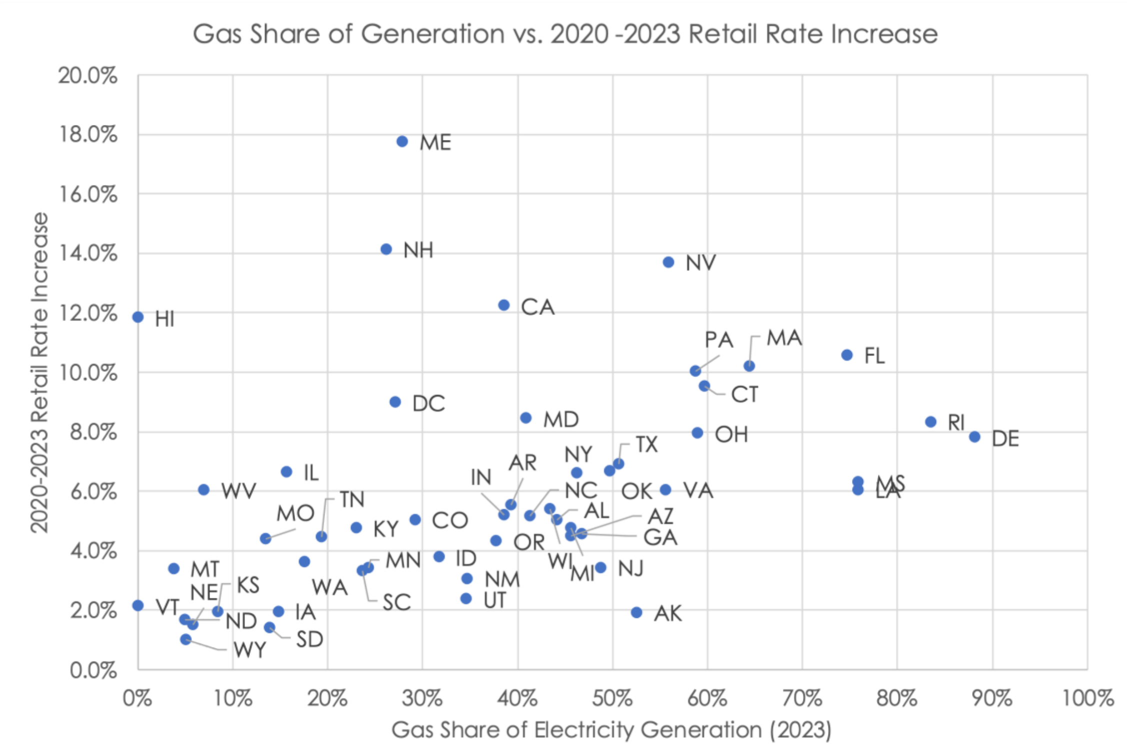
[i] In regions with restructured electricity markets, natural gas is often the "marginal" fuel for electricity generators—that is, the power plant that would need to be dispatched to meet the next increment of electricity demand and that sets the price of electricity often burns gas as its fuel. As a result, wholesale electricity market prices often reflect changing prices of natural gas.

Even in states in the middle of this pack, natural gas costs play a significant role; in North Carolina, an independent analysis of Duke Energy's electricity rates found that natural gas price volatility accounted for 46 to 67 percent of total residential electricity bill increases since 2017.[12]

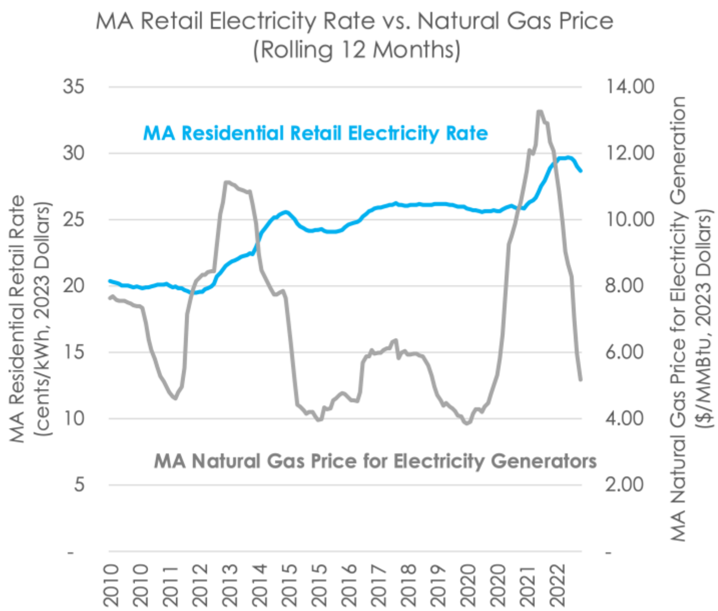
Figure 6. Relationship between reliance on gas generation and recent price increases



