Charles River Associates

Retail rate trends in the US

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Authors

Matthew DeCourcey
Mayank Saraswat

Charles River Associates
200 Clarendon Street
Boston, Massachusetts 02116

Prepared for

Edison Electric Institute
701 Pennsylvania Avenue NW
Washington, DC 20004

Table of contents

Executive summary

This new analysis conducted by experts from Charles River Associates finds that some currently prevalent narratives about rising electric rates are incomplete and potentially misleading. A widely reported increase in average retail rates in the US has been interpreted as indicative of a broader, national trend. This is not the case. Rather, in a few states and regions, rates have increased rapidly, putting upward pressure on the national average. Retail electric rates have generally been stable in other regions.

Where rates have gone up, the increases were driven by specific, localized factors that increased utilities' operating costs, causing rates to rise. Those factors differed by location and are caused by changes in markets, policies, and other circumstances beyond utilities' control. In general, the utilities have managed controllable costs effectively.

The pace and magnitude of rate changes were uneven. Over the past ten years, the total change in electric rates was consistent with inflation; however, during that time, there were periods in which the rate of increase was much higher and much lower. There is no single trend that accurately describes how the rates have changed.

This analysis focuses primarily on residential electric rates, as these tend to be of greatest interest to policymakers. The authors' intent is to describe important trends in retail electric rates and affordability, identify the main drivers behind recent rate increases, and evaluate claims about the impact of data centers.

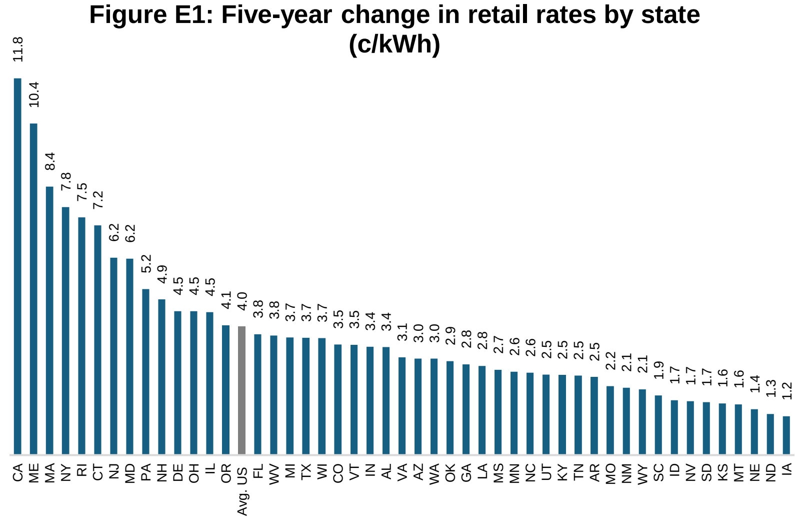
The study's primary findings are as follows:

- Prevailing narratives that there is a broad national trend of rapidly rising electricity rates are inaccurate or incomplete. Trends that use national averages can be misleading because those data obscure important differences among the different rates that comprise the average.
- Trends in the nationwide average are heavily influenced by large rate increases in specific areas.
  - In the Northeast (New England and New York), higher prices in wholesale electricity markets have caused rates to increase. Retail rates in the Northeast states are more susceptible to changes in wholesale electricity market prices because utilities there do not own generation.
  - In California, rates have increased within the last five years due to the cost of wildfires and wildfire mitigation. For some California customers, costs associated with the state's rooftop solar program may have raised bills significantly.

- Because the rate increases we observed in the Northeast and California were driven primarily by rising operating expenses that utilities recover at cost, the change in rates has not materially improved utility earnings.
- Data centers did not trigger increases in retail rates, with one exception. Where rate increases occurred, we have identified the primary drivers; moreover, the timing and location of the rate increases are not consistent with the timeline of data center development.
- Going forward, utilities and their state regulators have committed to protecting retail customers from rate increases caused by new data centers. The protections being embedded in new tariffs and ratemaking measures are designed to prevent subsidies from existing ratepayers, help maintain utilities' creditworthiness, and may put downward pressure on existing customers' retail rates.
- Recent capacity price increases in the PJM Interconnection, the thirteen-state regional power market that includes most of the mid-Atlantic US, are partly due to data centers and will put upward pressure on utility bills in some states. The specific circumstances that led to this outcome do not apply to other parts of the country.

All the data used in this study are publicly available. Retail rates are compiled and reported by the US Energy Information Administration (EIA). They include the average US rate, which is calculated by the EIA, and rates for individual states. The state-specific rates reported by the EIA were used to identify and quantify rate increases; Figure E1 indicates the five-year change in retail rates, expressed in cents per kilowatt-hour (c/kWh), by state for the period ending October 2025. Note that the largest changes in the rates over this time are in California and in the Northeast states.

Figure E1: Five-year change in retail rates by state (c/kWh)



The national average, which has been widely reported on, does not meaningfully describe how rates have changed in many places. For most, rates have changed less. Figure E1 shows that there are thirty-four states where rates changed less than the national average, and in some cases, by considerably less. There are also states where rates increased by much more.

The authors also utilized financial data reported by individual utilities to the Federal Energy Regulatory Commission. In the locations where there were large rate increases, we compiled annual Form 1 filings for each investor-owned utility. Because American investor-owned utilities are regulated on a cost of service basis, retail rates change when the utilities' costs of providing electric service change. Using the Form 1 data, we were able to confirm the correlation between the changes in costs for the utilities serving customers in California and the Northeast and the observed rate increases to then identify which categories of costs were drivers of the increase. In California, increases in operational spending related to wildfire mitigation and prevention accounted for a large portion of the utilities' cost increase. In the Northeast, the increasing cost of purchasing energy from the market was a key driver of utility cost increases.

These findings are relevant to a broad range of industry stakeholders including customers, investors, utility managers, and others. We expect that regulators and policymakers may find this report particularly useful. Understanding that rates and trends vary geographically highlights the need to seek interventions that will address the factors specific to a given region that may be causing rates to increase, while the identification of root causes will inform the selection and implementation of solutions in each locality.

1. Introduction

The objective of this study is to understand recent trends in retail electric rates, identify where retail rates have increased most, and explain what caused the increases.

Our analysis was conducted in two parts. First, we compiled and analyzed rate information published by the US Energy Information Administration (EIA), which includes monthly retail rates for each state as well as national averages calculated by the EIA. We determined that the trend in the national average retail rate is not a good benchmark for rate trends in most locations. Rather, rates and rate trends vary widely by geography.

