



Retail Electricity Price Trends and Drivers:

Data Update—2026 Edition

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Objectives and Scope of Study

Context: Retail electricity prices are of national concern, but trends and drivers are complex and vary across states

Study Scope

Summarize trends in retail electricity prices

- National- and state-level trends (not utility-specific) since 2010, but focus on last year and since 2019
- Data sometimes presented in nominal terms but in most cases in real (inflation-adjusted) terms

Assess drivers of recent price changes

- Explores some of the most-common drivers of state-level price changes over the past year
- Describes relationships over longer period, 2019-25
- Does a deeper-dive on the impact of load growth

Study Limitations

- Is not definitive: analyzes subset of drivers from available data, **emphasizes need for continued research**
- **Does not analyze drivers in each individual state**; analysis focuses on broader trends
- Scope **is centered on retail prices**; studying bills and the costs and benefits derived from price increases are also important but not covered
- **Does not predict future** price trends or assess possible future price drivers, though does provide 2026 preview
- Focuses on understanding the nature and scope of price changes, **not measures to ameliorate any increases**

Findings underscore the **diverse set of retail price determinants** and highlight the need for continued efforts to inform policy and ensure affordability

Contents, Methods, and Data

- **Trends in retail electricity prices**
 - ▣ National & state-level trends: 2025 vs. 2010, 2019, 2024
 - ▣ Prices: all-sector average and residential prices
 - ▣ Affordability: costs relative to income & other expenses
- **Drivers of price changes from 2024 to 2025**
 - ▣ State-level price changes: all-sector avg. & residential
 - ▣ Primary drivers and story-lines from previous year
 - ▣ Longer-term context offered to understand latest year
- **Medium-term relationships: 2019 to 2025**
 - ▣ Update and expand data on medium-term relationships
- **Deep dive: impact of accelerated load growth**
 - ▣ Longer- and shorter-term impacts
 - ▣ State and regional case studies
- **Early 2026 indicators and IOU rate requests**
 - ▣ Early pricing data from 2026
 - ▣ Data on historical and recent rate increase requests
 - ▣ Other indicators suggesting near-term price increases

Primary Methods and Data

Synthesis of publicly available data¹

- EIA: retail prices, sales, generation
- FERC Form 1: investor-owned utility costs
- ISOs/mkt. monitors: trans., capacity, energy costs
- BEA/BLS/Census: income, expenditure, price index
- S&P: rate and ROE requests and approvals

Review of literature; case studies

- Regulatory filings & orders (wildfire & storm costs, case studies, year-over-year changes)
- Other literature (e.g., RPS & net-metering costs)

Selected timeframes for data synthesis

- 2025 vs. 2024 for the most recent, latest year
- 2025 vs. 2019 for trends that span COVID years
- 2025 vs. 2010 to provide longer-term context

¹ Unless otherwise specified, data and analysis includes all 50 states and DC. Inflation adjustment uses regional and national CPI data from BLS; adjusting for inflation based on other common price deflators does not make a material difference to the core findings and results.

Additions in this 2026 data update of retail price trends and drivers

This briefing deck **updates** and **builds** on [LBNL/Brattle’s 2025 work](#), which included a journal article, briefing materials, and a data tool; and [LBNL work published in 2024](#)

Broad updates and additions in this 2026 edition include:

Data updates to include retail price trends and drivers through year 2025
(most slides)

Enhanced focus on price trends from 2024 to 2025 and key YoY drivers
(slides 19-28)

Expanded focus on load growth, and impacts on retail electricity prices
(slides 46-58)

Additional data on IOU rate increase and ROE requests and approvals
(slides 59-65)

Expanded data related to retail price trends and drivers:

Data on electricity burden and affordability trends
(slides 10, 15-18)

Natural gas impacts over the longer- and shorter-term
(22-23, 40-41)

Regional capacity-prices and related impacts
(24-25, 44)

Regional transmission costs and related impacts
(27,32-33)

Regional distribution costs and related impacts
(26,31,33)

Carbon policy impact on generation costs
(38)

Coal and nuclear generation, relationship to prices
(42-43)

Utility ownership, regulation, and financing
(45)



Trends and Drivers of Retail Electricity Prices: Summary of Key Findings

The Crisis View



Nominal Prices Up 33% since 2019

National residential electricity prices surged from 2019 to 2025.



Regional Price Spikes

Larger increases in California and states in the Northeast & Mid-Atlantic.



High Electricity Burden

One-third of households dedicate over 5% of their income to electricity.



The More Nuanced View



Prices Largely Tracked Inflation

All-sector average prices are only up 3% since 2019 in real dollars.



Real Prices Down in 29 States

A majority of states saw a decline in inflation-adjusted prices (2019-2025).



Electricity Burdens Are Lower than in 2019 in Most Regions

Total bills as a fraction of income are near all-time lows



What's to Come

Record levels of IOU rate increase requests & regulatory approvals suggest additional near-term price increases absent policy/market actions.

REQUESTS

(2025)

\$18B

APPROVALS

of requests (2021-25)

64%

Primary Drivers of Inflation-Adjusted Price Increases

(2019-2025, focused on regions with significant price increases)



Distribution & Business Operations

CAISO +6.0¢

ISO-NE +0.8¢

NYISO +0.7¢



Transmission

ISO-NE +0.8¢

NYISO +0.6¢

CAISO +0.4¢

PJM +0.4¢



Clean Energy Policy

Some states in **ISO-NE, NYISO, PJM, CAISO** saw increases up to **3¢/kWh** due to RPS, NEM, and cap-and-trade

Additional State-Level Price Drivers



Customer Load

Load growth generally **reduced** average prices, but **not** in PJM starting in 2025.



Natural Gas

Longer term: reduced prices. 2025 vs 2024: increased prices.



Generation Mix

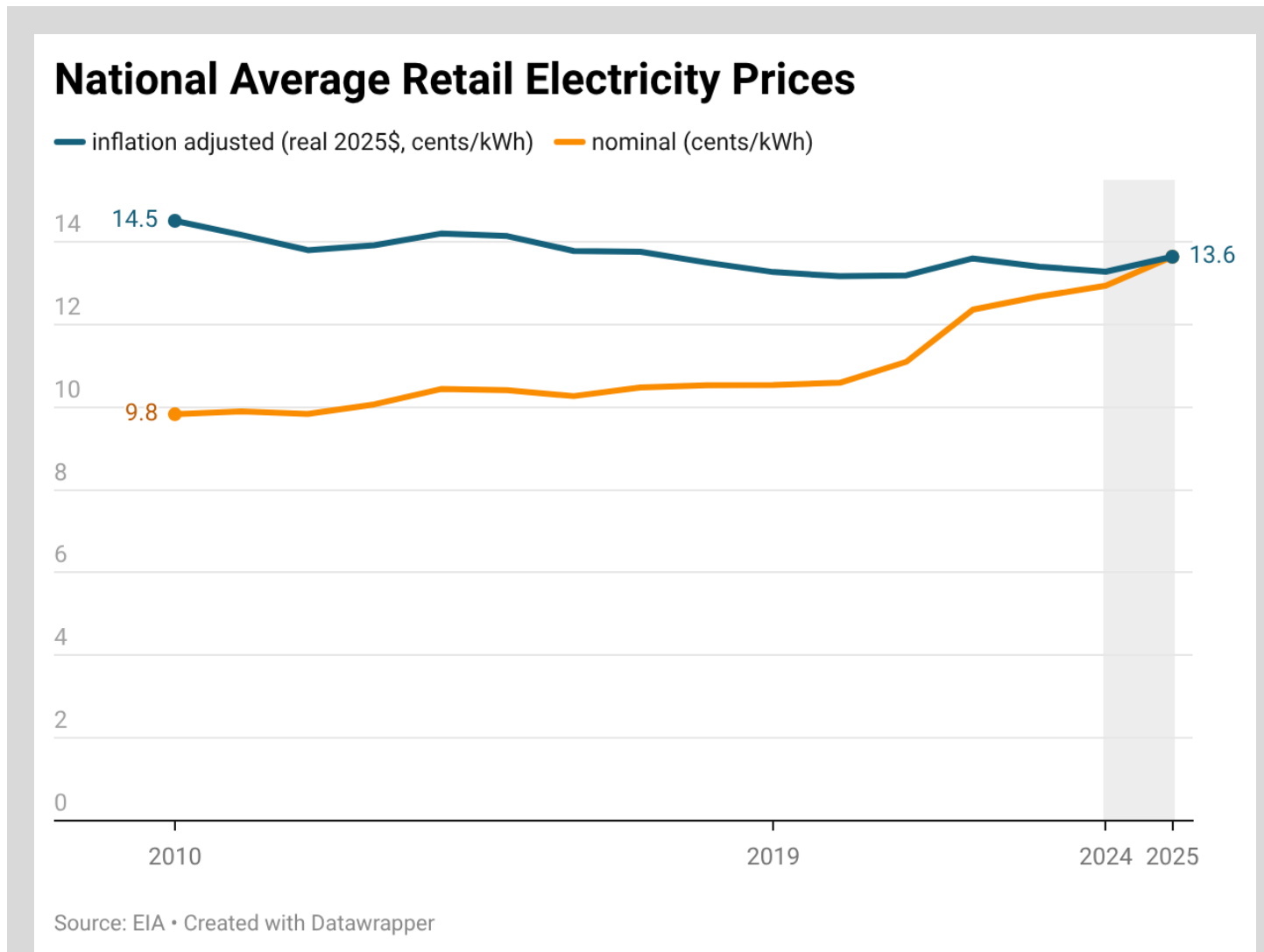
Some evidence that nuclear/coal and wind/solar (outside of RPS) put downward pressure on prices in some states.

Trends – *Level-setting on historical retail prices*

National-average nominal retail prices have spiked in recent years, though the increases have largely tracked inflation... but with a bump 2025

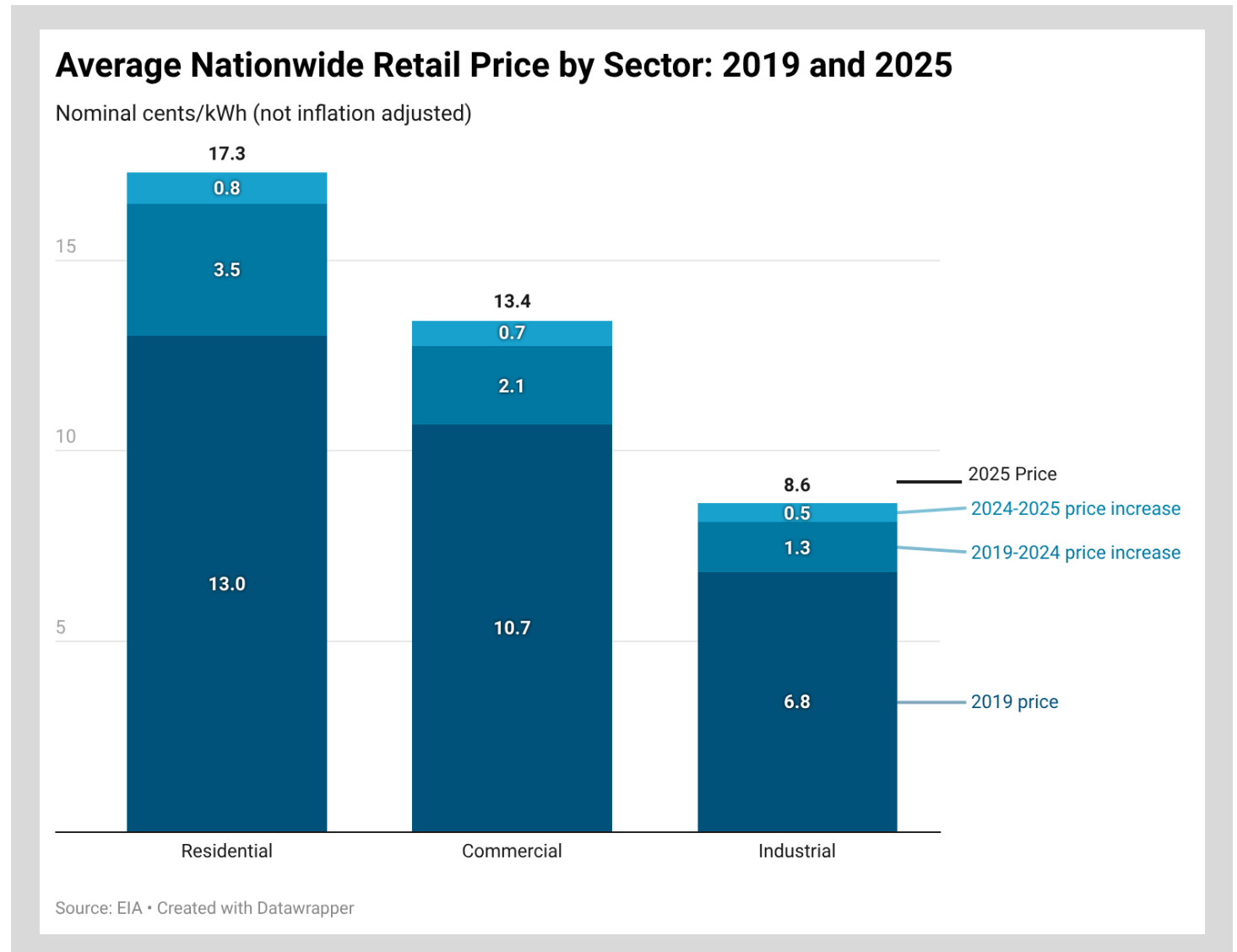
- All-sector average retail prices increased in 2025 vs. 2024: **5.3%** in nominal terms, **2.6%** in inflation-adjusted terms
- On a longer-term basis:
 - ▣ In nominal terms, average prices increased **29%** from 2019 to 2025, and **39%** since 2010
 - ▣ Adjusting for inflation, real prices in 2025 were **3% higher** than 2019, and **6% lower** than 2010
 - ▣ Note: Recently, electric costs have contributed 3-4% to overall inflation¹

Represents the “all-in” price, equivalent to total customer bills (including volumetric, demand, and fixed charges) divided by total retail electricity sales, and covers all costs associated with the provision of retail service (generation + transmission + distribution)



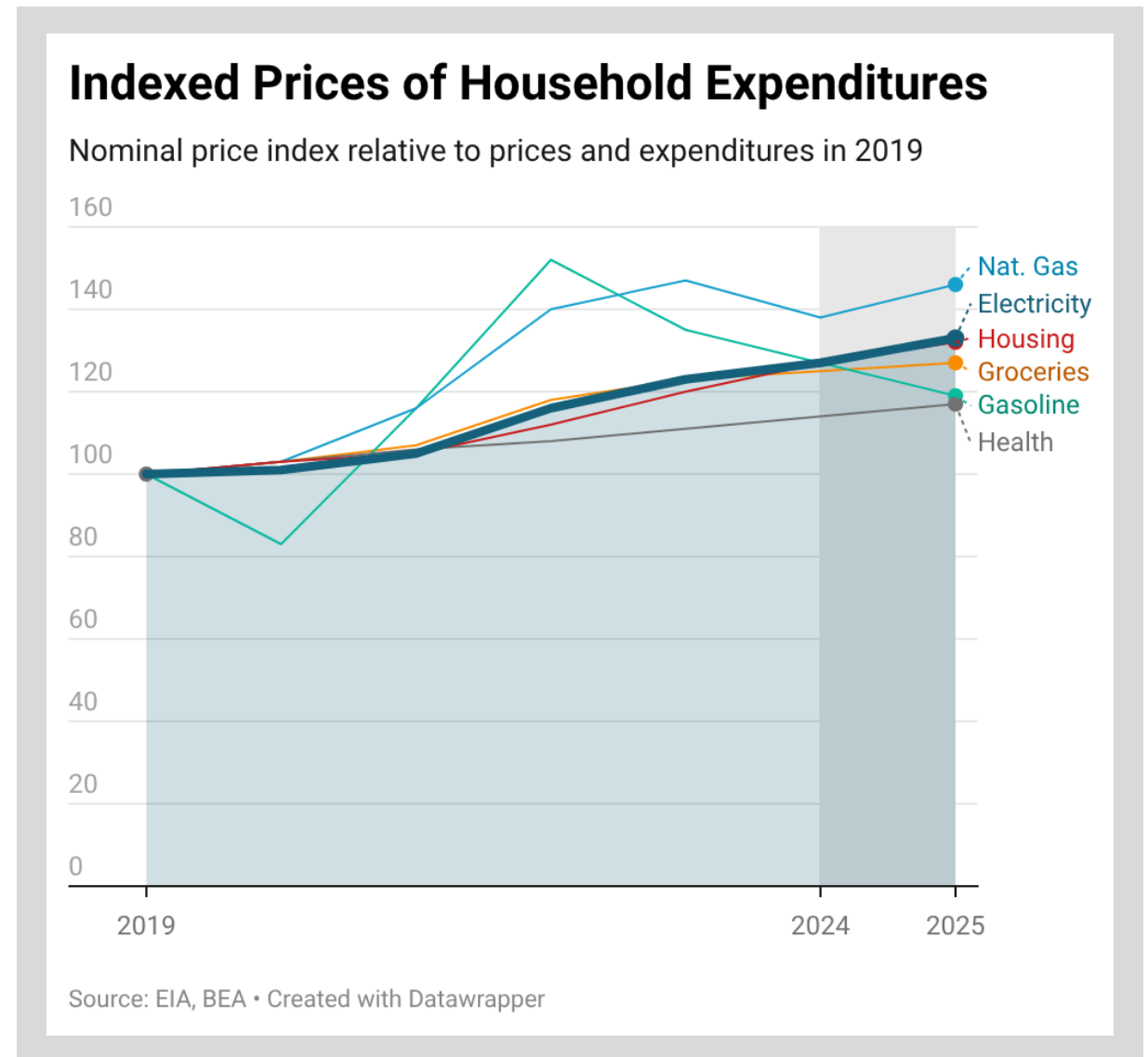
Residential customers have faced larger recent retail electricity price increases than have commercial and industrial customers

- Residential prices are higher and have risen faster than C&I
- From 2019 to 2025 (nominal):
 - ▣ Residential up: 33%
 - ▣ Commercial up: 26%
 - ▣ Industrial up: 27%
- Continues a longer-term trend of increasing gap between residential and C&I prices
- From 2024 to 2025 (nominal):
 - ▣ Residential up: 5.0%
 - ▣ Commercial up: 5.2%
 - ▣ Industrial up: 6.0%



Residential retail electricity price increases have been significant: broadly in line with some other household expenditures but higher than others

- ❑ The figure shows indexed residential electricity prices compared to other major household expenditures (not inflation adjusted) since 2019
- ❑ From 2019 to 2025, national-average residential electricity prices increased more slowly than residential natural gas, similar to housing, and more rapidly than health, gasoline, and groceries
- ❑ Broadly consistent with these trends, national-average residential electricity prices increased faster than economy-wide inflation from 2019 to 2025, rising 5.6% in real inflation-adjusted terms