Source: EIA

Massachusetts has experienced a particularly large increase in electricity rates, which have been nearly double the rate of inflation since 2010. In 2023, 64 percent of the state's electricity was generated from natural gas, while the state sits within the ISO New England regional electricity market, where 49 percent of electricity demand in 2023 was met by natural gas.[13] Moreover, New England's gas supply faces significant constraints, especially at times of peak demand. As shown in Figure 7 below, significant gas price volatility in the 2012-2014 and 2021-2022 periods directly coincided with major increases in retail electricity prices, although it can take a year or more for the full impact of these price increases to be reflected in retail electricity rates, and the impact can persist well after prices have stabilized.

Figure 7. Gas and electricity prices in Massachusetts



Source: EIA, FRED

Elsewhere, volatile natural gas prices have had long-term consequences for electricity customers. In February 2021 during Winter Storm Uri, Oklahoma saw natural gas prices jump to over $300 per MMBtu, more than 100 times higher than typical price levels. Freezing cold temperatures froze gas supply and transportation equipment, just as demand for gas in homes and power plants surged to keep buildings warm. Regulators and courts have approved recovery of $4.5 billion in fuel costs incurred during Winter Storm Uri from gas and electricity customers over a period of 25 years. Public Service Company of Oklahoma estimates that a typical residential customer will pay an additional $4 per month for the next 25 years to cover these costs.[14] And in California, spiking natural gas prices from late 2022 into 2023 have added to the state's rapidly rising rates.[15]

TRANSMISSION AND DISTRIBUTION COSTS

Grid infrastructure across the U.S. is aging, and transmission and distribution lines built more than 50 years ago need to be replaced and modernized. So it's no surprise that utility spending on transmission and distribution infrastructure has increased substantially in recent years. According to data from Edison Electric Institute (EEI), capital investment in transmission and distribution infrastructure by investor-owned utilities increased 64 percent from 2016 to 2023, from approximately $53 billion to an estimated $87 billion.[16] This rate of growth in capital investment is more than double the rate of inflation over the same period.

This trend builds on decades of continued increases in transmission and distribution infrastructure costs. Data from Federal Energy Regulatory Commission (FERC) Form 1 shows that the combined, inflation-adjusted cost of transmission and distribution expenses, plus depreciation and an estimate of return on capital invested, rose from $30 per MWh of sales in 2010 (in 2023 dollars) to $44 per MWh of sales in 2022 (also in 2023 dollars). In that time, transmission and distribution costs rose from one-fifth of total electricity revenue requirements to one-third. Data from EEI projects that the trend of increasing capital investment in transmission and distribution infrastructure is likely to continue.[17]

IS ROOFTOP SOLAR INCREASING RATES?

Rooftop solar is growing rapidly as costs fall and consumers increasingly look to alternatives to manage rising electricity costs. Rooftop solar accounts for an estimated 16 percent of retail electricity demand in Hawaii, 12 percent in California, and more than 5 percent in Rhode Island, Massachusetts, Maine, and Arizona, per U.S. Energy Information Administration data.

Rooftop solar makes financial sense to customers in part because of “net metering” policies that allow customers to sell excess energy back to utilities at the retail cost of electricity. This energy can help avoid some utility costs—for instance, the cost of buying clean electricity from other power plants, losses from transmitting that power over long distances, and the cost of upgrading transmission and distribution systems. However, retail electricity rates for this exported energy can be higher than the costs a utility may avoid, and the utility may shift those costs onto other customers via changes to electricity rates.