We found that over the past five years, the average national rate has increased significantly, as has been widely reported. However, this does not indicate a broad national trend of increasing rates. Instead, we found that rapidly increasing rates in the Northeast (which we define as New York and the New England States for purposes of discussion herein) and in California accounted for most of the change in the average. In most of the rest of the country, increases in retail rates were moderate; in some cases, rates increased at a pace slower than general inflation.

While a majority of our research focused on understanding the largest rate increases that have occurred, our analysis supports the important finding that most American ratepayers have not been burdened with rapid increases in their electric costs and that efforts to control costs have generally been effective. Although circumstances differ from case to case, we expect that the effectiveness of utilities' efforts to control costs, constructive oversight by regulators, and contributions from a diverse range of industry stakeholders have likely contributed to this outcome.

In the second part of our study, we sought to identify the causes of the increases observed in the Northeast and California. American utilities are regulated on a Cost of Service (COS) basis, which means that a utility's retail rates are set at a level sufficient to allow it to recover the costs of serving customers, including the cost of providing a reasonable level of return to investors. Thus, understanding how a utility's costs have increased helps to answer the question of why its rates have also increased.

For this analysis, we relied on financial data filed by the utilities with the Federal Energy Regulatory Commission (FERC). Each year, electric utilities are required to file a Form 1 report, which includes, among other things, a full set of financial statements and details on their operations and operating expenses. CRA developed a database of utility costs on an account-by-account basis, with which we analyzed trends in costs and decomposed changes to identify drivers. We found that the increases in rates we observed correlated with increases in the utilities' costs that were consistent in each region. We also found that much of the change was clearly attributable to specific factors.

The key drivers of the cost increases were shared by the utilities within each region but differed between the regions. In the Northeast, we found that increases in the cost of purchased power were driving up utility expenses and, therefore, causing the rates to increase. In California, spending on wildfires was the primary driver of cost and rate increases. In both regions, there were other costs that also increased during this period, but our analysis shows that spending on purchased power and wildfires, respectively, were key drivers of increases in the utilities' costs.

In both the Northeast and in California, the large majority of the cost increases were operational expenses, not capital investments. Because operational expenses are recovered in rates on a pass-through basis (e.g. without an added return for investors), the observed rate increases have not meaningfully enhanced earnings for the utilities in those regions.

Moreover, we conclude that rate increases in these two regions were not the result of ineffective cost management. In the Northeast and in California, the factors that caused the cost of serving customers to increase could not have been reasonably anticipated and were largely outside of the utilities' control. In many instances, we found that efforts to contain other costs have been effective and have helped to mitigate total impacts to customers.

Finally, our analysis shows that, for the most part, retail rates have not been driven up by the emergence of data centers as large consumers of energy. Few hyperscale data centers have started operations, making it unlikely that they could have contributed to rate increases, and the markets where rates have increased are not those where most data centers are being built. In the future, we expect that emerging best practices in regulation and ratemaking will protect utility customers from rate increases caused by the connection of new data centers. We did find that the high prices observed in recent capacity auctions in the PJM Interconnection, the regional power market that includes thirteen states and the District of Columbia in the mid-Atlantic, were caused, in part, by expected demand growth from data centers. In some states within the PJM footprint, higher capacity prices will cause upward pressure on customer bills.

In the sections that follow, we describe our approach and results. Note that all references to rates are to retail residential rates, which we chose as our focus in expectation that those rates would be of greatest interest.

1.1 Summary of conclusions

Our primary conclusions are as follows:

- Prevailing narratives that there is a broad national trend of rapidly rising electricity rates are inaccurate or incomplete. Trends that use national averages can be misleading because those data obscure important differences among the different rates that comprise the average.

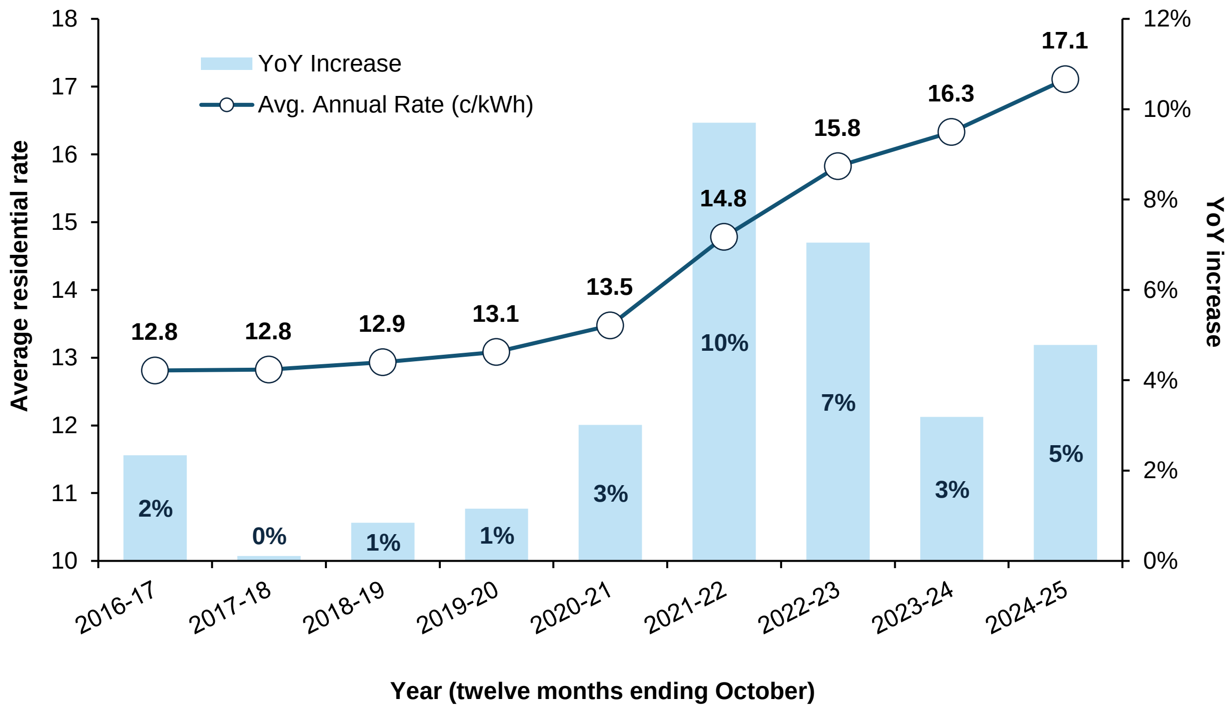
- In most of the country, rates have been stable, which indicates that efforts to contain utility costs have generally been effective.
- Trends in the nationwide average are heavily influenced by large rate increases in specific areas.
  - In the Northeast, higher prices in wholesale electricity markets have caused rates to increase. Retail rates in the Northeast states are more susceptible to changes in wholesale electricity market prices because utilities there do not own generation.
  - In California, rates have increased within the last five years due to the cost of wildfires and wildfire mitigation. For some California customers, costs associated with the state's rooftop solar program may have raised bills significantly.
- With one exception, data centers did not trigger significant increases in retail rates. Where rate increases occurred, we have identified the primary drivers; moreover, the timing and location of the observed rate increases are not consistent with the timeline of data center development.
- Going forward, utilities and their state regulators have committed to protecting retail customers from rate increases caused by new data centers and are approving new tariffs and ratemaking measures that embed those protections. These protections reduce risk, which ultimately lowers utilities' expenses including capital borrowing costs. In some cases, data centers may put downward pressure on retail rates.
- Recent capacity price increases in PJM increased in part due to data centers, which will put upward pressure on utility bills in some states. The specific circumstances that led to this outcome do not apply elsewhere.
- Where rates have increased, the primary cause has been increased operational spending caused by factors beyond the control of utility management. In these instances, the increases have not meaningfully enhanced utility earnings.