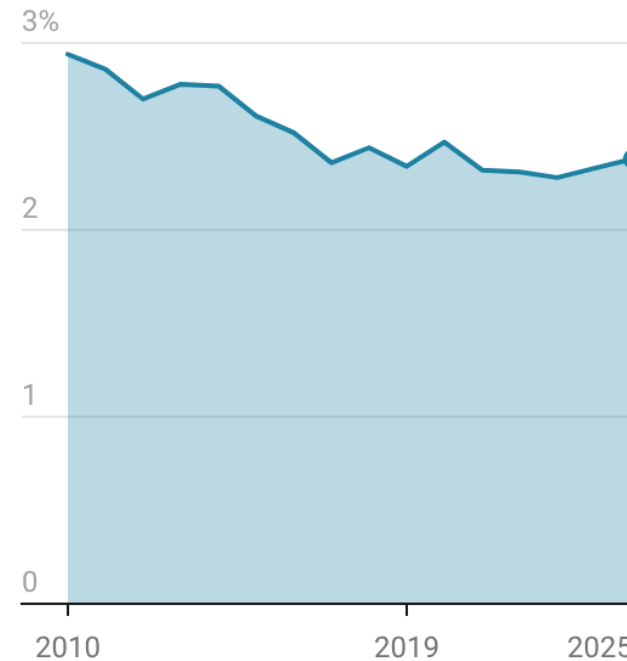


National residential electricity bills as a fraction of household expenditure (*left*) and income (*right*) trended down for decades, but increased recently

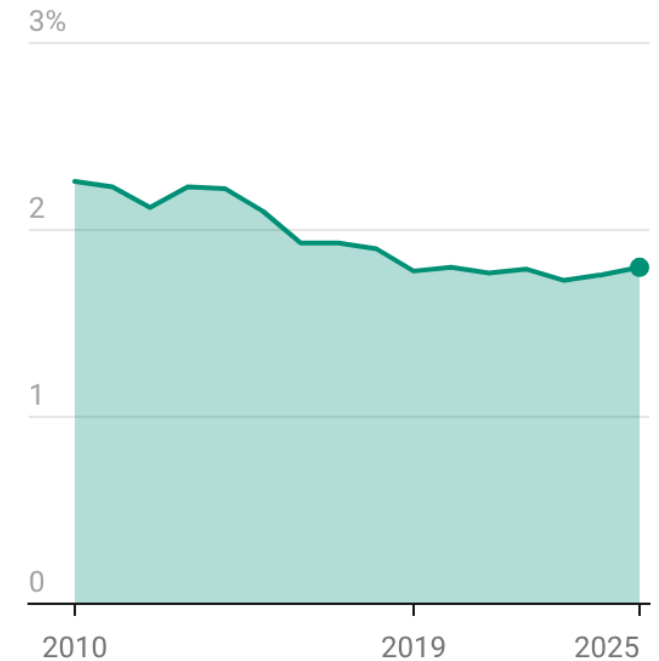
- Average residential bill as a fraction of total expenditure
 - ▣ 2.4% in 2025
- Average residential bill as a fraction of income before taxes
 - ▣ 1.8% in 2025
- In both cases, 2025 values:
 - ▣ are lower than in 2010,
 - ▣ are near all-time lows,
 - ▣ but are similar to 2019,
 - ▣ and have increased since 2023.

Average Residential Electricity Costs as a Fraction of Total Household Expenditures & Income Before Taxes

Residential Electricity Costs as a Percentage of Expenditures



Residential Electricity Costs as a Percentage of Income

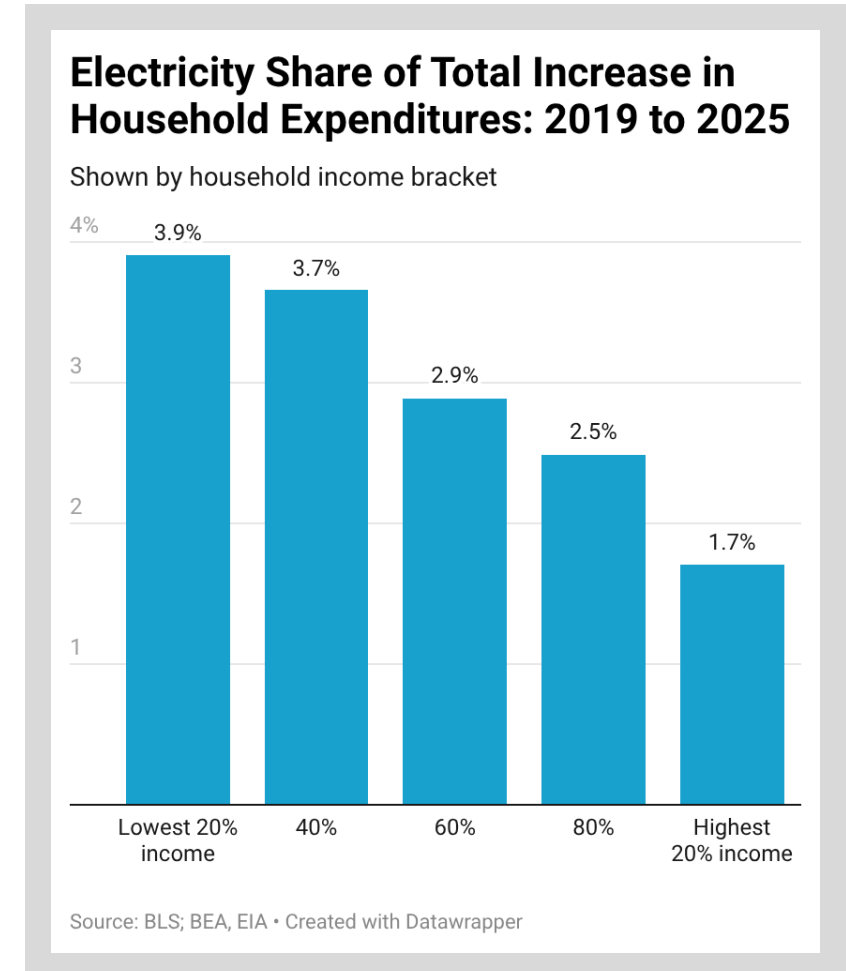
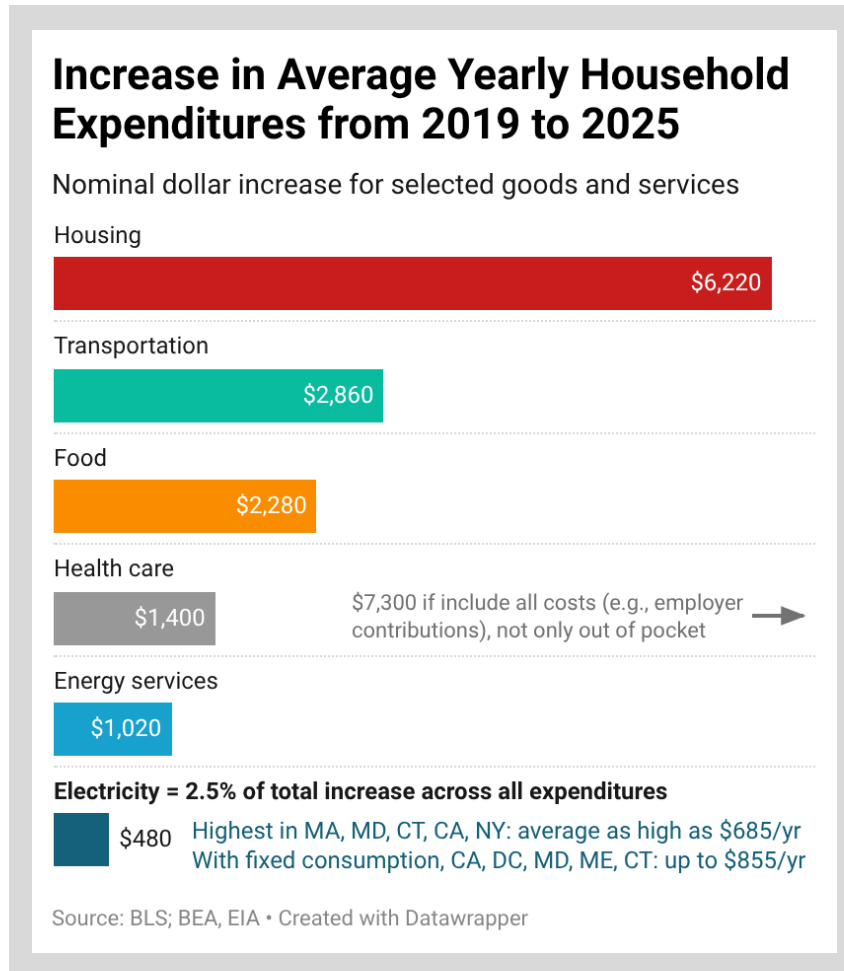


Data for 2025 are extrapolated based on data from BEA and EIA

Source: BLS Consumer Expenditure Survey • Created with Datawrapper

Nominal increase in average residential electricity bills since 2019 equals 2.5% of the overall increase in average household expenditures

- Average household expenditures, in total, increased by ~\$19,100/yr from 2019 to 2025, led by housing; average residential electricity bills increased by ~\$480/yr, **equal to 2.5% of the total**
 - ▣ Avg. pre-tax income increased by \$25,600
- Electricity's share of the total increase in expenditures was **greater for lower-income households**
 - ▣ Lowest 20% income: \$8,000 increase in average expenditure, \$310 from electricity
 - ▣ Highest 20% income: \$35,800 increase in average expenditure, \$610 from electricity



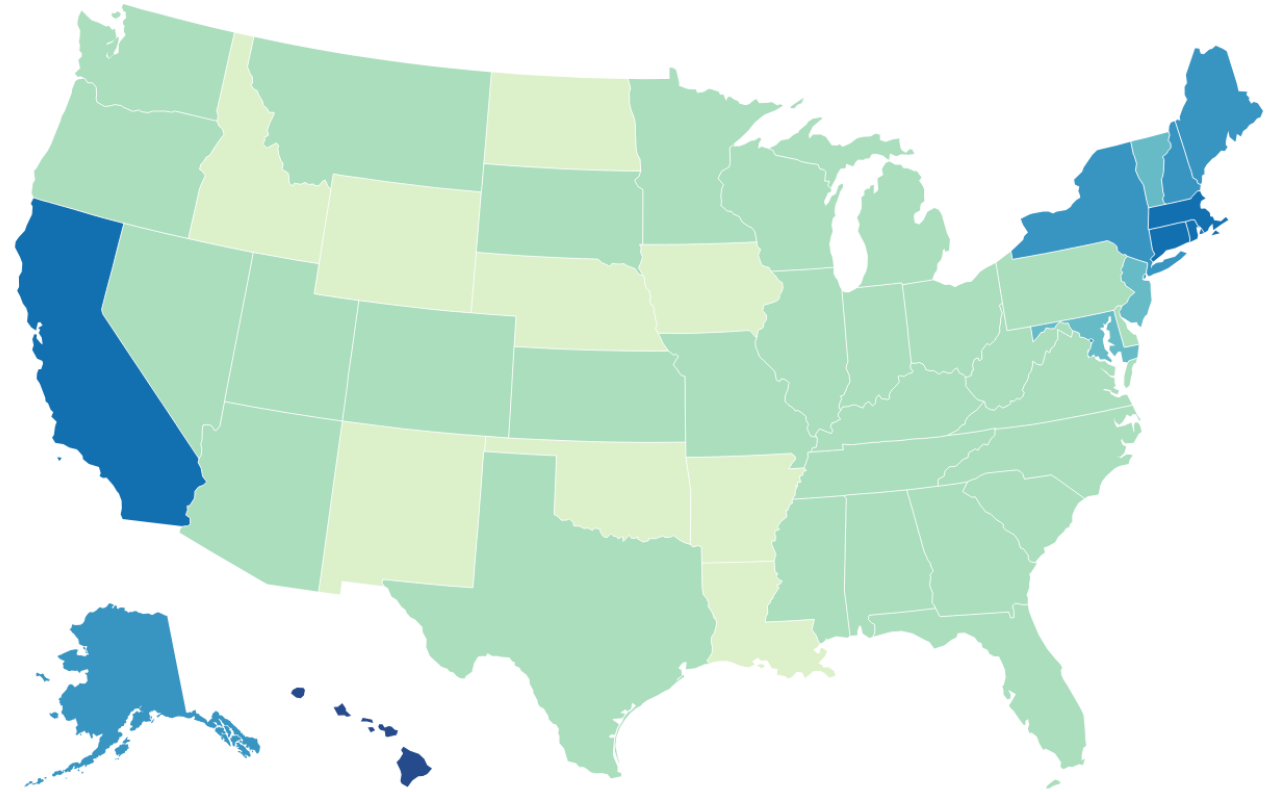
National trends mask stark differences in state-level all-sector average retail electricity prices in 2025

- Map depicts all-sector average retail electricity prices, in 2025
- Highest prices were in Hawaii, California, the Northeast, Alaska, some states in the Mid Atlantic
- Around 90% of the lower-48 landmass and ~75% of the population are located in states with all-sector average prices below 15 cents/kWh
- As shown earlier: residential electricity prices are higher than all-sector averages

Average Retail Electricity Price in 2025

Real cents/kWh (2025\$)

< 10 10–15 15–20 20–25 25–30 ≥ 30

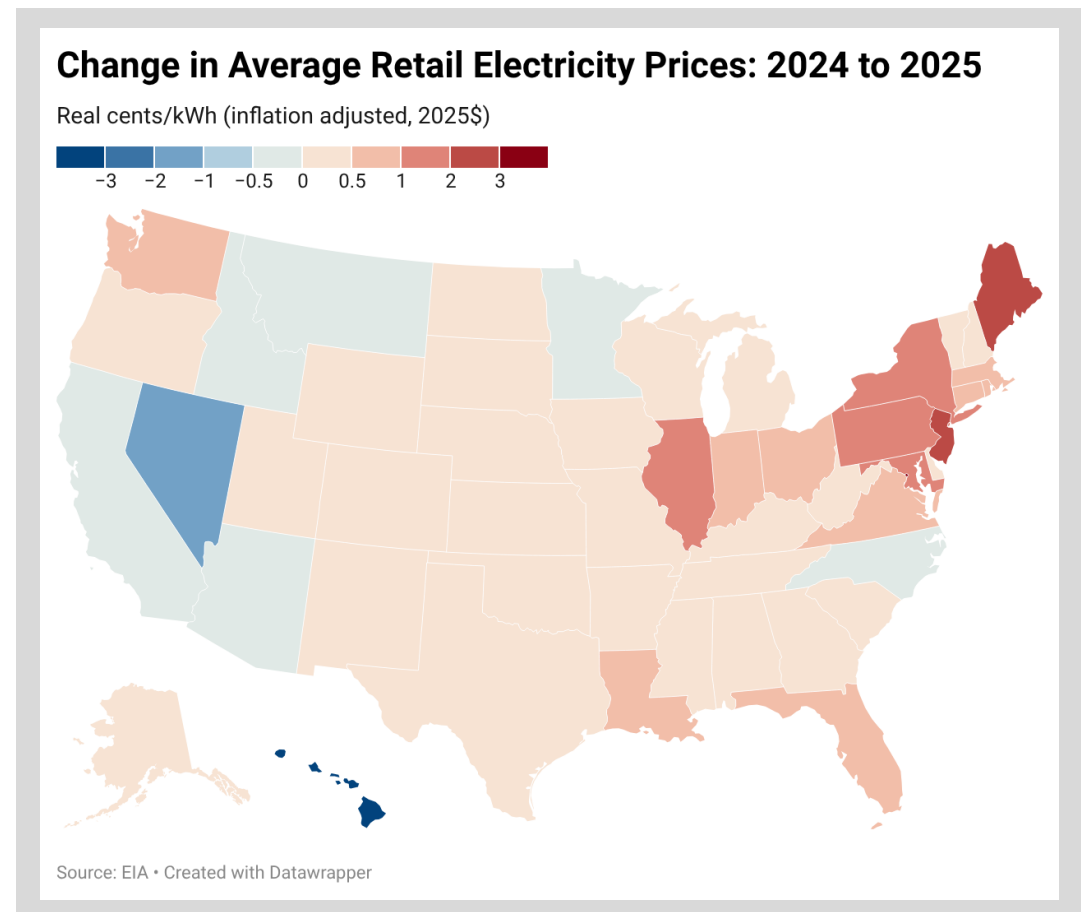
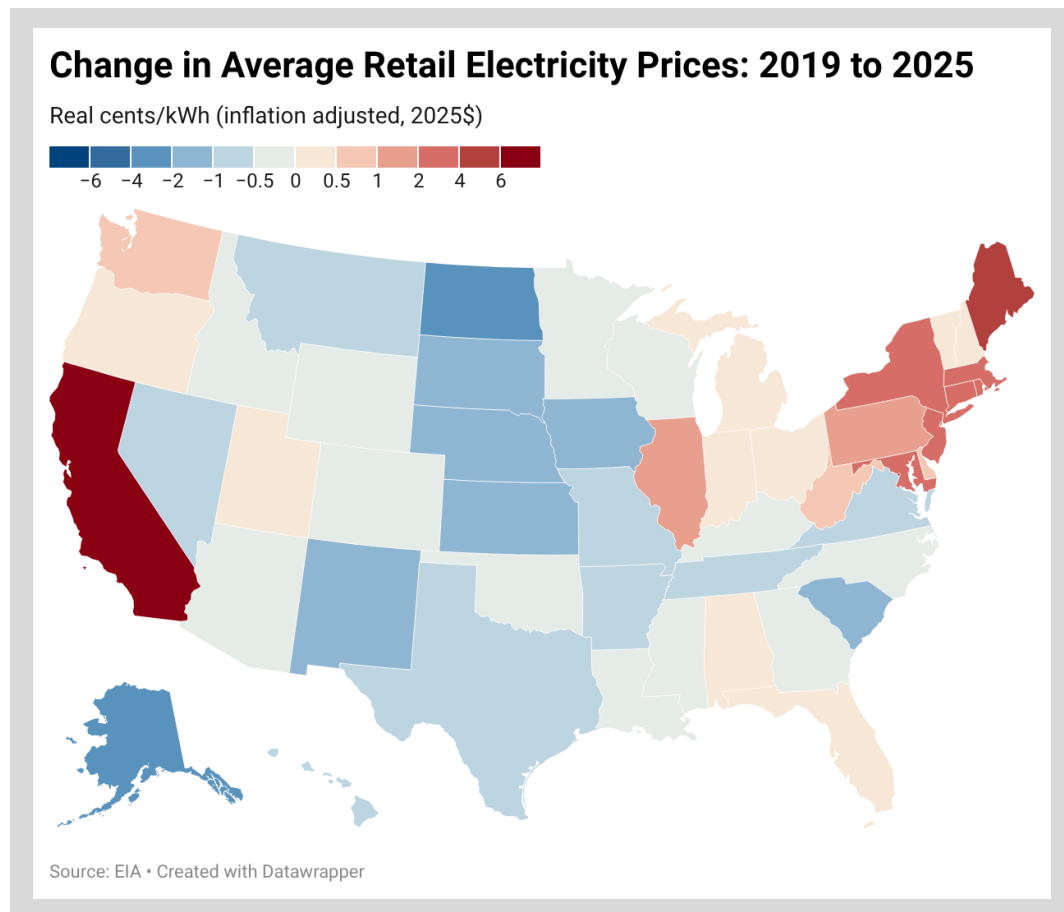