There is substantial uncertainty about the magnitude of this cost shift due to complexity in rate design and varying estimates of the avoided cost of electricity, losses, and infrastructure. In California, one study estimates the cost shifted from residential rooftop solar customers to non-rooftop-solar customers at $4 billion, roughly 10 percent of total utility revenue requirements.[18] Rising utility costs, driven by wildfire-related costs described below, further contribute to the scale of this cost shift.

Rooftop solar, distributed energy storage, and other distributed resources can have significant value for the electricity system. Recent modeling that reflects the potential of distributed solar and storage to avoid transmission and distribution costs finds potential cost savings of $300-470 billion through 2050 from unlocking distributed resources at scale.[19] Other analysis estimates that virtual power plants—aggregations of customer-sited solar, storage, and flexible uses of electricity—have the potential to save $15-35 billion in costs from avoided centralized capacity over 10 years.[20]

Electricity rate design is an important lever to address potential cost shifting from rooftop solar, as well as enabling the potential of distributed resources on the grid. Better alignment of utility rate designs with long-run costs and constraints of the utility system can send more accurate price signals to consumers, incentivizing customers (or aggregators of customer-sited resources) to produce their own power or reduce consumption when generation, transmission, or distribution is most constrained.

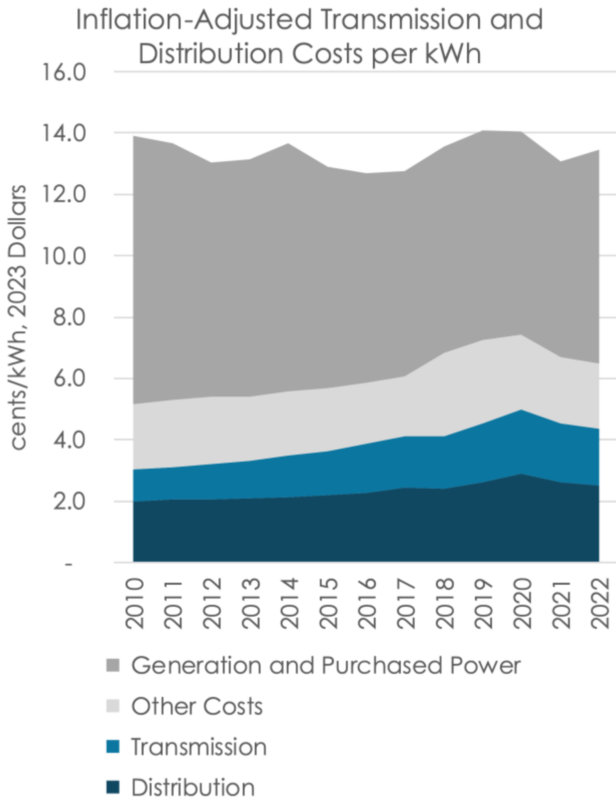
The composition of utility transmission and distribution costs is relatively opaque, but recent survey data highlights what is represented in these costs. According to EEI survey data from 2022, 34 percent of transmission capital expenditures and 37 percent of distribution capital expenditures could be classified as investments related to "adaptation, hardening, and resilience."[21] This includes repositioning, reinforcing, or undergrounding transmission and distribution equipment; installing equipment for vegetation management; and installing advanced sensing, monitoring, and metering systems to increase the resilience of transmission and distribution infrastructure. Expansion and replacement of transmission and distribution infrastructure makes up the bulk of the remainder. With customer-level outages increasing in frequency and duration,[22] further study is needed to determine the reliability benefit from these grid-hardening and resilience investments.