2. Rate trends: National averages, long-term trends, and the importance of geography

Context is crucial, particularly regarding timing and geography. Where there have been large increases in rates, local factors have been the cause.

EIA tracks retail prices for various types of energy including electricity across the country.[1] The data it reports include electric utility rates for each state as well as an average US utility rate, which EIA calculates[2]. Year-to-year changes in the average rate are shown in Figure 1.[3,4]

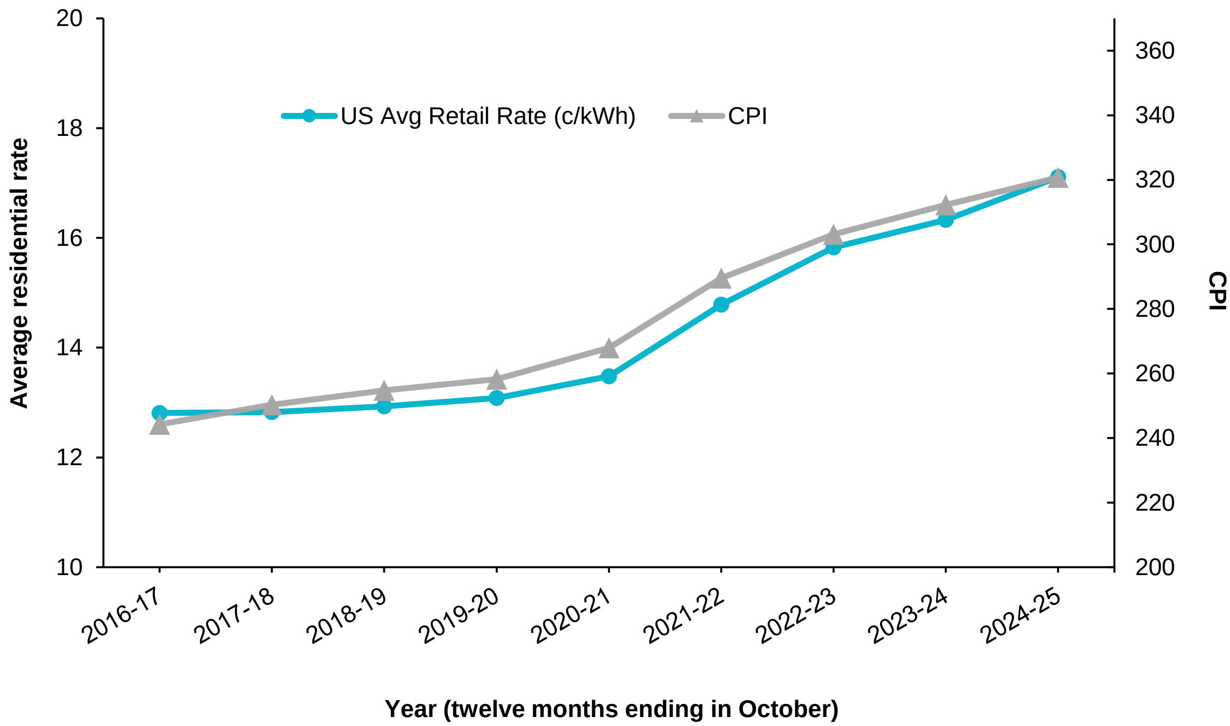
Figure 1: Change in average US retail rates



These data show a change in trajectory starting around 2021. Previously, rates had been very stable but then grew rapidly for consecutive years, starting with the 2021/22 period. Subsequent increases were smaller but increased rates that were already high. As we discuss later, conditions in California and the Northeast drove much of the change in the national average; additional factors that likely contributed include, among others, recovery from the COVID-19 pandemic and changes in global commodity prices.

The percentage change in average retail rates since 2016/17 roughly equaled the change in the Consumer Price Index (CPI) – which is to say that, on average, retail rates have largely tracked inflation. During the first five years, the retail rates changed very little. Then, with the two large year-over-year increases in the rates that began around 2021, the total change in the retail rates since 2016/17 caught up with the total change in CPI, and the trends remained closely correlated thereafter. Ultimately, the average retail rate and CPI each increased by about 30%. Figure 2 compares the same average retail rates shown in Figure 1 to the CPI.