Source: EIA • Created with Datawrapper

Changes in average state-level, inflation-adjusted retail prices vary widely: many more states with increases in last year (*right*) than 2019-2025 (*left*)

2019-2025: 29 states with decreases; largest increases in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

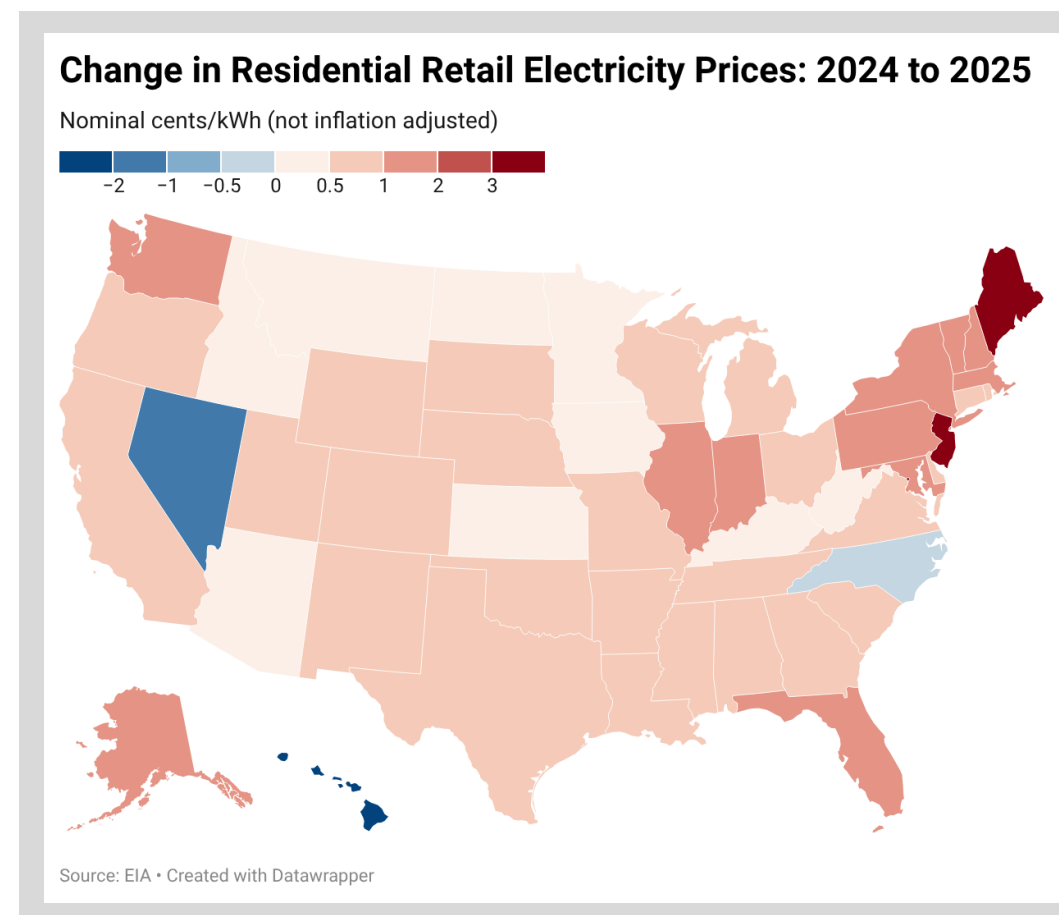
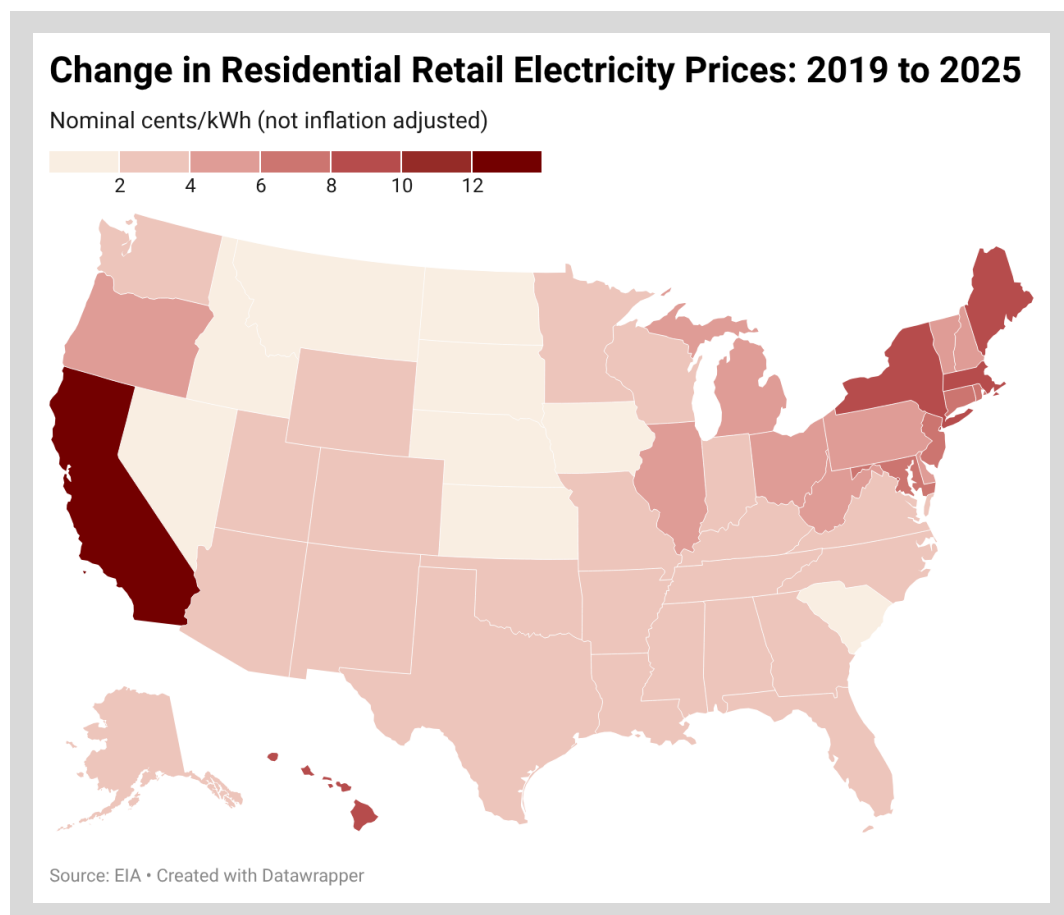
2024-2025: 43 states/DC with increases; largest increases in Northeast, Mid-Atlantic, Great Lakes, some in Southeast and West



Turning to residential prices, customers may pay more attention to rapid increases in nominal (*shown below*) than to inflation-adjusted retail prices

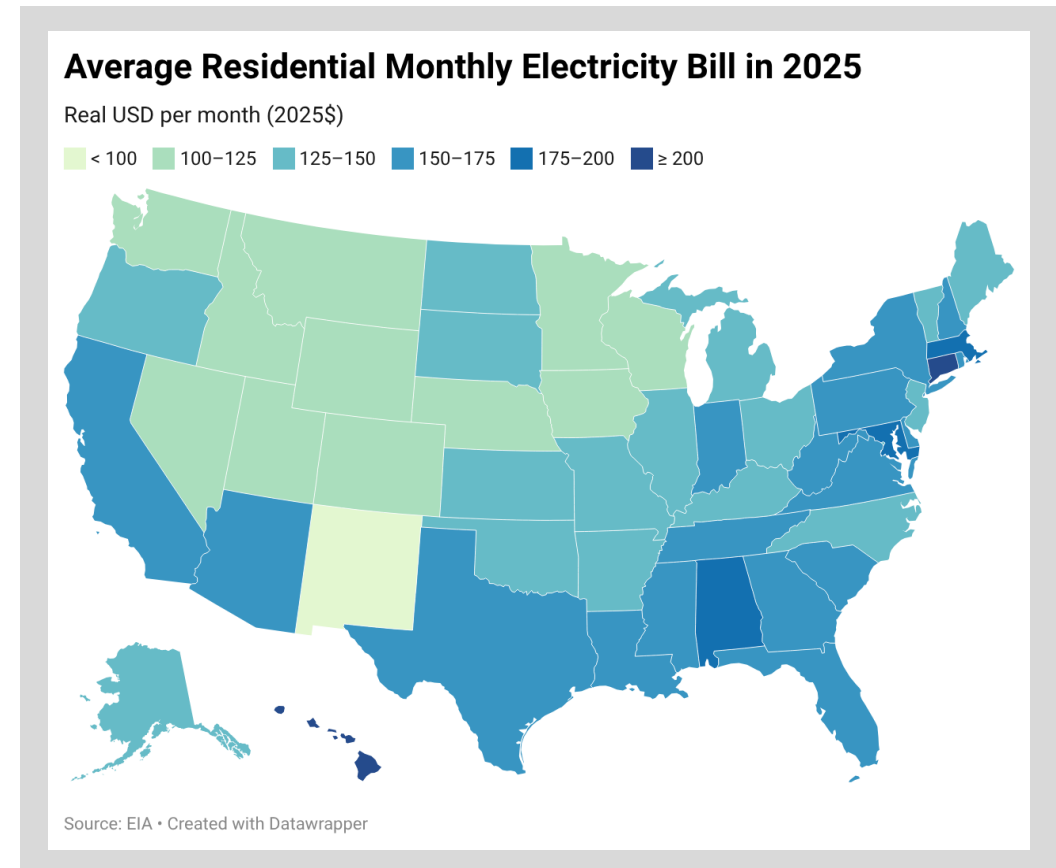
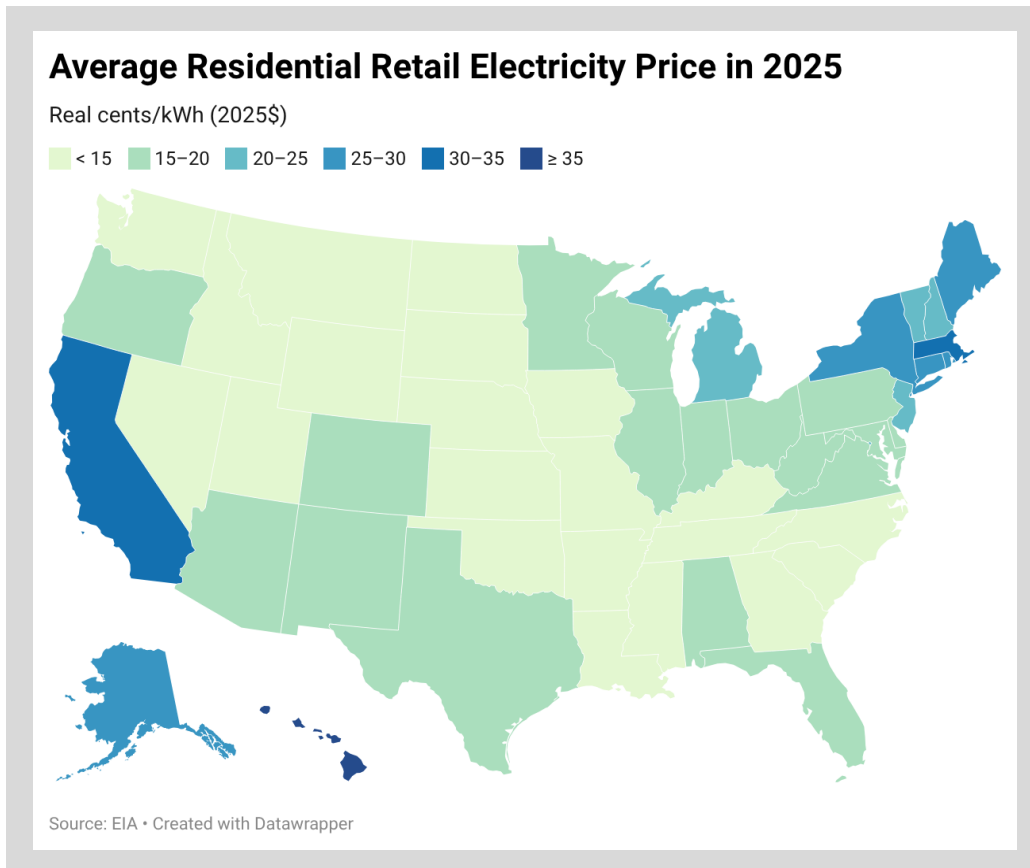
2019-2025: All states with **increases**; largest increases in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

2024-2025: Most states with **increases**; largest increases in Northeast, some states Mid-Atlantic, Great Lakes, Southeast, West



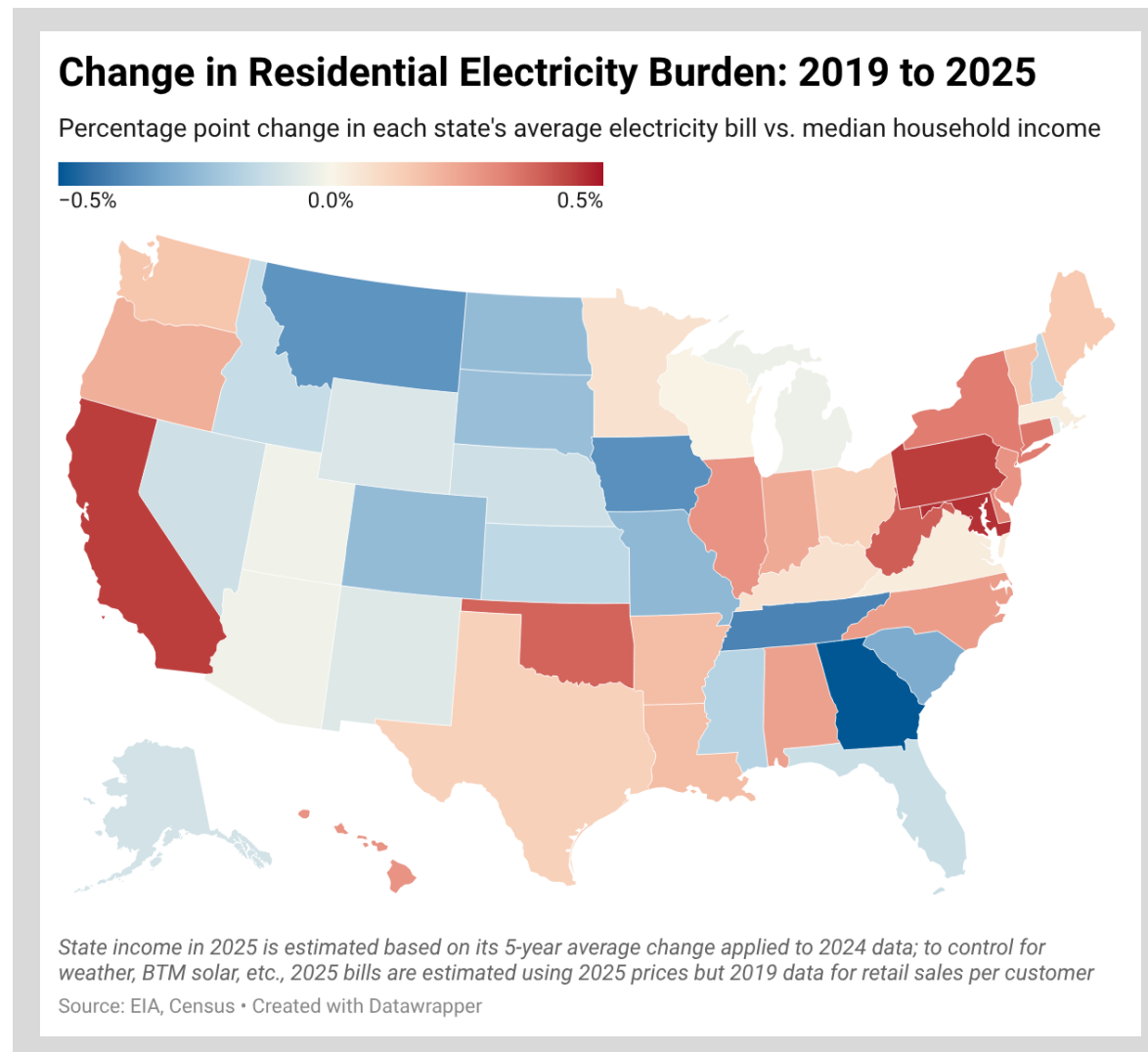
Household affordability is also impacted by consumption: states with the highest prices (left) in 2025 may not have the highest bills (right)

- The highest average residential **prices** in 2025 were in HI, CA, the Northeast, and Alaska
- Highest monthly **bills** occurred across a diversity of states; California not an outlier on bills
 - ▣ *Note that the residential bill figure is electricity-only, not all household energy, and is thus impacted by the prevalence of electric heating; states with more natural gas or fuel oil heating (notably, the Northeast, Midwest, California) have additional energy costs not shown here¹*



Average electricity burdens are impacted by residential electricity bills and by household income, and trends over time vary by state

- “Electricity burden”: Earlier slide depicted the national trend in average residential electricity bills as a share of income
- Shown here, there is substantial variation in state-level electricity burden trends¹
- From 2019 to 2025, electricity burdens **worsened in 27 states and DC**
 - ▣ DC: Up ~0.6 percentage points
 - ▣ MD, CA, PA: Up ~0.4 pct. points
 - ▣ WV, OK, CT, NY: Up 0.3-0.35 pct. points
- Electricity burdens **improved in 23 states**
 - ▣ Largest improvements in GA, TN, IA, MT, SC



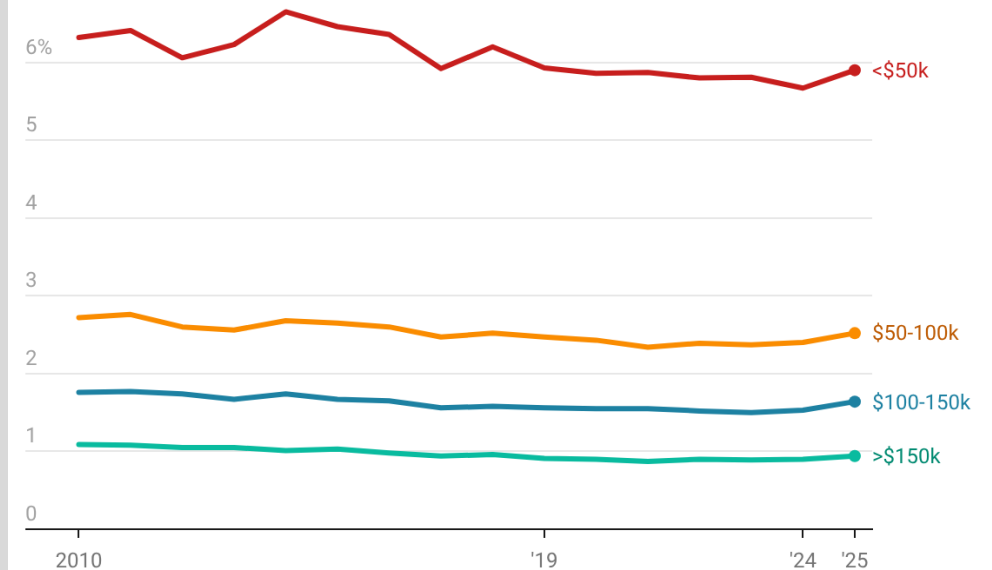
¹ Focused solely on electricity impacts, not broader concept of energy burden; data for this slide are based on average electricity bills from EIA and median household income from the Census

Regardless of aggregate national and state-level trends, electricity expenditures are a major hardship for some households

- Average electricity burdens are **over 5% for the one-third of households with incomes less than \$50k per year**¹
- Consistent with an earlier figure, burdens are lower than in 2010 but, in more-recent years, have stabilized... and then increased
- More broadly:
 - 1-in-6 households are behind on their energy bills; utility arrearages reached \$21 billion in May 2025²
 - Among a sample of 127 utilities (53M customers), disconnection rates declined from 2019 (~0.5%) to 2020 (~0.1%) with pandemic-related protections; they have since increased but remained below 2019 levels through the end of 2025 (~0.4%)³

Residential Electricity Bills as a Fraction of Income, by Household Income Bracket

Electricity burden for average household in each income bracket



Note that 2025 values are projected based on regional EIA electricity bill data and BLS income trends, and are subject to revision. Figure excludes the bottom and top quartiles of data in each income bin to create more stable results. Data are from the BLS Consumer Expenditure Survey. Electricity costs are based on respondent reports of costs over three-month periods and likely entail some recall error. Because the survey data are not panel data, some changes over time may reflect spurious changes in the underlying sample. Results should be interpreted with care.