While some have suggested that the trend of increasing transmission and distribution investment is related to the build-out of clean energy, capital invested in transmission has been rising across the board, including in utilities that serve states with lower growth in clean energy, such as Florida Power and Light, Georgia Power, Ameren Missouri, and Duke Energy Ohio.[23]

Although transmission capital investment and costs to consumers have increased, that investment has not significantly expanded the transmission system's reach. Fewer miles of new high-voltage transmission have been added to the grid in recent years,[24] and where new transmission is being built, it often consists of smaller, local transmission lines,[25] rather than regional high-voltage transmission lines that could reduce wholesale electricity costs, tap into low-cost renewable energy resources, or connect regions of the grid to provide substantial reliability benefits. There are significant opportunities to expand grid capacity while mitigating cost increases through upgrading existing transmission lines with advanced conductors and grid-enhancing technologies. Recent research found that reconductoring could quadruple the amount of transmission capacity added by 2035, while saving customers more than $85 billion over the same period.[26]

Surging utility investment in transmission and distribution infrastructure is not necessarily realizing its full potential. Moving forward, it will be increasingly important for policymakers and regulators to guide this investment toward applications with broad benefits for customers, unlocking lower-cost sources of electricity supply and taking advantage of lower-cost, high-value opportunities like reconductoring, while ensuring that benefits flow to customers through rates.

Figure 8. Transmission and distribution costs for regulated utilities



Source: Estimated costs include depreciation, operating expense, and return on capital. Based on data from FERC Form 1 (via the Public Utility Data Liberation Project), return on capital estimated using 7 percent weighted average cost of capital. FERC Form 1 does not include municipal utilities or most rural cooperatives.

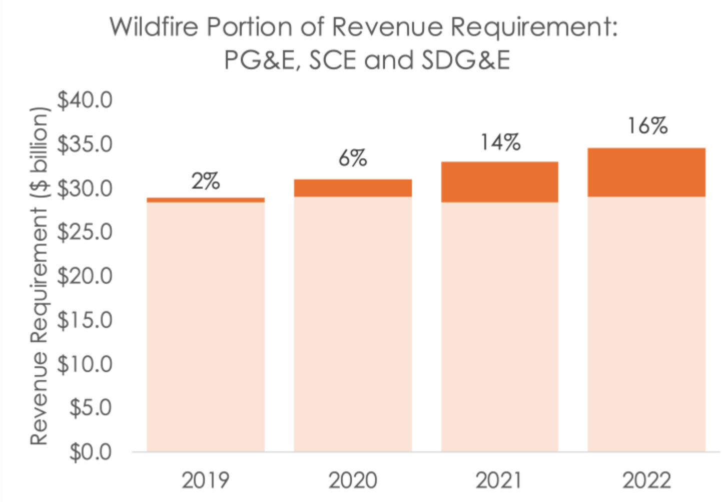
WILDFIRE RELATED COSTS

The Western U.S. has experienced its most destructive and damaging wildfire seasons in the past seven years, with annual costs from wildfire damages exceeding $10 billion in 2017, 2018, 2020 and 2021.[27] While the direct causes of wildfire ignition vary, climate change has been a significant contributor to the conditions that have made recent fire seasons more extreme.

In California, the impact of wildfires on the state's utilities' finances and consumer rates has been particularly acute. In 2018, the Camp Fire swept through Paradise, California, killing 85 people and causing over $16 billion in insured losses.[28] This deadly disaster was started by a faulty electricity transmission line that failed in high wind, and California law puts the liability for such events squarely on the utility that owns and maintains that transmission line, Pacific Gas and Electric.[29]

Since 2018, wildfire risk has been front and center in California electric utility regulation. Unable to absorb the full scale of liabilities from igniting the Camp Fire in 2018, PG&E declared bankruptcy in 2019. California's utilities and State Government then developed wildfire risk insurance pools, where utilities were responsible for funding their share. And to mitigate the growing risk of igniting wildfires, the state's utilities dramatically increased spending on wildfire prevention, distribution and transmission resilience, and other wildfire-related costs. According to the California Public Utilities Commission, wildfire-related costs that are recovered from electricity customers have grown to $5.5 billion per year, representing 16 percent of California's electricity revenue requirement for investor-owned utilities (the total amount of money to be recovered through rates), and nearly all the growth. Data from 2023 through early 2024 shows substantial additional growth of wildfire-related expenses, with costs accounting from 10 to 24 percent of utility revenue requirements for California's three large investor-owned utilities.[30]