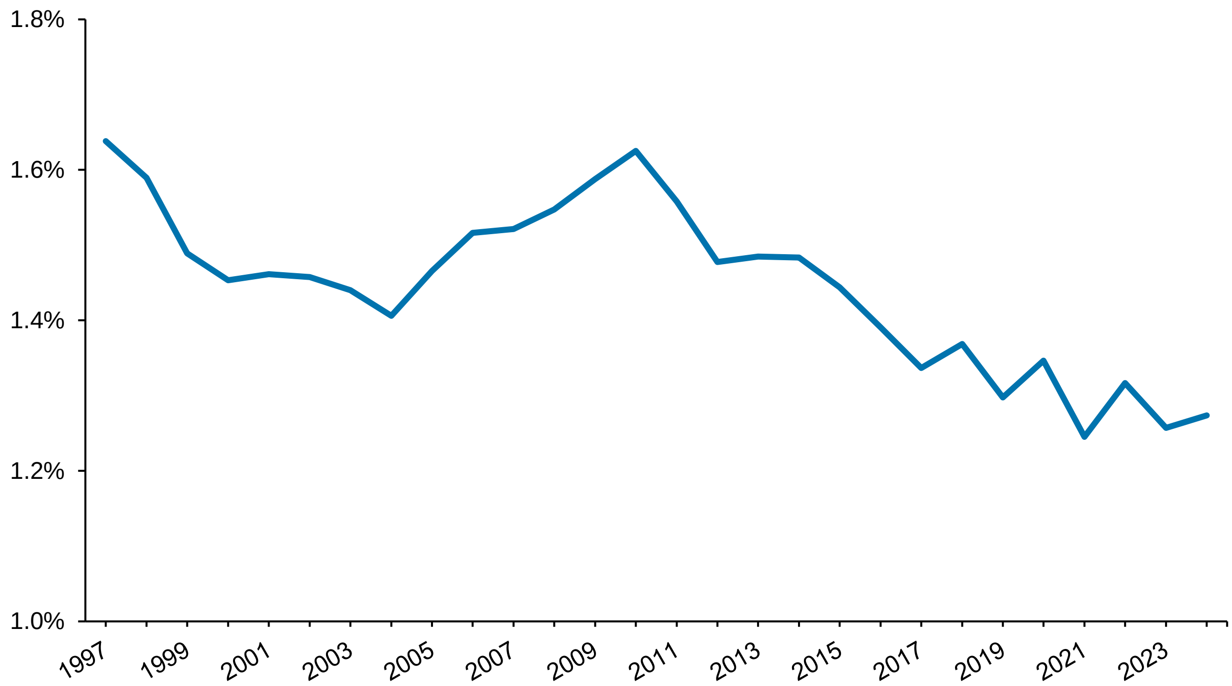
Figure 2: Average US retail rates vs. CPI



Notably, the CPI increases rapidly at around the same time that retail rates increase, suggesting that some of the same influences that caused CPI to increase, particularly impacts from COVID, also contributed to the rise in rates. In the sections that follow, we discuss changes in utility spending that caused the average rates to rise.

Another measure of affordability is the proportion of total household expenditures spent on electricity bills. Personal Consumption Expenditures data from the Bureau of Economic Analysis (Figure 3) show that the share of total household expenditures spent on electric bills has historically been low and has declined steadily.[5] In 2024, electricity bills made up 1.3% of household expenditures, on average.

Figure 3: Electricity as a share of average household expenditures

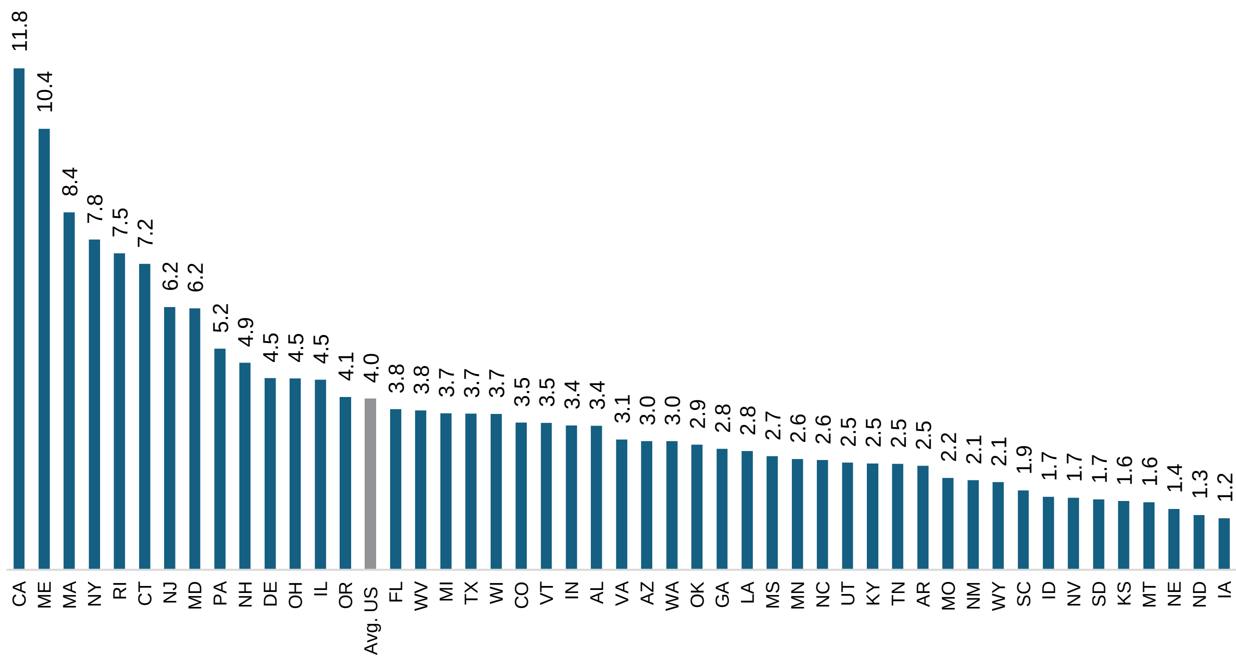


These data provide helpful context and add to the discussion about recent trends in retail electric rates. Nonetheless, customers who struggle to afford their utility bills can be impacted by a rate increase, regardless of how national rates and household expenditure data may have evolved over the previous five or ten years.

2.1 Disparate state trends

Retail electric rates vary widely between states and have followed different trends in the past ten years. Geography and differences in regulation and market structure, particularly the question of whether electric utilities own generation, account for much of the difference in how rates changed.

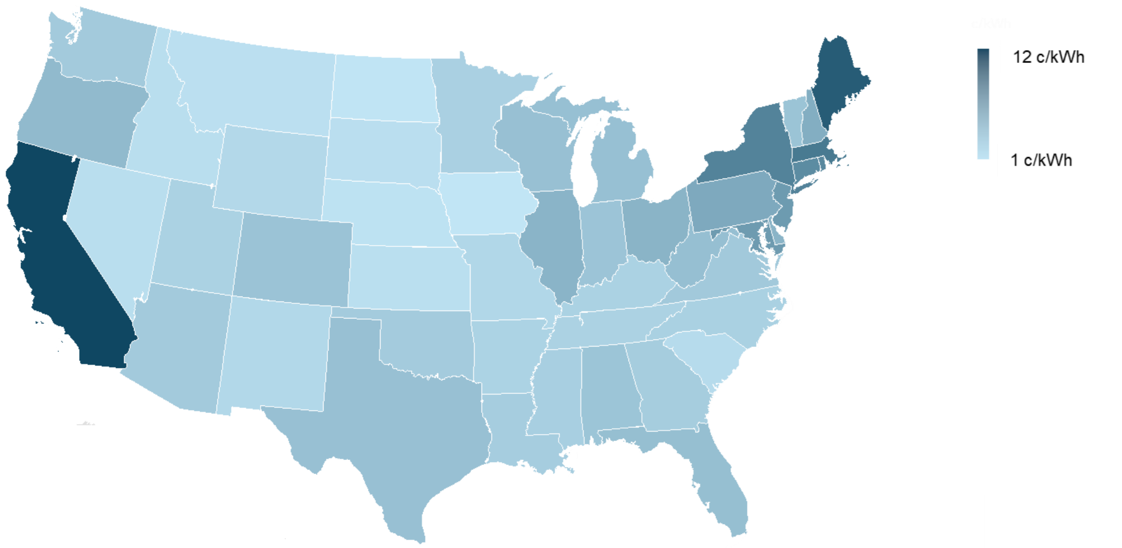
Figure 4: Five-year change in retail rates by state (c/kWh)