Source: BLS • Created with Datawrapper

¹ Focused solely on electricity impacts, not broader concept of energy burden; based on BLS's "Consumer Expenditure Survey" with projections for 2025; ² NEADA (2026); ³ Carley & Konisky (2026)

Regional electricity burdens from 2019 to 2025 improved in some regions but worsened in others, with some differences based on household income

From 2019 to 2025, regional electricity burdens (a contributor to energy burden) **increased the most** in the Mid-Atlantic and Pacific regions (the latter greatly impacted by California)

LOWER INCOME

Change in Electricity Burden for Households with Incomes Below 80% of Regional Medians: 2019 to 2025

Percentage change in electricity costs vs. income for lower-income households

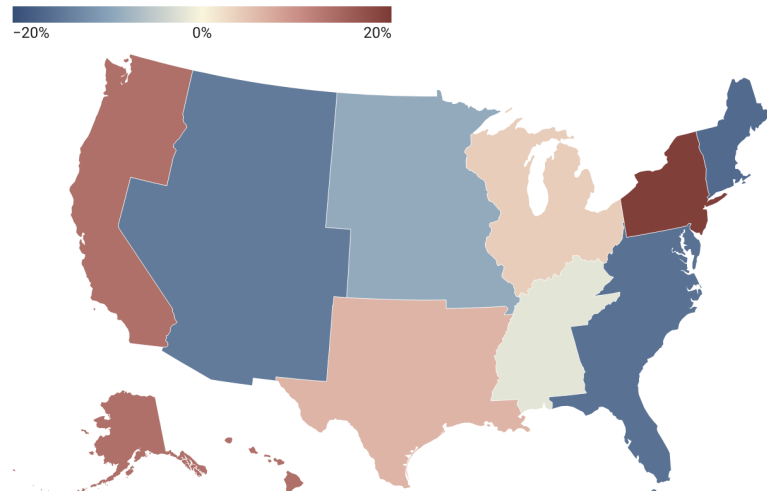


Figure shows the percentage change in the average electricity burden from 2019 to 2025 for lower-income households, excluding the bottom and top quartiles of data to create more stable results. Data are from the BLS Consumer Expenditure Survey, but projected for 2025. Electricity costs are based on respondent reports of costs over three-month periods and likely entail some degree of recall error. Because survey data are not panel data, some changes may reflect spurious changes in the underlying sample. Results should be interpreted with care.

Source: BLS • Created with Datawrapper

HIGHER INCOME

Change in Electricity Burden for Households with Incomes Above 80% of Regional Medians: 2019 to 2025

Percentage change in electricity costs vs. income for higher-income households

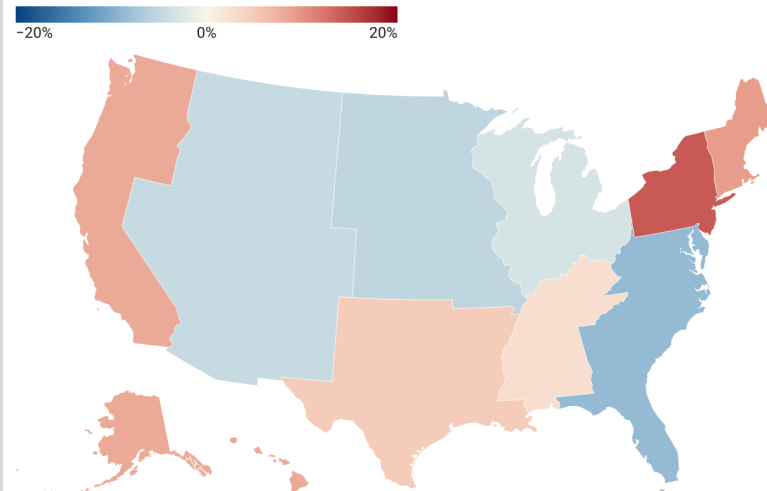


Figure shows the percentage change in the average electricity burden from 2019 to 2025 for higher-income households, excluding the bottom and top quartiles of data to create more stable results. Data are from the BLS Consumer Expenditure Survey, but projected for 2025. Electricity costs are based on respondent reports of costs over three-month periods and likely entail some degree of recall error. Because survey data are not panel data, some changes may reflect spurious changes in the underlying sample. Results should be interpreted with care..

Source: BLS • Created with Datawrapper

In New England, these data suggest worsening burdens for higher-income but improving burdens for lower-income households from 2019-2025; could be due to expansion of low-income bill assistance

Maps show changes in regional average burden for households with incomes < 80% (left) and > 80% (right) of regional medians (state-level data not available)

Focused on electricity burden not broader concept of energy burden; based on BLS's "Consumer Expenditure Survey", with data projected for 2025.

Even modest increases in electricity burden may pose energy insecurity risks for vulnerable households

- High inflation from 2021-2023 caused widespread increases in prices for many products, and survey data suggest that households remain concerned about price increases. In this context, even modest increases in electricity prices may pose issues for vulnerable households.
- U.S. Census data show that, among the 33 percent of households earning less than \$50k/year, **~12-19% report energy insecurity** within the last two months across three metrics: reducing other expenses, maintaining unsafe temperatures, and being unable to pay energy bills.
- Among the 11 percent of low-income households that report feeling "very stressed" about rising prices in general, the incidence of energy insecurity grows to **22-35%**.
- *Note: the survey addresses energy insecurity, not limited to electricity. Results from other related survey efforts, including EIA RECs and Census Household Pulse, vary.*

Measures of energy insecurity based on household survey data

Percent of households that express various types of insecurity within previous 2 months. 77% of sample fall in >\$50k income group, 23% in <\$50k, and 6% in <\$50k and financially stressed.

	Reduced necessary expenses to pay for energy	Maintained unsafe or unhealthy home temperatures	Unable to pay energy bills
>\$50k/yr household income	8%	7%	9%
<\$50k/yr household income	19%	12%	17%
<\$50k/yr income & financially stressed	35%	22%	31%

"Financially stressed" = households that reported that price increases in the past 2 months felt "very stressful"

Source: Based on a sample of 11,047 respondents from the U.S. Census HTOPS Survey, March 2026 • Created with Datawrapper

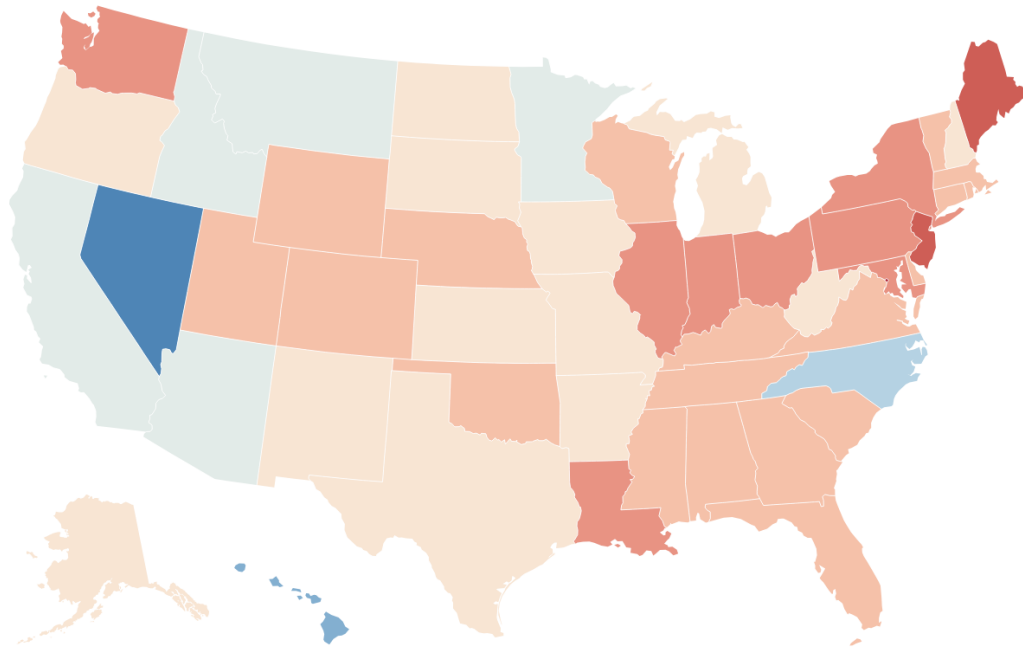
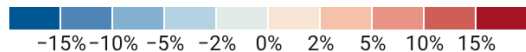
Drivers – *Understanding trends and variation over the last year ... but within a longer-term context*

Retail price increases from 2024 to 2025 outpaced inflation in most states: percentage change in real, all-sector average (*left*) and residential (*right*)

ALL-SECTOR AVERAGE

Percentage Change in All-Sector Retail Electricity Prices: 2024 to 2025

Percentage change, adjusted for inflation in 2025\$

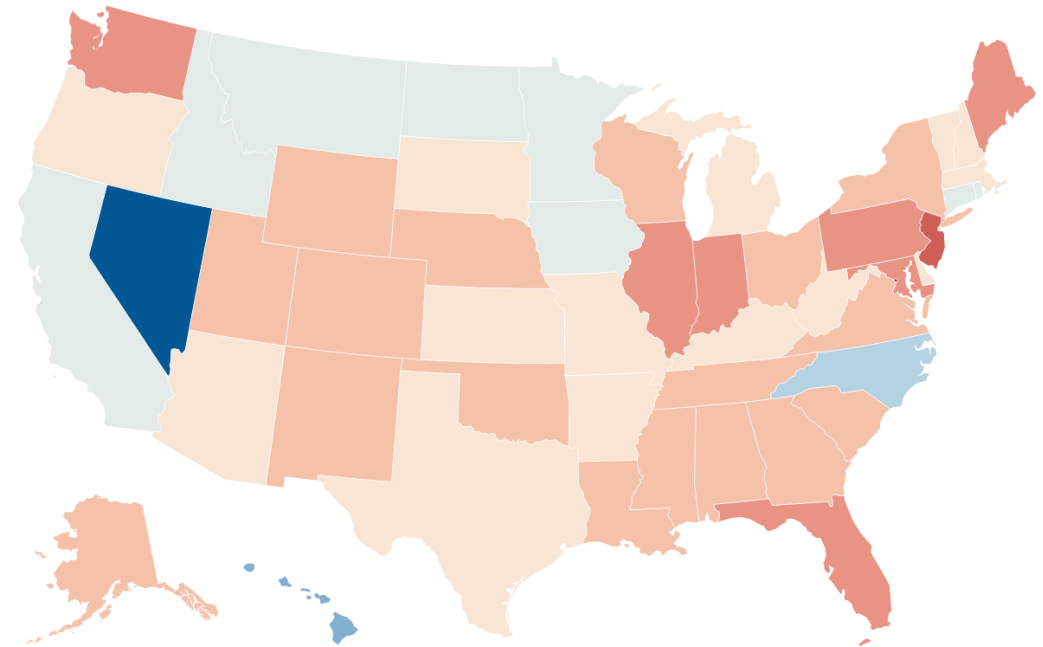
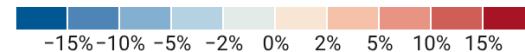


Source: EIA • Created with Datawrapper

RESIDENTIAL

Percentage Change in Residential Retail Electricity Prices: 2024 to 2025

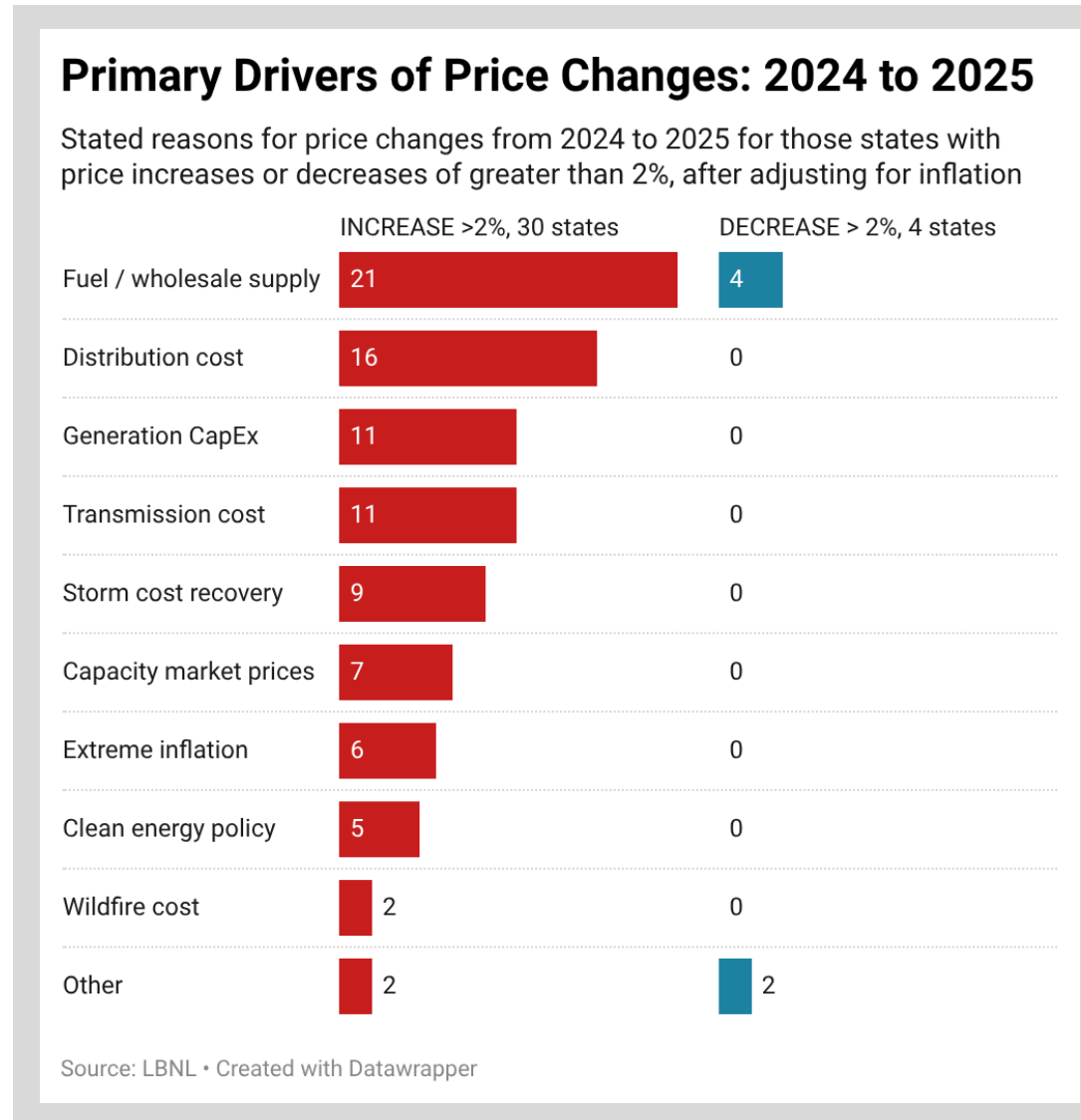
Percentage change, adjusted for inflation in 2025\$



Source: EIA • Created with Datawrapper

Primary YoY drivers: fuel & wholesale supply; distribution costs; cost of new generation; transmission costs; storm recovery; capacity prices

- Focused on states with larger inflation-adjusted price increases (>2%, 30 states) or decreases (>2%, 4 states)
- Reviewed filings, rate cases, tariffs, news, press releases, other analyses to broadly assess the primary drivers for year-over-year (YoY) all-sector average price changes
- Figure summarizes our assessment for states with **increases (red)** or **decreases (blue)**