Figure 9 – Wildfire portion of Revenue Requirement for California Investor-Owned Utilities

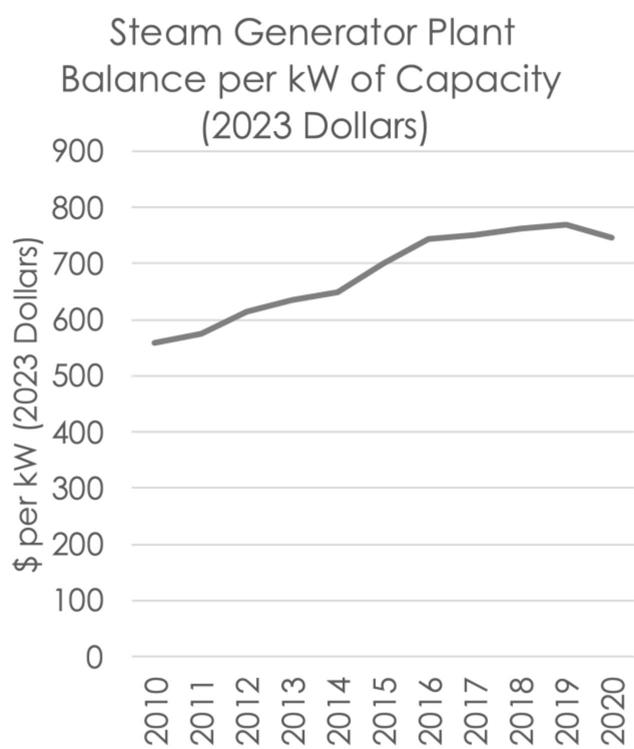


Source: CPUC

HIGH-COST COAL PLANTS

While electricity rates have largely tracked the cost of inflation, the cost of coal-fired power has increased with the age of the fleet. Despite the presence of economic alternatives, utilities have continued investing significant amounts of money in these aging, uneconomic coal plants—sometimes with the explicit encouragement of regulators or legislators. Typically, aging utility assets are depreciated over their lifetimes, leaving less capital to be recovered from customers as assets age. However, as coal plants have aged, the average amount invested in those plants has increased, as utilities make investments to extend the life of, maintain, and control pollution from these aging assets. According to data from RMI, the average remaining plant balance per unit of capacity for steam boiler plants (the FERC category that primarily consists of coal plants) increased from $560 per kW of capacity in 2010 to $745 per kW in 2020, in 2023 inflation-adjusted dollars.[31] These sunk costs (and a rate of return on this invested capital) are incorporated into the rates that retail electricity customers pay.

Figure 10. Rising capital invested in aging steam coal plants



Source: FERC Form 1 Data, via RMI Utility Transition Hub

Some utility-owned coal plants also ignore economic signals and drive-up costs for consumers by operating despite the availability of cheaper electricity from other sources. Analysis from RMI finds that coal plants operating uneconomically have cost consumers more than $17 billion since 2015.[32] In West Virginia, a state with notably rising residential rates, utility regulators have ordered the state's coal-fired power plants to operate at a capacity factor of at least 69 percent, despite declining economics of coal relative to other market options. Even as utilities have recommended retirement of aging coal assets to reduce ratepayer costs, West Virginia's Public Service Commission has pushed utilities to make significant investments to continue operating these plants at the expense of customers.[ii, 33] Despite the unfavorable economics of many coal plants, plans call for more than 120 GW of coal-fired power to continue operating past 2030.

Utilities have cheaper options, and thanks to incentives in the Inflation Reduction Act, the best time to start transitioning away from uneconomic coal is now. Energy Innovation analysis has found that new wind and solar can provide energy at a lower cost than the cost of operating 99 percent of coal plants in operation today, while the savings from replacing remaining coal plants with clean energy would be enough to finance more than 150 GW of storage capacity.[34]

UTILITY PROFITS AND INCENTIVES

Despite spiking gas costs, rising interest rates, and other factors, 2023 was the most profitable year in the last decade for U.S. investor-owned utilities.[35] Most U.S. utilities have a regulated business model that enables them to earn a regulated rate of return on invested capital, while recovering operational expenses from customers without an additional margin. This model has two important implications for electricity affordability. First, it makes the regulated rate of return that utilities can earn a critical parameter in determining the rates customers pay. And second, it incentivizes utilities to increase capital spending, even when other options may be more cost-effective for customers.