Over the last five years, the average US retail rate increased in the past five years by about 4 c/kWh, but the change in rates varied widely from state to state, as shown in Figure 4. As a result, the change in the US average rate is an inaccurate indicator of how rates have changed locally**.** In the majority of states (thirty-four out of forty-eight), rates increased by less than the change in the national average. In many instances among that group, the increase was much less.

Figure 5 visualizes these rate changes in a "heatmap," where the shading indicates the magnitude of the rate increase experienced in each state, which helps to highlight geographic trends.

Figure 5: Five-year change in retail rates by state



In particular, these data and subsequent analyses indicate that there are three prevalent trends in the retail rates:

1. ***First***, rate increases in most of the country were moderate; in many states retail rates increased either more slowly than inflation or at about the same rate.

2. ***Second***, rates in the Northeast increased more than the rates in other states. As we discuss below, wholesale electricity prices rose during this period, which increased utilities' costs and caused rates to rise.

3. ***Third***, rates in California rose much more than rates in other states. Wildfire-related spending in the past five years was the primary driver.

The following sections of our report describe analyses of utility financials that CRA undertook in order to identify the primary drivers of the rate increases and understand their impacts. In section 4.2, we discuss recent events in PJM, a wholesale electricity market in the Mid-Atlantic, that impacted retail rates in some states in 2024/25; these impacts are not fully captured in the five-year rate changes discussed above.

3. Financial analysis: Understanding why the rates went up where the rates went up

In areas where rates increased, factors specific to the locality made it more expensive to serve customers, causing retail rates to increase.

In the Northeast, rising prices for wholesale electricity caused rates to increase. In California, wildfires and wildfire mitigation spending caused rates to rise. Elsewhere, rate increases were moderate.

American utilities are regulated on a Cost of Service (COS) basis, and rates are set to allow a utility to recover the costs it incurs plus a return on the capital it deploys on behalf of its customers. Under COS regulation, retail rates increase when a utility's costs increase. Observed rate increases should thus be explainable from increases in utilities' costs.

To understand these increases in costs, CRA compiled data from annual financial reports that Investor-Owned Utilities (IOUs) in the US are required to file with FERC each year, known as the Form 1. The filings include, among other things, a complete set of financial statements for each IOU along with highly granular data for capital assets, financing costs and obligations, Operating Expenses (OpEx), and other financial information.

We analyzed these data to identify changes to the cost structure of each of the major IOUs operating in the regions where large rate increases were observed. Because the dataset we used is highly granular, we were able to narrow the focus of the analysis until we identified the specific categories where costs increased significantly and compared those changes to the changes we observed in the rates.

In several instances, we report utility-specific results to demonstrate these findings. Where that is the case, we have chosen not to identify the utility by name because of concerns that the inclusion or omission of some companies but not others could mislead or confuse the reader. For the same reason, we also express all financial results on a unitized c/kWh basis.[6] While not without its shortcomings, we believe this is a reasonable way to report utility financials. Normalizing costs in this manner has the additional benefit of allowing for direct comparisons between utilities of different sizes.

3.1 Northeast

The Form 1 data show a large increase in the cost of purchased power for the Northeast utilities. Other costs changed as well, but changes in purchased power costs were a key driver. IOUs in these states do not own generation. In most cases, they purchase electricity on behalf of their customers from the wholesale market or through bilateral contracts.[7] Costs of purchased electricity are passed through to customers in retail rates.[8] All else equal, when costs increase, rates increase as well.

Below, we compare changes in spending across all categories for two Northeast utilities. Figure 6 shows data for a utility whose total costs in 2019 were 18.5 c/kWh. By 2024, the latest year Form 1 data that were available, costs had increased to 22.6 c/kWh, putting upward pressure on rates. More than half of the total increase is due to the increase in the cost of purchased power.