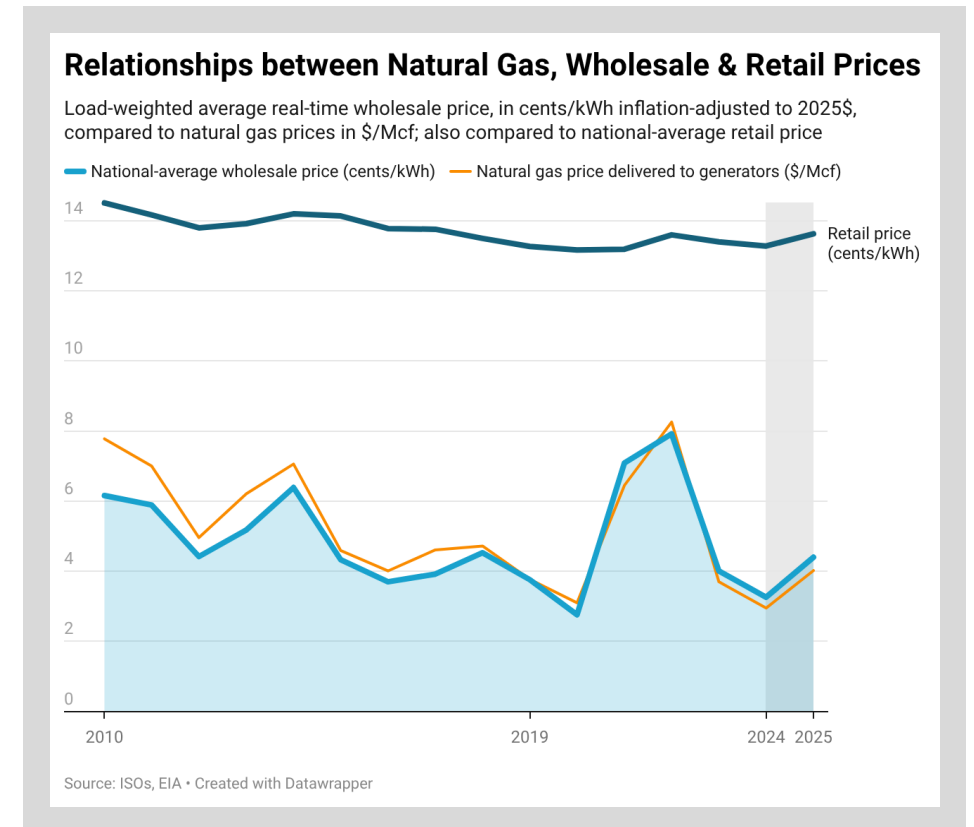
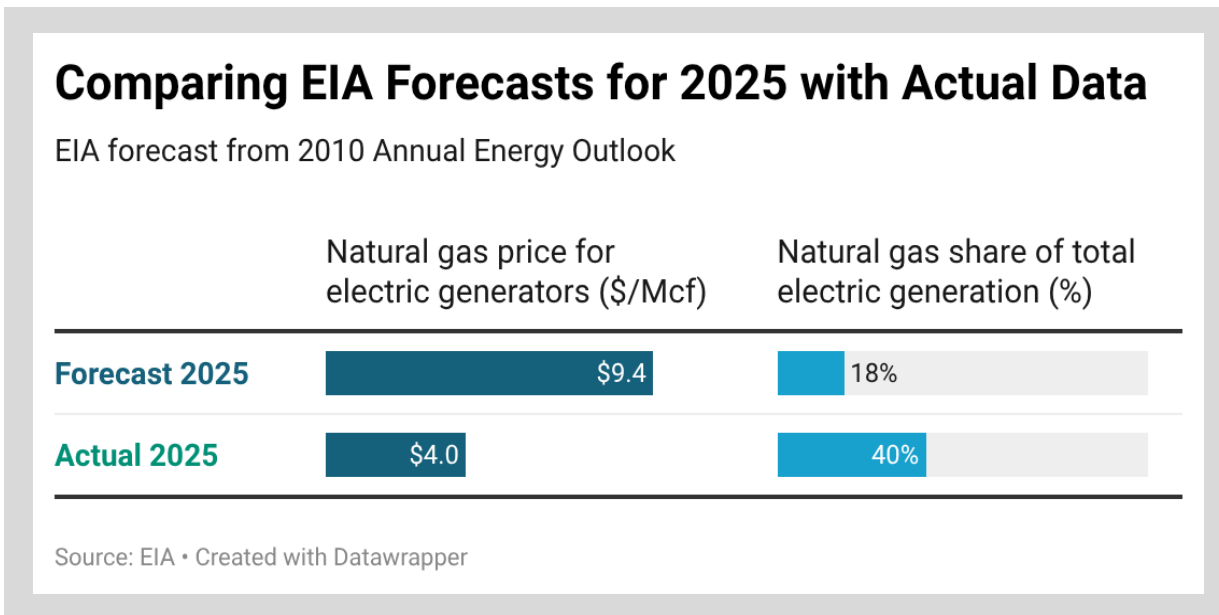


The few states that experienced larger reductions in inflation-adjusted prices largely did so via lower fuel prices (sometimes from delayed reductions after previous increases at the onset of the Ukraine-Russia war)

Note: YoY trends are subject to various state ratemaking idiosyncrasies and will tend to emphasize certain drivers over others; drivers reported for individual states are likely to change in future years and vary if assessed over longer time periods

The availability of low-cost natural gas has historically placed downward pressure on generation costs, wholesale prices, and retail prices

- Figure on left depicts EIA’s 2010 projection for 2025 natural gas prices and generation shares, and contrasts those projections with actual 2025 data
 - *Key point:* Technological advances resulted in substantially lower natural gas prices than previously expected, leading to a dramatic rise in natural gas generation → reflecting its economic competitiveness
- Figure on right shows national-average wholesale electricity prices over time vs. natural gas & retail prices
 - *Key point:* Wholesale (& retail) prices track gas, with year-to-year volatility, but with **reductions** in inflation-adjusted terms



Fuel prices in 2025 increased from their 2024 lows, pushing wholesale power prices higher—and thereby also increasing retail prices in 2025

- In 2025, the national-average price of natural gas delivered to electric generators increased 36% from the all-time low in 2024, pushing generation costs and real-time wholesale electricity prices higher
- Among ISOs, wholesale price increases were greatest in ISO-NE (+2.9 ¢/kWh), NYISO (+2.7 ¢/kWh), PJM (+1.6 ¢/kWh), and MISO (+1.3 ¢/kWh) – in each case, closely tracking regional gas price increases
- ERCOT and SPP wholesale electricity prices also modestly rose; CAISO prices were flat
- The impact of gas price variability on retail electricity prices depends on: gas share of generation, pipeline constraints, fuel & power hedging practices, degree of participation in wholesale markets, and regulatory lags in how fuel & purchased power costs pass through to end-use consumers
- Nonetheless, increased gas prices and its impact on generation costs and wholesale prices was a driver of YoY changes in retail prices in **21 states**, especially in ISO-NE, NYISO, PJM, and MISO

Wholesale Prices and Impact of Fuel Costs: 2025 vs. 2024

Load-weighted average real-time wholesale price and price change in cents/kWh, inflation adjusted to 2025\$, compared to year-over-year change in regional natural-gas hub prices

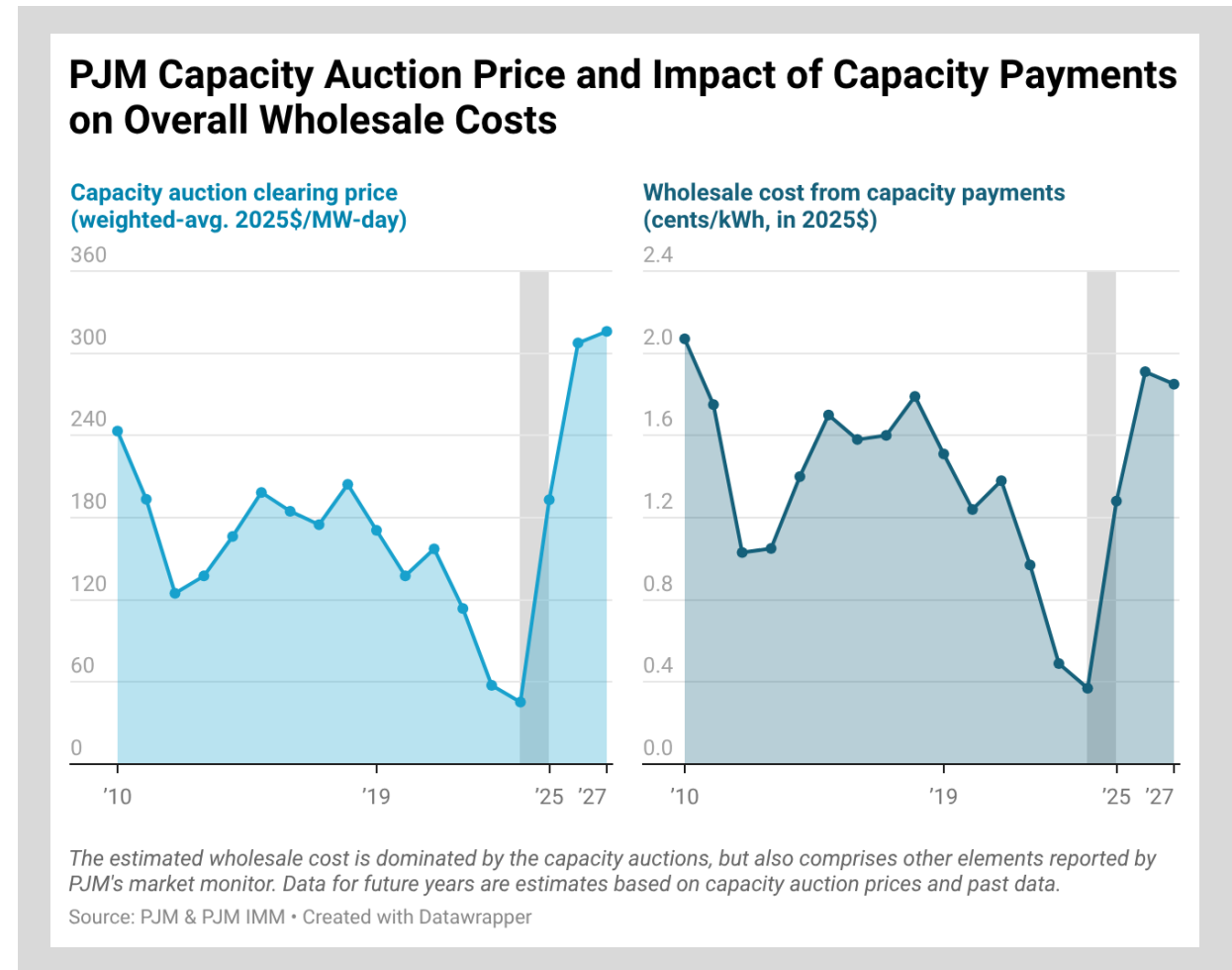
Region	2024: wholesale electricity price	2025: wholesale electricity price	Change in wholesale price (cents/kWh) ▼	Change in natural gas price (\$/Mcf)
ISO-NE	4.4	7.3	2.9	3.4
NYISO	3.9	6.6	2.7	3.1
PJM	3.5	5.1	1.6	1.6
MISO	3.0	4.3	1.3	1.1
ERCOT	3.0	3.3	0.4	1.2
SPP	2.6	2.9	0.3	1.2
CAISO	3.6	3.4	-0.1	0.7
National	3.3	4.4	1.2	1.1

Source: ISOs, EIA, Hitachi • Created with Datawrapper

Notes: Wholesale electricity prices are averages of hub prices. Natural gas prices are also regional hub prices, except that national prices are as delivered to electric generators.

Increases in capacity prices in the PJM region in 2025 were a significant contributor to the rise in YoY retail prices in many mid-Atlantic states

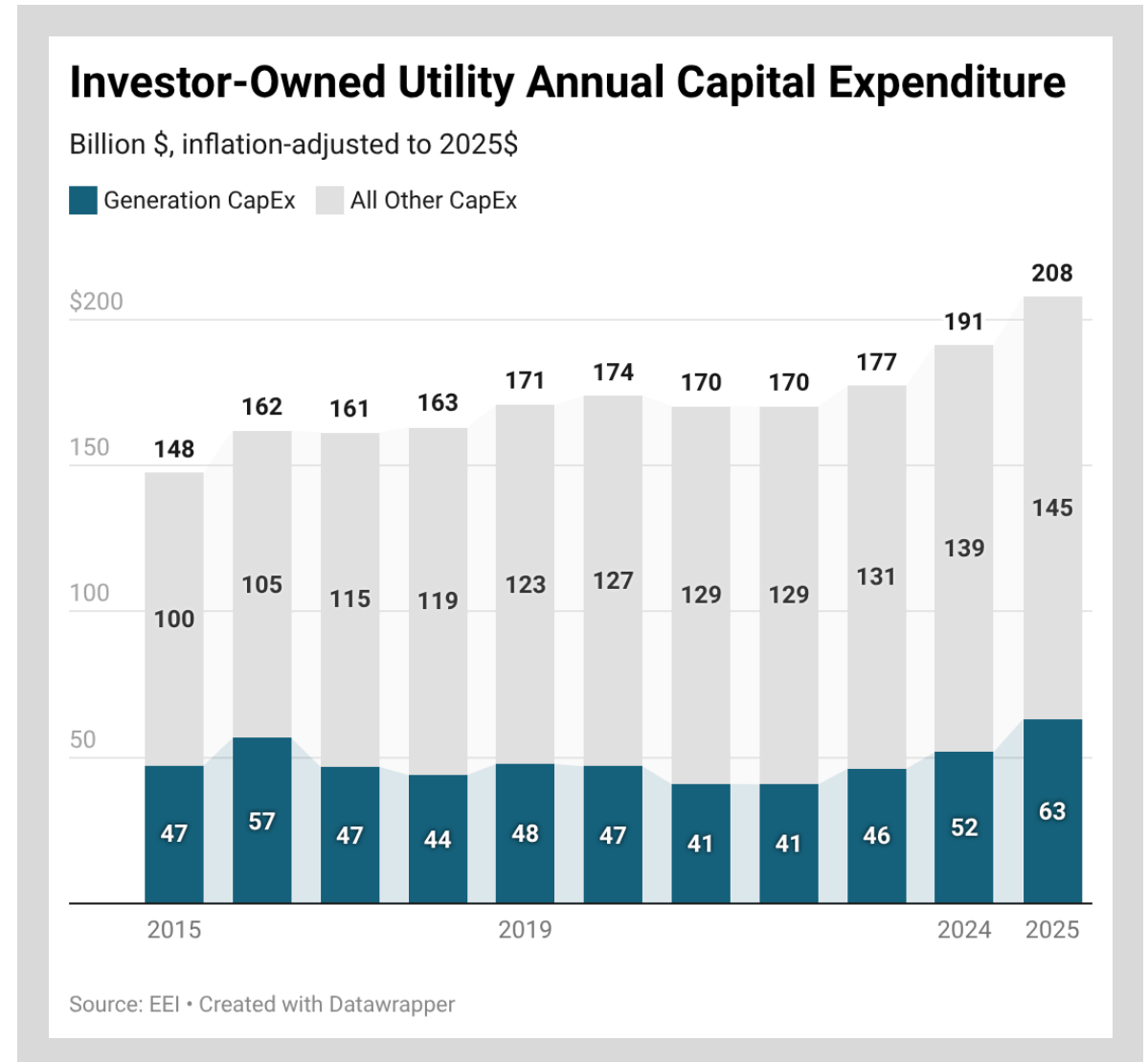
- Many PJM states saw large price increases in 2025 vs. 2024: DC (3.1 ¢/kWh), NJ (2.0), MD (1.5), IL (1.2), PA (1.2), IN (0.9), OH (0.8)
- In part, this is due to increases in PJM’s capacity auction prices since their low in 2024 (*left figure*)
- Capacity costs drove average PJM wholesale costs up **0.9 ¢/kWh** in 2025 vs. 2024; an additional **0.6 ¢/kWh** impact is expected in 2026 (*right figure*)
- *Note on capacity markets: Utilities cannot always own their own generation in wholesale market regions. Capacity markets are additional to energy and ancillary service markets and are used to send supplemental price signals to generators that new supply is needed to meet electricity demand during periods of grid stress.*



Notes: (1) separate from capacity, wholesale energy costs increased 1.7 ¢/kWh from 2024 to 2025 as fuel prices rose; (2) the contribution of capacity payments to wholesale costs increased from its 2024 low, but did not greatly exceed earlier years and is comparable to some past experience in other ISOs (see later slide)

Increased generation CapEx influenced the YoY change in retail prices in a variety of states, in part driven by anticipated load growth

- Annual investor-owned utility (IOU) generation CapEx increased **22% in 2025** in inflation-adjusted 2025\$, after increasing **13% in both 2024 and 2023**
 - ▣ Following many years of flat CapEx spending
 - ▣ IOU CapEx is recovered over asset lifetimes, so price impacts are delayed, can grow w/ time
- Increased CapEx was driven by load growth, as well as supply-chain constraints and higher costs for most generation types
- CapEx impacted YoY prices in **11 states**, e.g.:
 - ▣ TN: TVA's 5.25% rate increase in late 2024 in part to fund construction of new generation
 - ▣ IN: Cost recovery for NIPSCO's investments in solar and storage resulted in a price increase
 - ▣ SC: Duke raised rates by 8.7% in late 2024 to cover cost of gas, nuclear, solar, and hydro



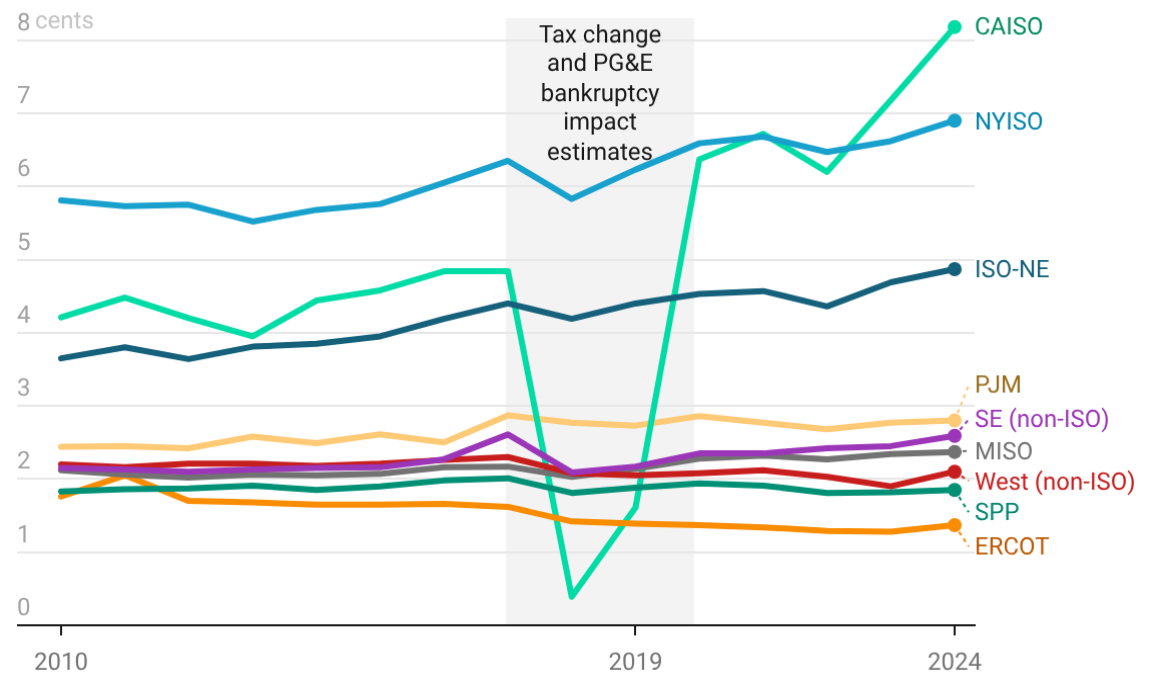
Note: Data prior to 2015 not available via latest EEI public data release

Distribution costs drove YoY retail prices higher in many states: age-based replacement at inflated prices, hardening, and storm cost recovery