As part of a rate case, utilities typically propose a rate of return for regulators' consideration, and regulators generally approve rates of return that are close to, if not matching, utilities' initial requests. Approved regulated rates of return have remained consistent over time, even as financing costs and interest rates have fallen in other parts of the economy. Over the long run, the gap between the approved return on equity for investor-owned utilities and risk-free interest rates has risen substantially, with falling interest rates and stubbornly high regulated return on equity.[36] High rates of return get applied to the utility's invested capital and translate into higher rates for consumers.[37]

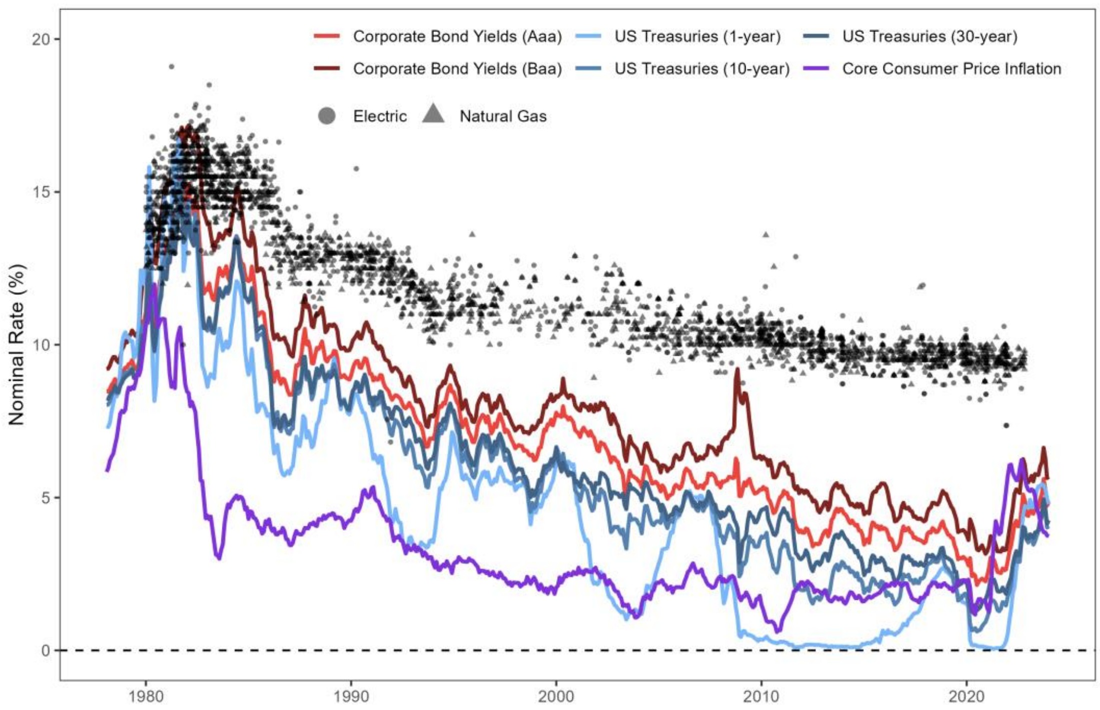
In addition, this regulatory model incentivizes utilities to increase capital investment. Selecting projects that involve significant capital investment can be more profitable for a utility than those that involve less capital spending or substitute capital spending for operational costs. For example, upgrading a transmission or distribution substation with top-of-the-line equipment can be far more profitable than a smaller investment in energy efficiency, or a contract with a portfolio of distributed energy resources that

[ii] For example: "AEP, American Electric Power, showed in their own testimony that ratepayers would be better off by $27 million per year if we don't make these investments and close down the Mitchell Plant in 2028. The Commission said, "We don't believe your numbers. We want you to make the investment in that plant and the Mountaineer plant and the Amos plant. We want you to make all necessary investments to keep those plants running through 2040." You've got a message from the Public Service Commission saying, "We don't really care about economics. We want the coal plants to continue running, and we want them running at their historical capacity factors, regardless of whether there's cheaper power available in the markets.""