Figure 6: Northeast IOU #1: Five-year change in spending

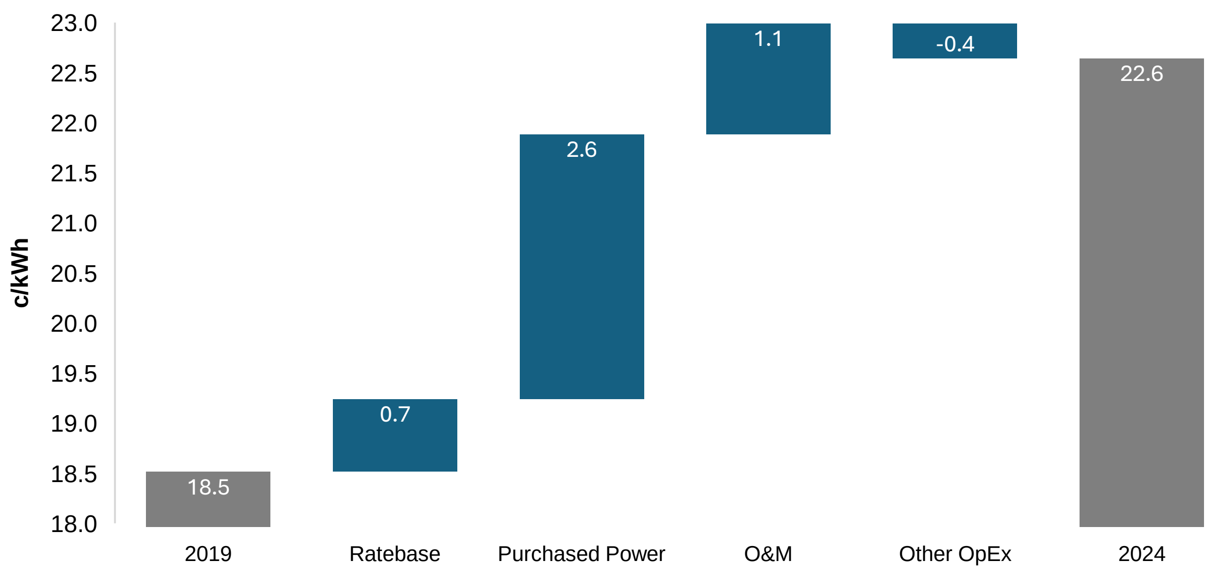


Figure 7: Northeast IOU #2: Five-year change in spending

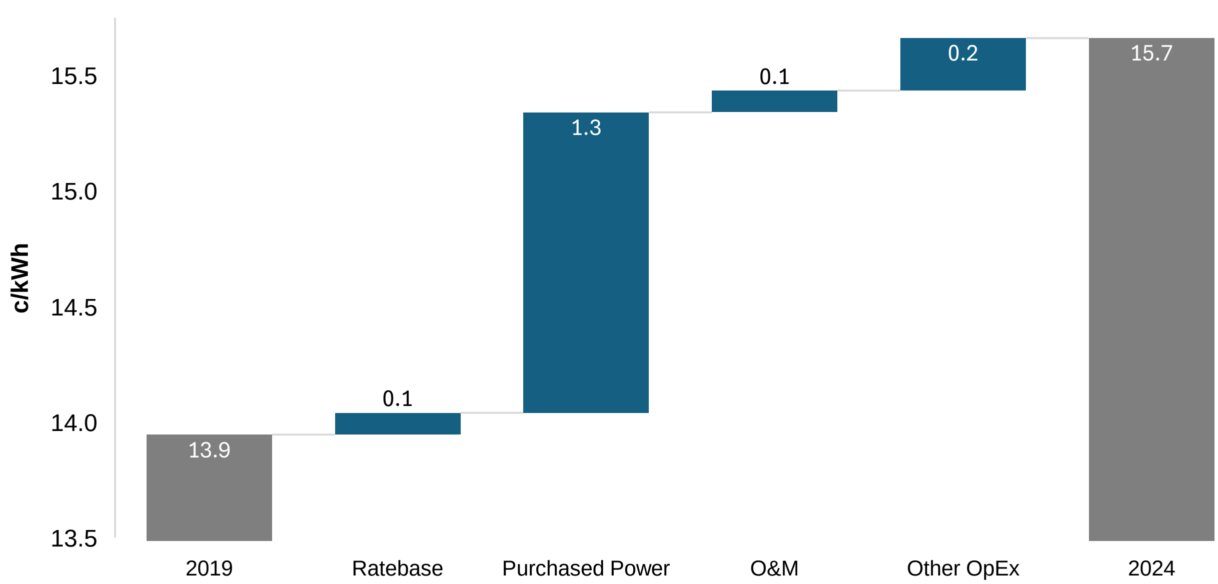


Figure 7 shows the increase in costs for a different IOU in the Northeast. Here, the increase in purchased power accounts for more than 70% of the total change in costs between 2019 and 2024. We observed similar trends in other IOUs in the region.

Market structure is an important factor for these large changes in costs. IOUs in the Northeast states (among others) do not own generation. Instead, they purchase electricity from the wholesale market to meet their customers' needs. Because the cost of the market purchases is passed through to customers on a dollar-for-dollar basis, customers are exposed to changes in wholesale rates more than customers of vertically integrated utilities, whose ownership of generation generally serves as a hedge against market volatility.

This is a particular concern in the Northeast states, where wholesale markets tend to be expensive and volatile, largely because of the region's location towards the end of the North American interstate natural gas pipeline network. When natural gas pipeline constraints arise, electric prices can rise quickly because much of the region's generation is gas-fired. During this period, wholesale prices rose significantly in both New York and New England. CRA confirmed that changes in wholesale prices were consistent with the reported changes in purchased power costs.[9]

Outlook: Considering new investments

Exposure to volatile prices and price increases in the wholesale market is an actionable problem. If they chose to do so, the Northeast states could make investments that would reduce that exposure and reduce electricity costs. Options include investments in generation capacity, natural gas infrastructure, bilateral contracts, grid modernization, and demand-side measures, all of which would require the fixed costs of new investments to be borne by customers in order to displace future volatility from wholesale markets.

In this regard, the Northeast finds itself in a familiar situation because it has long dealt with the challenges associated with volatility in energy markets driven by infrastructure and geographic factors. Although the cost of new infrastructure is also likely to be high, policymakers in the region have expressed interest in comparing costs and benefits to identify the right mix of investments that can balance cost and uncertainty.

3.2 California

Our approach to analyzing cost changes in California was generally the same as the one we used for the Northeast states. Year by year, we reviewed changes to utility spending to identify which types of spending were increasing the most and which categories of increase were the largest contributors to the total spending increase.

We found that increases in wildfire spending increased dramatically for all the California IOUs. Most of the wildfire costs are OpEx; specifically, most wildfire spending is recorded as distribution operating and maintenance (O&M) expense. The change in O&M accounted for most of the utilities' change in total spending over the past five years; moreover, the magnitude of the change in spending is consistent with the change in the retail rates.

Among the data sources that corroborate this finding is a recent study by the California Public Utilities Commission (CPUC), submitted to the state legislature in September 2025, which reports that the state's three largest IOUs spent more than $40 billion on wildfire-related costs in the five years between 2019 and 2024, of which approximately $26.5 billion was for wildfire mitigation programs and $13.5 billion was for wildfire insurance.[10]

This makes wildfire costs one of the California IOUs' biggest expenses. The sudden emergence of new, large, and difficult to control spending items increases the likelihood of significant rate increases.

For some California customers, costs associated with the state's Net Energy Metering (NEM) rooftop solar program may have raised bills significantly. The NEM program allows utility customers who build on-site generation to use the energy they produce to offset their billed consumption. Customers who own generation are paid at a fixed rate for the energy they produce. Rooftop solar generation is the technology most commonly installed by customers participating in the NEM program.[11]

California's NEM rules provide customers compensation for generation that exceeds their consumption. Customers on the NEM rate that produce more than they consume can sell the excess back to the grid at a set rate. According to the CPUC's September 2025 report, the rate paid to some NEM customers who sell back to the grid has at times been significantly greater than its value.[12] Under these circumstances, rates for customers not participating in NEM can increase. As the CPUC report explains, the NEM program participants are displacing all of their consumption and selling their excess energy at a set rate that is more than the energy is worth, resulting in a "cost shift" for the non-participating customers that can be significant. The CPUC estimates that in 2024, the cost shift for residential customers was nearly $6 billion.[13] Impacts on rates from the NEM program can vary as a result of changes in the program participants' generation, the wholesale price of electricity, and other factors.