- Our literature review ID'd **22 states** in which distribution costs increased retail prices from 2024 to 2025, some from storm recovery; e.g.:
 - Florida: 0.9-3.2 ¢/kWh temporary surcharge for storm cost recovery began in 2025 for 4 utilities
 - Central Maine Power: 2.5 ¢/kWh surcharge for storm cost recovery in 2025, up from 1.8 ¢/kWh in 2024
 - NYSEG: 0.9 ¢/kWh surcharge for securitized storm costs starting in 2025, to last up to 12 years
- California: Retail prices moderated in 2025 as wildfire mitigation costs declined for PG&E
- More broadly, the precise impact of distribution on YoY price changes is difficult to estimate consistently; the figure presents cost data from FERC, but data cannot be used to assess YoY price impacts and do not yet extend to 2025
- Focusing on the most-recent available years through 2024, cost growth was greatest in **CAISO, NYISO, ISO-NE; SE also climbing**

Estimated IOU Distribution Costs by Region: 2010-2024

Estimated average cost of distribution in cents/kWh, inflation adjusted to 2025\$; data are rough estimates of broad cost trends not precise yearly price impacts

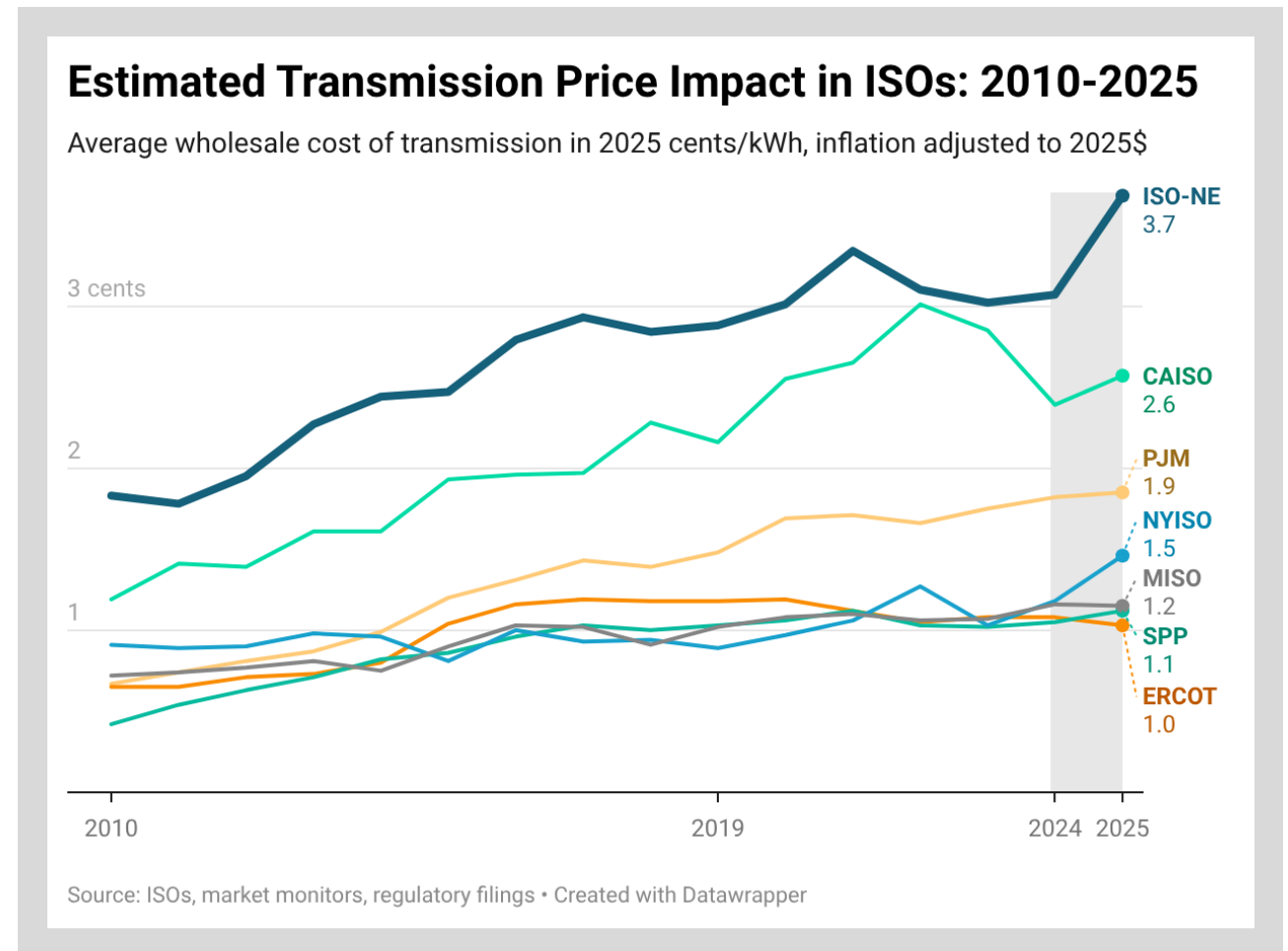


Data are rough estimates based on annually reported distribution O&M and depreciation combined with assumed allocations to distribution of taxes, interest, and shareholder net income. Actual customer price impacts will vary based on the vagaries of general rate cases, cost trackers, and other details.

Source: FERC Form 1 • Created with Datawrapper

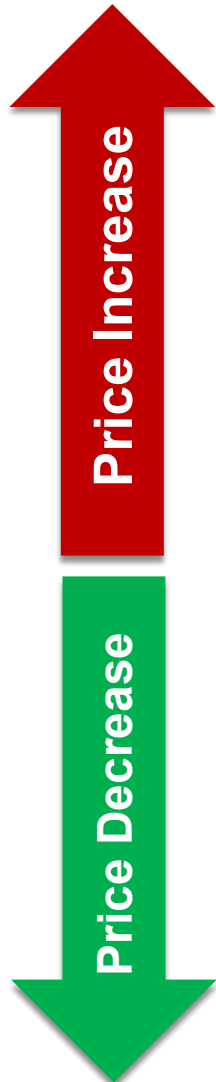
FERC-approved transmission infrastructure costs in New England increased in 2025, pushing retail prices higher (*as did a change in ancillary services*)

- ❑ Many New England states saw retail price increases in 2025: ME (2.5 ¢/kWh), RI (0.9), MA (0.9), CT (0.5)
- ❑ One key reason is that transmission infrastructure costs substantially increased, up **0.6 ¢/kWh on average**
- ❑ Costs in ISO-NE increased in recent years due to reliability needs, aging infrastructure, and inflation; the increase in 2025 was also due to under-collection of previous costs
- ❑ Costs also increased in some other regions, but less so than ISO-NE
- ❑ *Note: ISO-NE made changes to its day-ahead **ancillary services** market in March 2025, via “Forecast Energy Requirement” credits. According to the [market monitor](#), this resulted in additional costs of ~0.5 ¢/kWh in 2025.*



Note: ISO-NE data shown in figure are dominated by trends in regional network service (transmission OpEx and CapEx paid for by all customers in ISO-NE, given the shared nature of the assets) but also include estimates of local network service (smaller lines, the OpEx and CapEx of which vary by utility).

Some additional states experienced notable or interesting retail price changes—for a diversity of previously stated and additional reasons



Maine	Transmission: Significant YoY increase in regional transmission costs
	Storm cost recovery: Increase in cost recovery from storm damage in 2024
	Net billing: Growth in community solar with attractive net billing compensation
	Natural gas: Increased wholesale power prices in 2025 due largely to rise in gas prices
Tennessee	New generation: Investments needed due to significant load growth
	Nuclear outage: Prolonged outage led to more expensive natural gas
	Distribution: Distribution system repairs and inflation in equipment costs
Nevada	Natural gas: High-cost gas from previous years began rolling off bills
Hawaii	Fuel oil: Updated supply contracts reflecting lower global oil prices
N. Carolina	Natural gas: Reduction in fuel surcharges after annual review
	Nuclear tax credits: New federal credits for existing nuclear lowered prices

Medium-term relationships – *2019 to 2025*

Differences in average retail prices and changes to those prices over time can be impacted by many general and some state-specific factors

Mix of sources of supply: gas, coal, oil, nuclear, hydropower, wind, solar, storage, etc.

Local natural resource quality and delivery (pipeline, transmission) constraints

Relative cost of building new infrastructure given labor costs and other regional dynamics

Characteristics of customer load: quantity, growth, load factor, flexibility, etc.

Balance of supply and demand: is the market tight or oversupplied

Age of existing assets and relative need for replacement

Investments in grid modernization: technology and resilience

Impact of natural disasters, extreme weather, wildfires

Policy & planning: RPS, EE, DER, low-income assistance, cap-and-trade, nuclear, etc.

Health and environmental regulations that impact plant retirement and costs

Utility ownership structure: public- vs. investor- owned

Presence and design of wholesale competitive market

Presence and nature of retail electricity competition

Degree of vertical integration (generation ownership) among utilities

Service territory size, geography, population, and other characteristics

This Section Focuses More Holistically on Relationships from 2019 to 2025

The slides that follow focus on a subset of factors that may have influenced state-level price changes since 2019. This section emphasizes 2019-2025 to span COVID and the period in which nominal prices spiked. The analysis does not assess all possible factors but includes many of the most-likely candidates. Factors include those listed in the previous YoY section (here focused on 2019-2025 data) and additional ones that influenced longer-term trends:

- Distribution and transmission costs, as impacted by age-based replacement, hardening, expansion, supply-chain constraints, storm cost recovery, and wildfire mitigation
- State renewables portfolio standards, net energy metering, and carbon cap-and-trade programs
- Generation and fuels, including utility-scale wind and solar (outside of state requirements), natural gas, coal, and nuclear
- Organized capacity markets and related prices
- Utility ownership, financing, and other differences

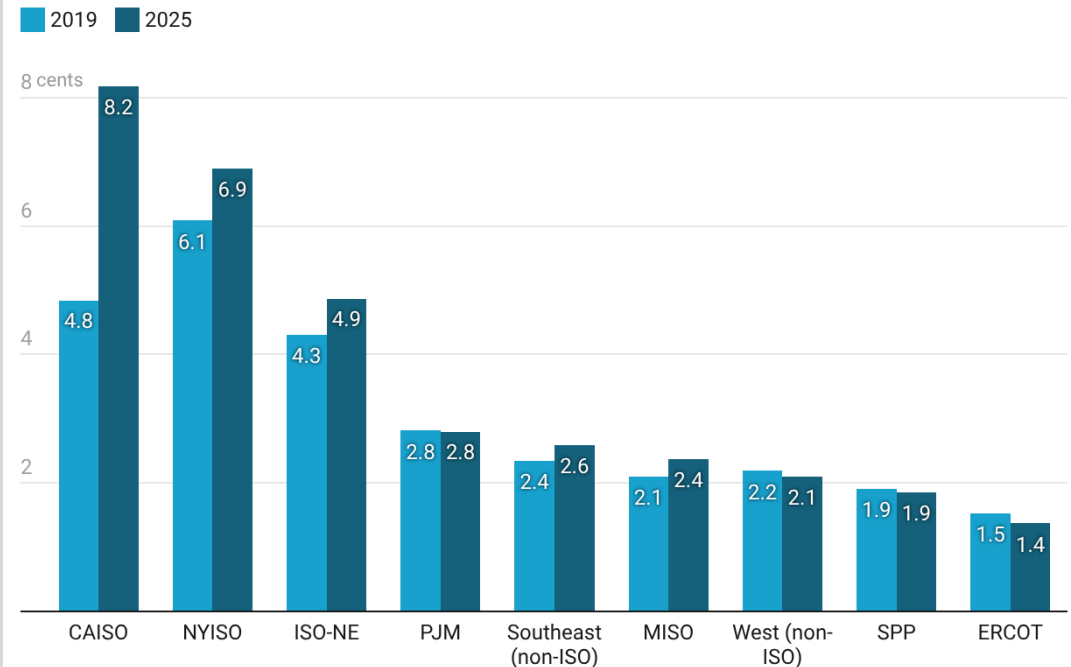
Load growth is separately covered in the following section

Distribution expenditures contributed to IOU retail price increases from 2019 to 2025, especially in California, New York, and New England

- Total IOU distribution spending grew at an avg. 5%/year from 2019 to 2025 (in real\$), increasing retail prices in some regions
- The impact of distribution costs on prices is difficult to estimate consistently; figure estimates average price impact from 2019 to 2025 across all customers (*note: actual impacts will be greater for smaller customers who, in practice, bear most of these costs*)
- Average price impacts span a wide range: **highest distribution-related prices and price increases in CAISO, NYISO, ISO-NE**
 - ▣ CAISO prices impacted by wildfire mitigation
 - ▣ All three regions impacted by reductions in retail sales, magnifying impact of cost increases on prices
- Estimated distribution price impacts are lower and changed less in all other regions

Estimated Distribution Price Impacts: 2019 to 2025

Rough estimate of average price impact of distribution in cents/kWh, inflation adjusted to 2025\$

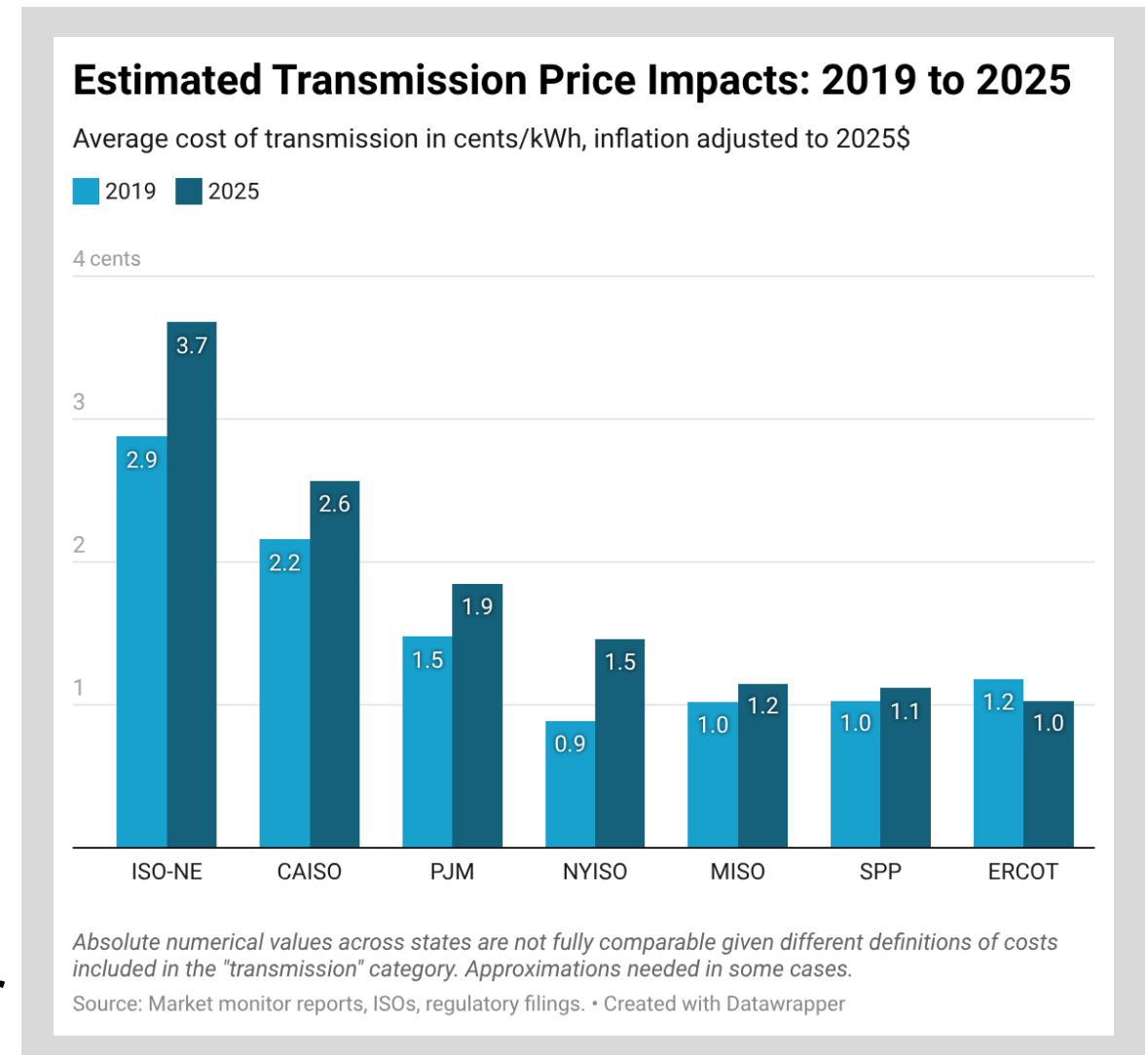


Data are rough estimates based on annually reported distribution O&M and depreciation combined with assumed allocations to distribution of taxes, interest, and shareholder net income. Actual customer price impacts will vary based on the vagaries of general rate cases, cost trackers, and other details. To approximate price impacts, we assume a 1-year lag between cost incidence and prices, and further adjust lag assumptions based on tax policy changes in late 2017 and PG&E's bankruptcy in 2019. As a result, 2025 estimates are based on recorded costs in 2024, while 2019 estimates are based on average costs from 2017-2018 for all regions except CAISO, which uses 2017 cost data to approximate 2019 prices.