could help avoid that large investment. A high return on equity compounds this issue; recent research found that a one percentage point rise in return on equity increases a utility's capital investment by 2 to 4 percent, all else held equal.[38]

High regulated utility returns and a business model that links utility returns to capital investment act as a multiplier to many other factors that are putting pressure on electricity costs. By incentivizing utilities to favor capital investments, these factors may contribute to rapidly rising transmission and distribution costs and high levels of capital investment in aging coal plants, while simultaneously making this capital investment more expensive for customers.

Figure 11. Return on equity and financial indicators



Source: Werner and Jarvis, "Rate of Return Regulation Revisited," 2024.

A CLEAN, AFFORDABLE ELECTRICITY SYSTEM IS CRITICAL FOR THE ENERGY TRANSITION

A transition to a clean energy economy requires electricity to remain affordable. Utility costs make up a significant share of income—often 8 percent or more—for low-income households,[39] and increasing electricity costs fall disproportionately on those who already bear an outsized burden. In addition, electricity costs that rise faster than the cost of natural gas and transportation fuels can make electrification of vehicles and home heating less financially attractive.

Luckily, clean energy technologies are expected to continue to decline in costs, enabling substantial emissions reductions in the electricity sector without increasing costs. After more than a decade of cost declines,[40] analysts expect significant further declines in the cost of solar, wind, and energy storage. The National Renewable Energy Laboratory's analysis of technology cost projections estimates that between 2024 and 2030, costs of solar will fall by another 20-30 percent, wind by 14-20 percent, and energy storage by roughly 25 percent.[41] Multiple studies have found that these declines in clean energy costs can enable the grid to reach high levels of carbon-free electricity without raising rates.[42]

However, the cost pressures described in this report risk consuming the potential savings from continued clean energy deployment. Regulators and policymakers need to ensure that consumers are protected from unnecessary costs and risks. Strategies they can use include:

- **Better planning practices:** Transparent and comprehensive resource planning that integrates up-to-date, market-informed costs of new generation resources, considers cost savings from retiring or lower utilization of existing resources, and maximizes cost-effective energy efficiency and customer-sited resources can reduce costs for customers.[43]
- **Competitive procurement of resources to get the best deal:** Competitive requests for proposals can help identify the most cost-effective way to meet the needs of the grid and are a critical source of market-based information on technology costs and performance characteristics, a key input to effective planning.[44] Competitive procurement can reveal opportunities for flexible demand-side resources, or virtual power plants, to meet grid needs at lower cost and more quickly.
- **Get more out of the existing grid:** Grid-enhancing technologies and reconductoring of existing transmission lines can enable better utilization of existing transmission assets and add significant capacity to the transmission grid at lower cost.[45]
- **Regional cooperation:** Enhancing regional cooperation can reduce electricity system costs through lower-cost dispatch of power plants, better utilization of existing transmission, and sharing spare capacity across regional utilities.[46]
- **Refinance coal debt:** Refinancing capital invested in retiring coal plants at lower interest rates can reduce customer costs associated with those plants, and enable utilities to reinvest in new, lower-cost resources, especially via proven tools like securitization.[47]
- **Fuel cost-sharing mechanisms:** Sharing the cost and risk of volatile fuel prices, like natural gas, can align utility incentives to manage fuel costs on behalf of

their customers, and invest in resources that reduce exposure to those price risks.[48]

- **Improve utility business models:** Regulatory tools can address the utility bias toward capital investments, incentivize efficiency and cost savings for customers, and address misaligned incentives.[49]

While concern about rising electricity costs mounts, the notion that clean energy is driving up costs is misplaced. The volatility of fossil fuel prices, the cost of climate-driven wildfires, and surging spending on aging infrastructure all contribute to rising rates, while falling costs of clean energy can help to offset these factors. Regulators and policymakers have a range of tools they can deploy to mitigate pressure on rising rates, ensuring an affordable and accessible transition to clean electricity.

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