Rate increases are driven by operating expenses

The finding that most wildfire spending is OpEx is important. Utilities recover OpEx on a pass-through basis, as opposed to investments in rate base, for which they are authorized to earn a return for their investors. At times, concerns over affordability can prompt responses that are aimed primarily at reducing utility earnings. Rate freezes, bill credits, caps on authorized returns, and similar measures are all predicated on the notion that a utility and its shareholders should absorb some of the burden of rising rates regardless of whether their decisions and actions contributed to them.

In California, policymakers should recognize that rate increases driven by the need for more OpEx do not enhance a utility's earnings and that unduly restrictive regulation for the sake of putting downward pressure on rates during a time of crisis could create adverse consequences in the long run.

Outlook: Wildfire reform and future challenges

Presently, there is no clear indication that operational wildfire spending is likely to significantly decrease in the future. Future rate base investments for wildfire mitigation, if required, could put additional upward pressure on rates.

Policymakers and regulators are considering a wide range of solutions. In 2025, new legislation was enacted to support infrastructure investments and grid reliability and commit $18 billion in contributions to the California Wildfire Fund, an entity administered by the state that provides critical liquidity to the state's three IOUs for wildfire expenses.[14]

Changes to the manner in which the utilities are regulated and rates are set are also being considered. In late 2025, the IOUs jointly submitted recommendations emphasizing shared responsibility and regulatory adjustments to stabilize costs and protect customers.[15]

Policymakers are also considering expanding the use of non-traditional financing tools like securitization. In other settings, securitization has been shown to benefit customers by providing access to low-cost capital, but implementation can be complicated, and care must be taken to avoid risks that include cost shifting, impacts to the IOUs financial integrity, and excessive debt burdens, among others.

4. Data centers: Focus on customer protections

Where rates have increased most, data centers were not the cause. Looking forward, new data center tariffs and agreements will insulate existing customers from the costs of serving data centers. However, customers of non-generation-owning utilities in PJM were recently exposed to wholesale capacity price increases driven in part by data centers.

As discussed above, the largest increases in retail rates observed in our analysis were in the Northeast and California. It is highly unlikely that data center development contributed to the rate increases in these regions because few major data centers are being built there.

4.1 Data center tariffs protect existing customers

In jurisdictions across the US, utilities and state regulators have developed and implemented new tariffs and agreements that protect existing customers from the costs and risks associated with serving new large load customers, such as data centers. These tariffs and agreements govern the provision of retail service to large load customers and most are in states that allow utilities to own and build generation. Although there is considerable diversity in their structure, specificity, and ratemaking mechanics, they share several common features to protect existing customers.

The common features we observed in large load tariffs and agreements across the US are summarized in Table 1 below. Fundamental to these tariffs and agreements is the requirement that new large loads fully or substantially fund the new generation, transmission, and other upgrades needed to serve them. The large loads are also required to pay for the studies to determine any upgrades. The tariffs and agreements generally ensure that utilities can recover their costs, including a rate of return, from the infrastructure they own and operate to serve new large loads. These retail provisions protect customers from paying the costs of building energy infrastructure to serve new large loads, ensuring that the incremental costs to serve large loads are borne by the large loads themselves, which prevents cost shifts to a utility’s existing customers.

Table 1: Customer protections in large load tariffs and agreements

Feature	Description	Customer protections
Funding for system upgrades	Investments needed because of a large load customer's entrance are funded by that customer	Prevents subsidy from existing customers
COS rates	Regulators require that utilities recover their entire COS, including returns, from large load customers	Prevents subsidy from existing customers
Contract minimums	Long-term contractual commitments	Prevents stranded costs
Billing minimums	Binding minimum billing requirements	Prevents stranded costs
Exit fees	Large fees for early exit	Protects against default risk
Credit requirements	Credit matrix sufficient to cover exposure for utility capital outlays	Protects against default risk

Minimum contract lengths are another common feature of large load tariffs and agreements, which require new large loads to enter long-term contracts with the utility, typically ten years or more, helping prevent stranded costs by ensuring that new large loads make long-term financial commitments to the utility and its service area. These new tariffs and agreements also require the large load to pay a minimum monthly amount (e.g., 85-100% of contracted demand), which ensures the large load will pay its cost of service during the contract term, even in the event the load does not materialize as quickly as expected. If the large load does not consume the energy specified in its contract, or terminates the contract early, the large load tariffs and agreements have features such as exit fees and other contract “off ramps” designed to protect the utility and its customers from having to pay for infrastructure built (in whole or in part) to serve the new large load.

Regulators also require the large loads to be creditworthy, sometimes requiring collateral, which, together with exit fees, protects the utility and its customers from the risk that the large load will default or otherwise terminate the long-term contract earlier than expected. Doing so also helps to reduce the uncertainty in utility load forecasts, which has created challenges in some regions.

With appropriate ratemaking protections like these in place, adding data centers to the grid can potentially benefit existing utility customers. Certain types of utility costs are shared by all the customers the utility serves. Adding new customers means that those costs are spread more widely, and, since data centers are large users, they may absorb a significant portion of the total shared cost, reducing the cost for existing customers.[16] The size of the benefit would depend on the specific details of the large load and the host utility.

Additionally, credit-related requirements like the ones described above that regulators are imposing on new data centers help support the financial integrity and creditworthiness of the host utility. This helps the utility access capital markets at competitive rates, which is an important part of keeping retail rates affordable.

4.2 PJM States

The customer protections included in new data center tariffs and agreements discussed above will insulate customers from rate increases resulting from new data centers. This has not always been the case in PJM, where a confluence of factors, including data centers, has led to recent increases in retail rates in some states. PJM's benchmark capacity price increased by 833% between the 2024/25 and 2025/26 capacity delivery years. Even after regulatory intervention that lowered price caps, PJM's capacity prices increased by an additional 22% for the 2026/27 delivery year, which will affect future rates.[17]

Utilities that do not own generation or have bilateral capacity contracts purchase capacity from the PJM capacity market at prevailing market prices. The costs of such capacity purchases are directly passed through to retail rates. As such, the largest retail rate impacts in PJM are felt by customers of the utilities most exposed to PJM's wholesale capacity market, such as in states that do not permit utilities to own generation. For example, retail customers in Pennsylvania and Maryland faced the highest rate increases in the US between 2024 and 2025, due in part to capacity price increases in PJM.[18] By contrast, customers of utilities that rely on long-term integrated resource planning, rather than the PJM capacity market, were far less exposed to PJM capacity price increases. Customers of Dominion Energy, which owns generation, experienced only a minor rate impact when capacity prices in Dominion Energy's region of PJM rose by 798% between 2023/24 and 2024/25.[19]