Source: FERC Form 1 • Created with Datawrapper

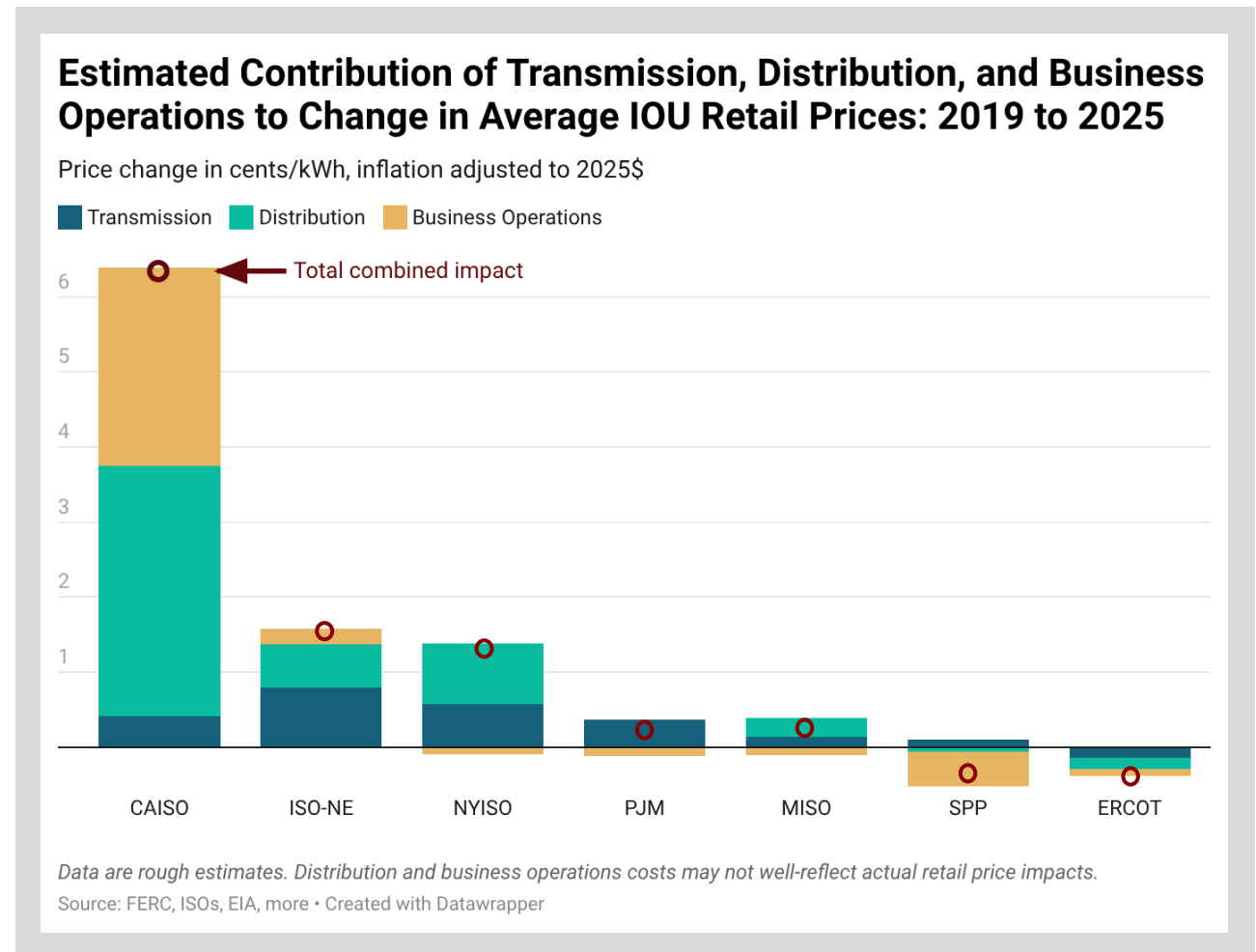
Transmission expenditures contributed to retail electricity price increases from 2019 to 2025, especially in New England, New York, California & PJM

- Transmission costs are highest & increased the most in **ISO-NE**, up **0.8 ¢/kWh from 2019 to 2025 after adjusting for inflation**
 - ▣ Driven primarily by reliability needs, replacement of aging infrastructure, and higher equipment costs
- Costs also increased significantly in NYISO (0.6 ¢/kWh), and CAISO & PJM (0.4 ¢/kWh)
 - ▣ Same drivers, but also variously impacted by policy desire to connect new renewable sources
- Transmission costs are generally lower and changed less in ERCOT, MISO, and SPP
- Transmission costs reported here include ISO-planned investments as well as those planned by local utilities with little ISO role; see earlier slide for data back to 2010
- Note: **higher transmission costs can lower retail prices if** used to reduce supply costs



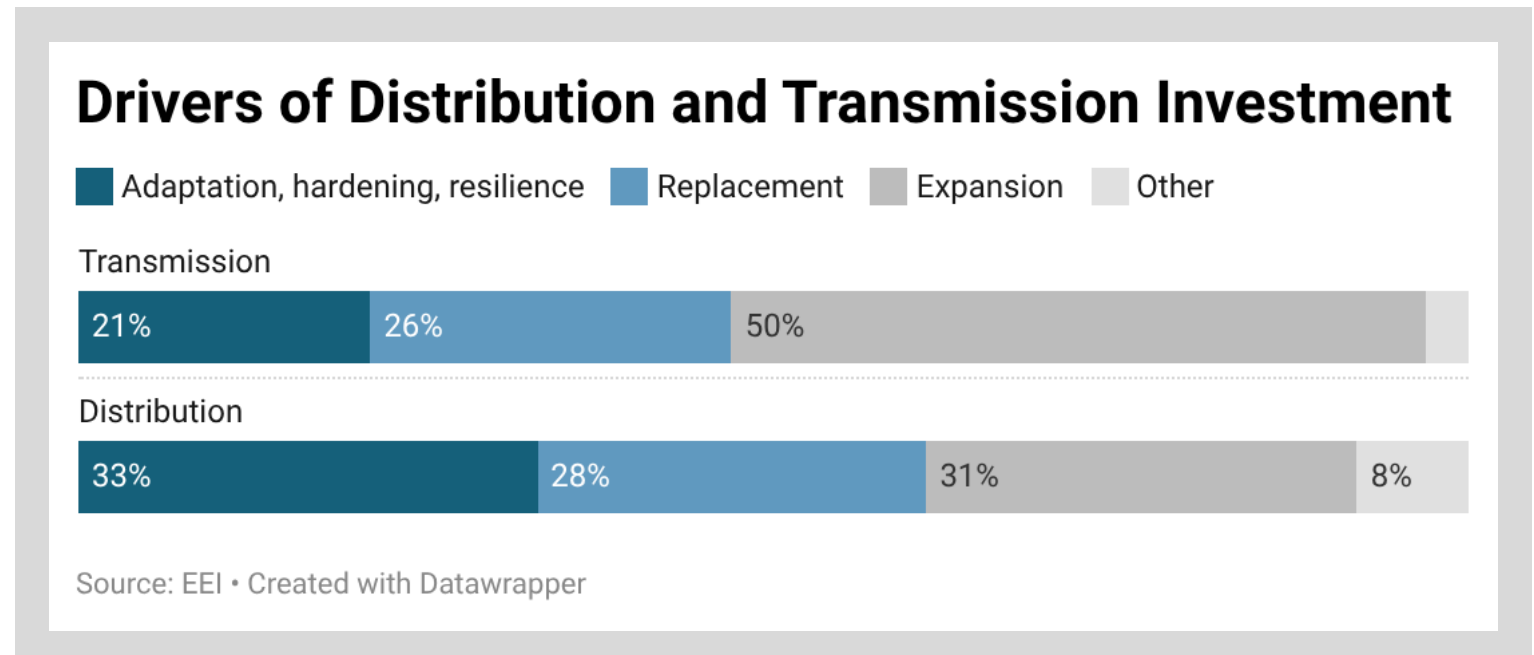
Transmission, distribution, and business operations costs helped drive inflation-adjusted price increases in regions with the largest rise in prices

- The figure shows estimates of the combined role of transmission, distribution, and business operations in increasing average inflation-adjusted IOU prices from 2019 to 2025 in ISO regions
 - Business operations costs come from FERC Form 1, and include expenses related to: customer accounts; customer service and informational; sales; administrative and general
 - Distribution and business operations estimates should be considered rough approximations, given the complexities of estimating retail price impacts from FERC Form 1 cost data
- Despite limitations, combined impact of these three drivers was especially significant in CAISO, ISO-NE, NYISO
- Wildfire costs in CA are included in the distribution (e.g., vegetation management) & business operations (e.g., liability insurance) categories



Recent distribution and transmission investments have been driven by replacement and hardening, though with growing emphasis on expansion

- Grid infrastructure is aging—T&D assets were often built more than 50 years ago and, over time, need to be replaced and modernized
 - Example: Brattle estimates >\$10 billion/year annually for replacement of aging transmission assets¹
- **EI companies** reported in 2025 that **61% of distribution & 47% of transmission** investment was driven by “**replacement**” or “**adaptation, hardening, and resilience**” initiatives²
- “**Expansion**” was **50% of transmission** investment in the 2025 survey, up from 42% in the 2024 survey²
- Relying on a different data source and method, FERC reports 31% of transmission line-miles built in 2025 were designed for reliability needs, 28% for aging infrastructure, and 18% for load growth³



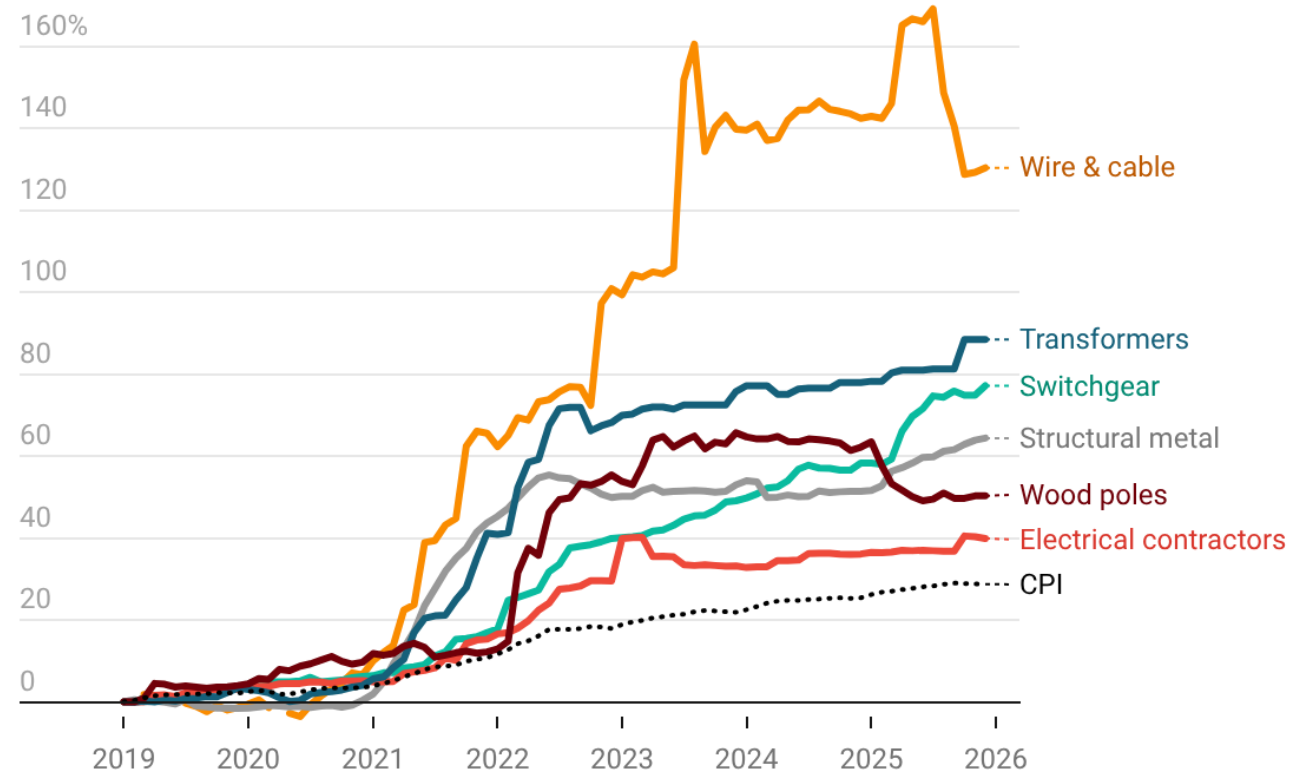
¹ [Brattle \(2025\)](#), ² [EEI \(2025\)](#), ³ [FERC \(2026\)](#)

One of the reasons for growth in distribution and transmission costs is that equipment prices have grown well-above the pace of inflation

- Regardless of the driver, supply-chain constraints and the resulting elevated equipment prices have contributed to the overall impacts of T&D in increasing retail prices
- The figure shows producer price indices for various equipment and services important to T&D, contrasting those price increases with the economy-wide CPI
- Price indices for some T&D equipment have moderated somewhat in recent years, but price increases since 2019 remain well above the CPI in most cases

Producer Price Index for T&D Equipment and Services

Shown as percentage change relative to January 1, 2019, also compared to CPI



Source: FRED, BLS • Created with Datawrapper

Storm recovery and wildfire mitigation also impacted distribution (and transmission) costs, significantly increasing retail prices in some states

Storms result in **reactive** investments: needed repairs following damage; **>1 ¢/kWh** impact for some East & Gulf coast states

Recent Estimates of Utility Storm Recovery Price Impacts

Utility	State	Year	Duration	Price Impact (¢/kWh)
Duke Energy Florida	FL	2025	1-year	3.2
Central Maine Power	ME	2025	2-years	2.5
Tampa Electric Company	FL	2025	1.5-years	2.0
Entergy Louisiana	LA	2025	15-years	1.4
Florida Power & Light	FL	2025	1-year	1.2
Central Florida Electric Coop.	FL	2025	temporary	0.9
NYSEG	NY	2025	6-12 years	0.9
SWEPSCO	LA	2025	14-years	0.7
Eversource	CT	proposed	15-years	0.6
Duke Energy Progress	SC	2025	20-years	0.6
CLECO	LA	2022	9-20 years	0.5
Oncor	TX	proposed	long-term	0.5
Georgia Power	GA	proposed	4-years	0.4
National Grid	MA	2025	5-years	0.4
Duke Energy Progress	NC	2025	20-years	0.4
Green Mountain Power	VT	2025	1-year	0.4
Centerpoint	TX	2025	15-years	0.3
Entergy Texas	TX	2022	15-years	0.2
Rochester Gas & Electric	NY	2025	10-years	0.2
Duke Energy Carolinas	NC	2025	20-years	0.2
PPL Electric	PA	2025	1-year	0.2
PSE&G	NJ	2025	long-term	0.2
AEP Texas	TX	2019	5-15 years	0.1
Portland General Electric	OR	2023	7-years	0.1

Source: LBNL • Created with Datawrapper

Includes estimates for a subset of utilities. Estimates represent actual or likely impact on (mostly) residential prices in year shown. Some cost recovery mechanisms are short duration whereas in other cases costs are securitized and price impacts will persist for as many as 20+ years. Data are imperfect and should only be used to illustrate wide range of and significant impacts.

Sources: Review of regulatory filings and tariffs, for subset of utilities

Wildfires (& storms) motivate **proactive** action to reduce damage; **> 4 ¢/kWh** price impact in CA, growing throughout West

Recent Estimates of Utility Wildfire Mitigation Costs

Utility	State	Equivalent Impact (¢/kWh)	Scope
PG&E	CA	5.0	actual price: mitigation & liability
SDG&E	CA	4.7	actual price: mitigation & liability
SCE	CA	3.3	actual price: mitigation & liability
KIUC	HI	1.7	proposed cost: mitigation
Hawaii Electric	HI	1.5	proposed cost: mitigation
PSCo	CO	1.5	estimated price: mitigation
Rocky Mountain Power	UT	0.7	proposed cost: mitigation
PGE	OR	0.6	actual price: mitigation
Rocky Mountain Power	WY	0.6	actual price: mitigation & liability
Idaho Power	ID	0.4	proposed cost: mitigation
Pacific Power	OR	0.4	actual price: mitigation
Northwestern	MT	0.4	estimated price: mitigation
APS	AZ	0.3	actual cost: mitigation
Nevada Power-North	NV	0.3	actual price: mitigation
AEP Texas	TX	0.3	actual cost: mitigation
Avista	WA	0.2	actual price: mitigation
Oncor	TX	0.2	actual cost: mitigation
PNM	NM	0.1	actual price: mitigation & liability
PSE	WA	0.1	actual price: mitigation & liability
SPS	TX	0.1	actual cost: mitigation
Nevada Power-South	NV	0.0	actual price: mitigation

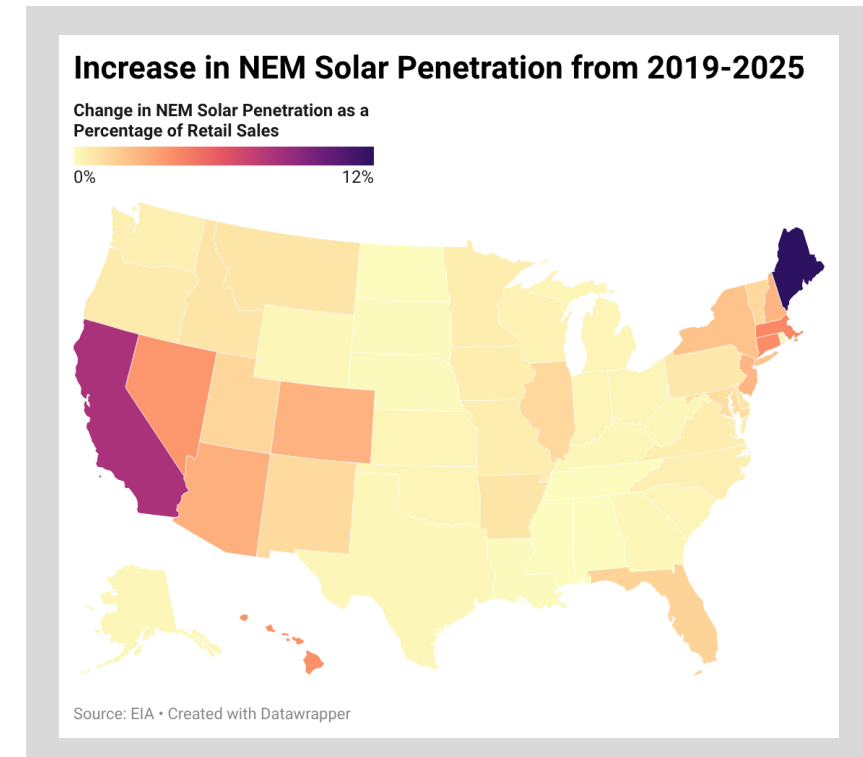
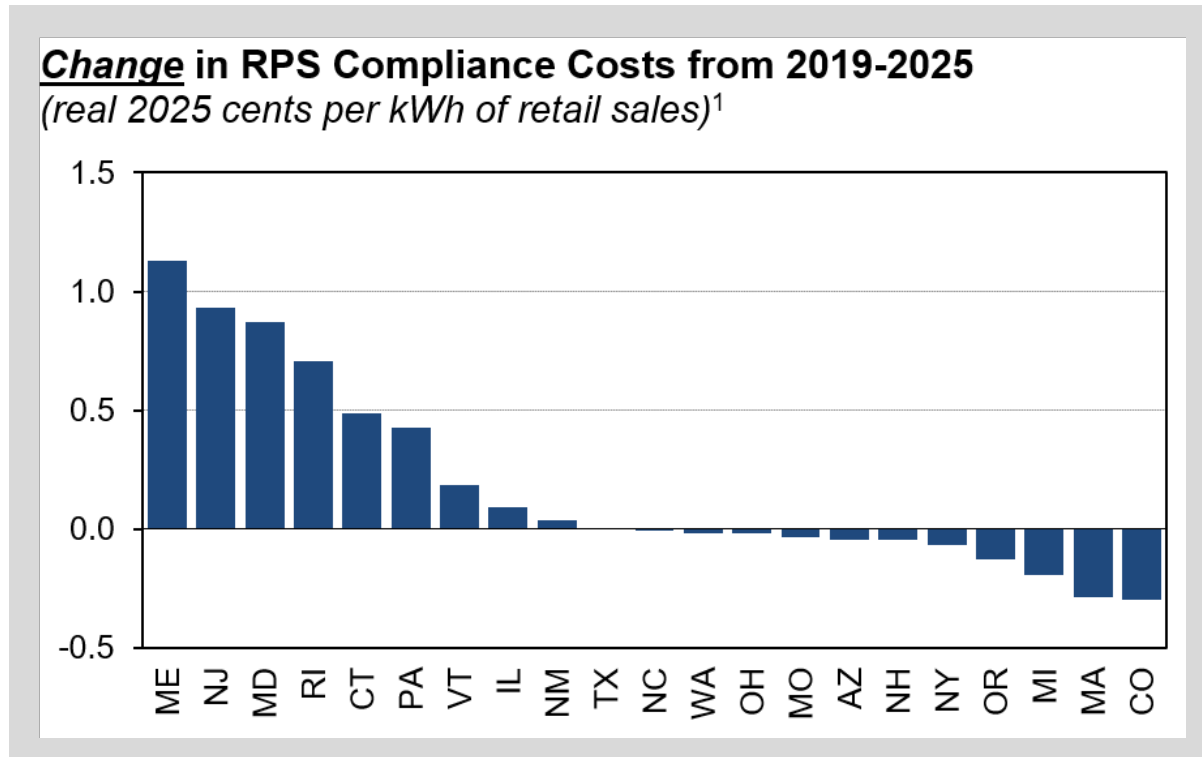
Source: LBNL • Created with Datawrapper

Includes recent (2025) or projected (2026-2028) estimates for subset of utilities, some actual and some proposed. Data are not fully comparable: sometimes includes price impacts, other times total costs normalized by sales. Most only cover mitigation costs, but some also include liability insurance. Data should only be used to illustrate wide range of and significant impacts.