Several factors contributed to the recent capacity price increases in PJM. A key factor was the surge in data center demand expected in PJM, which increased PJM's projected capacity needs. New capacity resources in PJM have also been slower to enter and more costly for various reasons, including interconnection queue delays and higher costs to build new power plants. Additionally, PJM's capacity market structure does not permit PJM to assign the incremental costs of serving new data centers to certain customers. Instead, all PJM customers in a given zone pay the same price for capacity.[20] In contrast, the large load tariffs and agreements discussed above can directly assign the costs of the capacity built to serve data centers to the data centers themselves, protecting the utility's other customers from paying the costs of serving new data centers. In January 2026, the governors of the PJM states, the Secretary of Energy, and the Secretary of the Interior signed an agreement to extend caps on the capacity prices that retail customers will pay, support the development of new generation capacity for data centers, and ensure that data centers pay for that capacity.[21]

5. Conclusions and recommendations

This study supports the following conclusions:

1. ***First***, we conclude that prevailing narratives suggesting there is a nationwide trend in retail rates are not entirely accurate. There is no single trend that meaningfully captures the trajectories that retail electric rates have taken in the past five and ten years. Rather, rates have changed because of factors that vary from region to region.

2. ***Second***, for most American customers, rates have been fairly stable. In many cases, rate changes have been consistent with inflation; in some cases, the change has been less. One implication of this result is that efforts to contain utilities' costs have generally been effective.

3. ***Third***, utility rates in the Northeast have risen in the past few years because of increases in the wholesale cost of energy. In California, increases have been driven in large part by wildfires and wildfire mitigation. For some California customers, costs associated with the state's rooftop solar program may have raised bills significantly. In much of the rest of the country, rates have been fairly stable.

4. ***Fourth***, where rates have increased, data centers have generally not been the cause. Customer protections designed to prevent that outcome in the future are being adopted by regulators across the country.

5. ***Fifth***, where rates have increased, the mechanism has been an increase in operational spending caused by factors beyond the control of utility management.

6. ***Sixth***, where rates have increased, they have not significantly enhanced utility earnings.

Specific recommendations that would enhance affordability are beyond the scope of this report. For reasons discussed above, we believe that investments in the Northeast that lower regional prices or reduce demand could help to lower rates, as could allowing utilities to own generation. In California, financial strategies aimed at reducing the cost of funding investments and spending on wildfire prevention and mitigation could benefit customers. In both cases, costs, benefits, and alternatives would need to be carefully considered, and other alternatives also merit consideration.

Notwithstanding the details of specific initiatives, this study clearly demonstrates the need for approaches to affordability that are tailored to the jurisdictions in which they will be implemented. There is no single trend in the US that explains how retail rates have changed, and there is no single solution that will apply in every situation. Rather, it is our recommendation that policymakers develop a clear understanding of the relevant trends and context in their locality before they commit to an intervention and, if they decide that action is necessary, to move forward with strategies and measures that will address the root causes of the challenges affecting customer affordability in their jurisdiction.

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1 The sources of data we used in this report and the methods by which we developed our analyses are described in these endnotes.

2 EIA Form EIA-861M collects monthly electricity sales (MWh) and revenues ($) by end-use sector (residential, commercial, industrial, transportation) from electric utilities, energy service providers, and distribution companies serving end users. Average revenue per MWh for residential sector is used as a proxy for retail electricity rates.

3 See, for example, the following:

Powerlines, *"Utility Bills Are Rising"* Q2 2025 *Update*, July 2025, link.

Atkinson, Will, RMI, *Volatility vs. Affordability: Globally, Renewables' Cost Advantage Grew Last Year*, August 13, 2025, link.

UtilityDive, *What's ahead for utilities: Navigating demand, AI and customer affordability*, December 15, 2025, link.

4 In some instances where relevant data are reported on a monthly basis, CRA calculated twelve-month averages for the period ending in October each year in order to use the most recent data available. Figure 1 does not include the District of Columbia, Alaska, and Hawaii.

5 Bureau of Economic Analysis, *Personal Consumption Expenditures*, Accessed December 2025, link.

6 Unitized costs were calculated by dividing cost categories by total electricity sales volumes, which are also reported in the Form 1s.

7 Many states conduct auctions on behalf of their retail customers, often referred to as Standard Offer Service auctions, that can hedge some, but not all, retail electricity costs.

8 A pass-through cost is one that a utility incurs and then recovers from customers on a dollar-for-dollar basis. There is no markup or profit included in a pass-through cost.

9 CRA calculated the load-weighted average price at the Independent System Operator of New England hub and the New York Independent System Operator's Hudson Valley Zone. From 2019 to 2024, the ISO-NE price rose from $33/MWh to $45/MWh while the NYISO price rose from $28/MWh to $41/MWh.

10 California Public Utilities Commission, *2025 Senate Bill 695 Report*, September 2025, link. See p. 29.

11 *Ibid*, p. 42.

[12] *Ibid*.

[13] *Ibid*, p. 43.

[14] California Lawmakers Pass Bill That Will Add $18B to Wildfire Reserves | TD World, link

[15] California IOU Combined Abstracts, November 2025, link

[16] Costs shared in this manner are usually recovered through rates on a volumetric basis. Because data centers consume large amounts of energy, a new data center customer could represent a significant portion of its host utility's total volumetric load.

[17] The benchmark capacity price in PJM is called the "Rest of RTO." The Rest of RTO price in the 2025/26 capacity auction, covering the June 2025-May 2026 period, was $269.92/MW-day, a $241.00/MW-day increase from the $28.92/MW-day price in the prior auction for the 2024/25 delivery period. The PJM Rest of RTO prices in subsequent capacity auctions for the 2026/27 and 2027/28 delivery periods were $329.17/MW-day and $333.44/MW-day, respectively.

[18] EIA, *Electricity Monthly Update*, link. The largest percent increases in average retail electric rates (not just residential) in the US between October 2024 and 2025 were in Maryland, up 18.4%, and Pennsylvania, up 17.5%. State-jurisdictional investor-owned utilities in these states are not permitted to own generation.

[19] Capacity prices account for less than 1% of a Dominion Energy customer's monthly bill. UtilityDive, *Dominion says ratepayers will be insulated from PJM capacity auction impacts*, August 7, 2024, link.

[20] Capacity prices can vary by location if transmission capacity is constrained between zones.

[21] Department of Energy, *Trump Administration Calls for Emergency Power Auction to Build Big Power Plants Again*, January 16, 2026, link.

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