Sources: Review of regulatory filings and tariffs, for subset of utilities

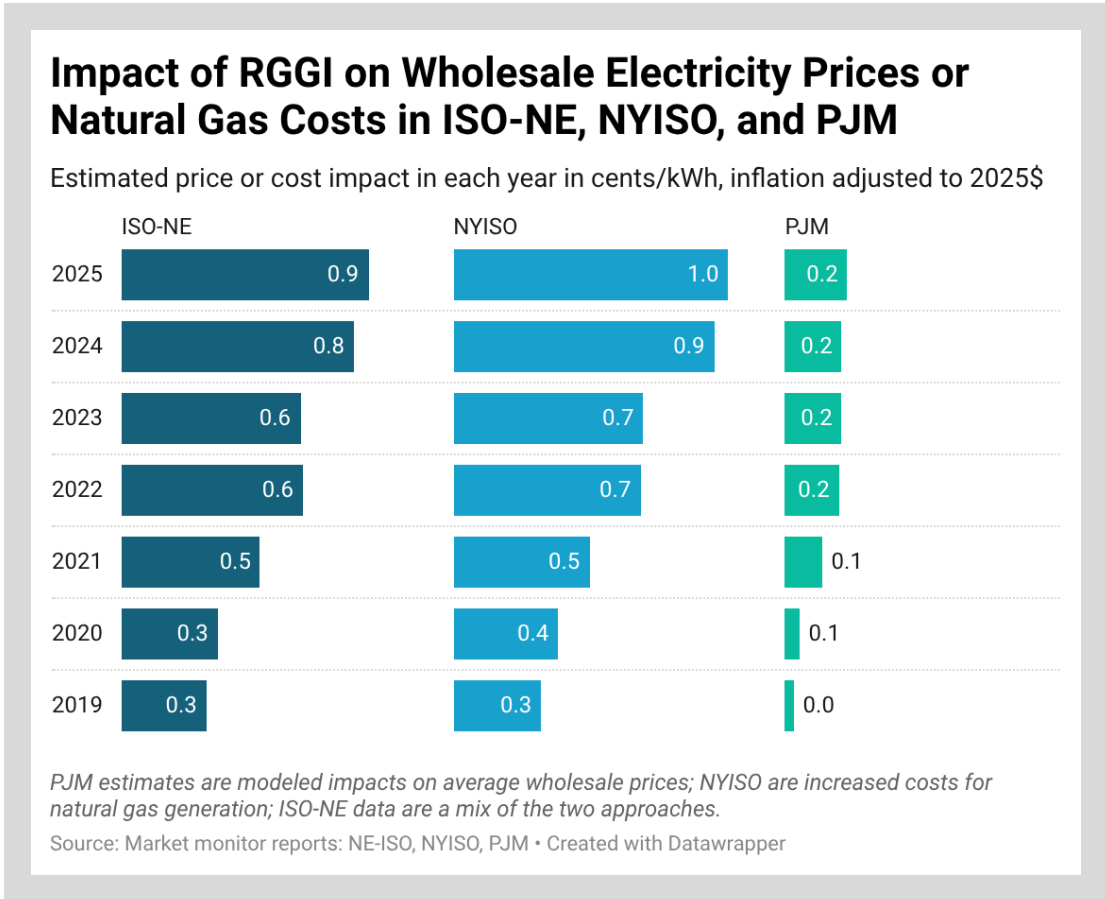
State policies to require or encourage wind and solar deployment above what the competitive market would deliver have often increased prices

- ▣ **RPS:** Recent wind and solar growth that contributed to incremental state RPS demand often increased prices
- ▣ RPS compliance costs from 2019 to 2025 equate to an average price increase of ~ 0.2 ¢/kWh; in several mid-Atlantic and New England states ~ 1 ¢/kWh¹; earlier statistical analysis supports impacts of this magnitude
- ▣ **Net metering:** Benefits adopters, but can result in fixed costs being spread over lower sales, leading to higher prices²
- ▣ Effects variable; statistical analysis and other studies suggest impacts < 0.5 ¢/kWh in ~ 40 states, but as high as > 2 ¢/kWh in CA



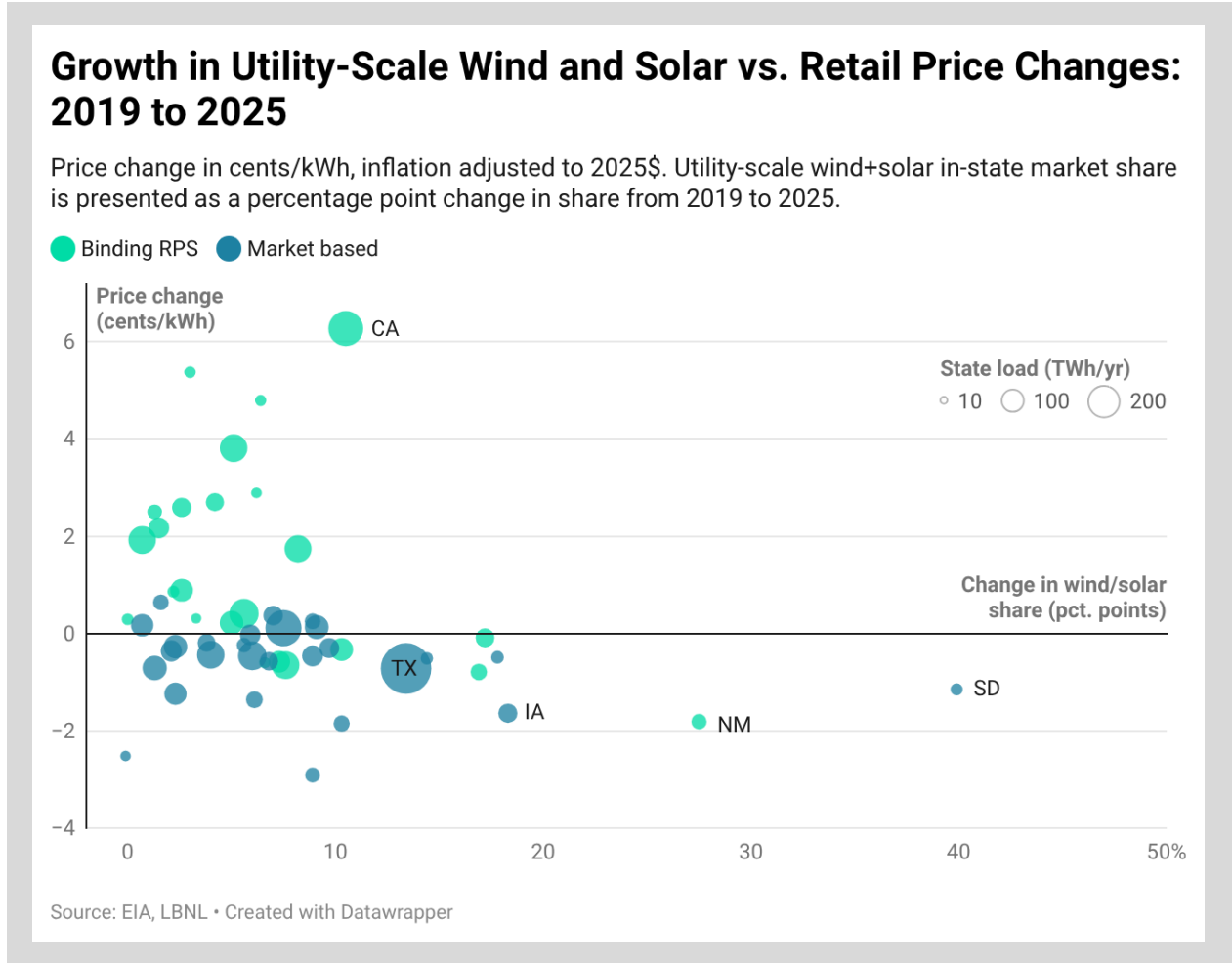
Carbon cap-and-trade programs have increased retail prices in some states, though recycling of auction revenue reduces customer impacts

- Carbon prices in the Regional Greenhouse Gas Initiative (RGGI) have risen since 2019, increasing wholesale prices from 2019 to 2025 by **> 0.5 ¢/kWh** in New England & New York
- Impacts on average retail prices are hard to estimate, but will generally be lower than wholesale impacts for two primary reasons:
 - Generation is not all purchased in the wholesale market or from carbon-producing generators
 - Auction revenue is, in part, re-invested in customer efficiency and bill discounts, reducing bill impacts
- California and Washington have similar programs, with even-higher absolute allowance prices:
 - CA: Change in allowance prices from 2019 to 2025 increased natural gas costs from ~ 0.9 to 1.3 ¢/kWh
 - WA: Change in allowance prices from 2019 to 2025 increased natural gas costs from ~ 0 to 2.5 ¢/kWh
 - Customer bill credits and large amounts of low-emitting resources moderate impacts in both states, but there is evidence of recent price impacts in Washington; in CA, residential bill credits appear to have offset price impact



State policies often increased prices but “market based” wind and solar, supported by tax incentives, do not appear to have driven price increases

- States with binding RPS’s often experienced increased prices, as shown on earlier slide and as illustrated in the figure to the right
- Most growth in utility-scale wind and solar occurred outside of RPS policies, supported by tax incentives but not compelled by RPS programs (termed “market based” here)
- There is no obvious correlation between higher price increases and “market based” deployment of wind and solar over this period
- Earlier statistical analysis supports these graphical relationships: binding RPS generally increased prices, especially in many New England and Mid-Atlantic states; “market based” wind and solar do not appear to have increased prices in recent years

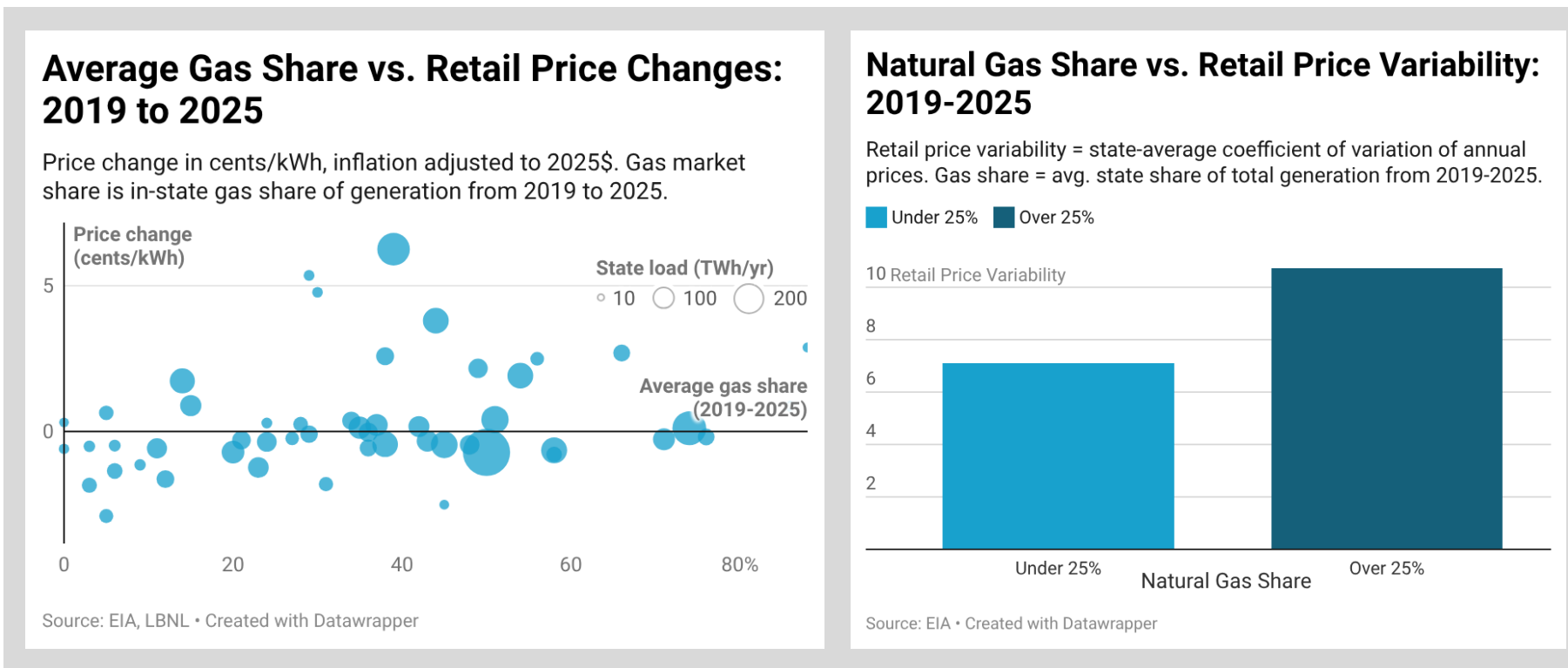


Simple bubble graphic should be interpreted with care (here and on next slides) because price changes were driven by multiple factors and due to correlated effects; earlier statistical analysis was used to isolate drivers, and produced results consistent with general observed trends

Low-cost natural gas reduced retail prices over the long term; gas price fluctuations impacted year-to-year variation in retail prices over 2019-2025

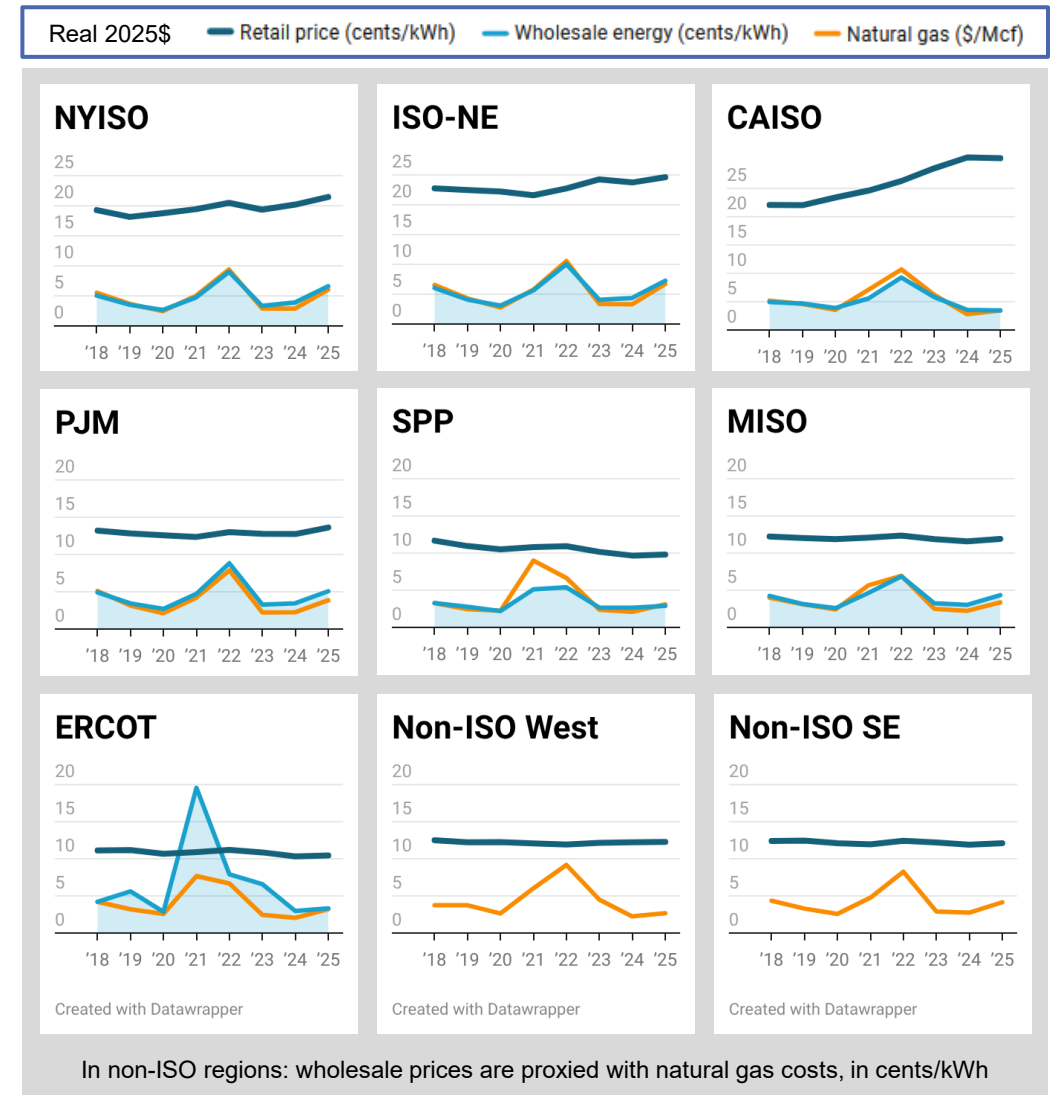
- Declining inflation-adjusted natural gas prices contributed to reductions in generation costs over the long term, putting downward pressure on wholesale (and retail) electricity prices—as shown on earlier slide
- Nationally, inflation-adjusted gas prices were slightly higher in 2025 than 2019, though gas’ share of state generation doesn’t have a strong relationship with retail price changes over that period (*left figure*)

- However, year-to-year retail price variability from 2019-2025 was impacted by a state’s average natural gas share, illustrating the impact of natural gas price volatility on retail electricity prices (*right figure*)



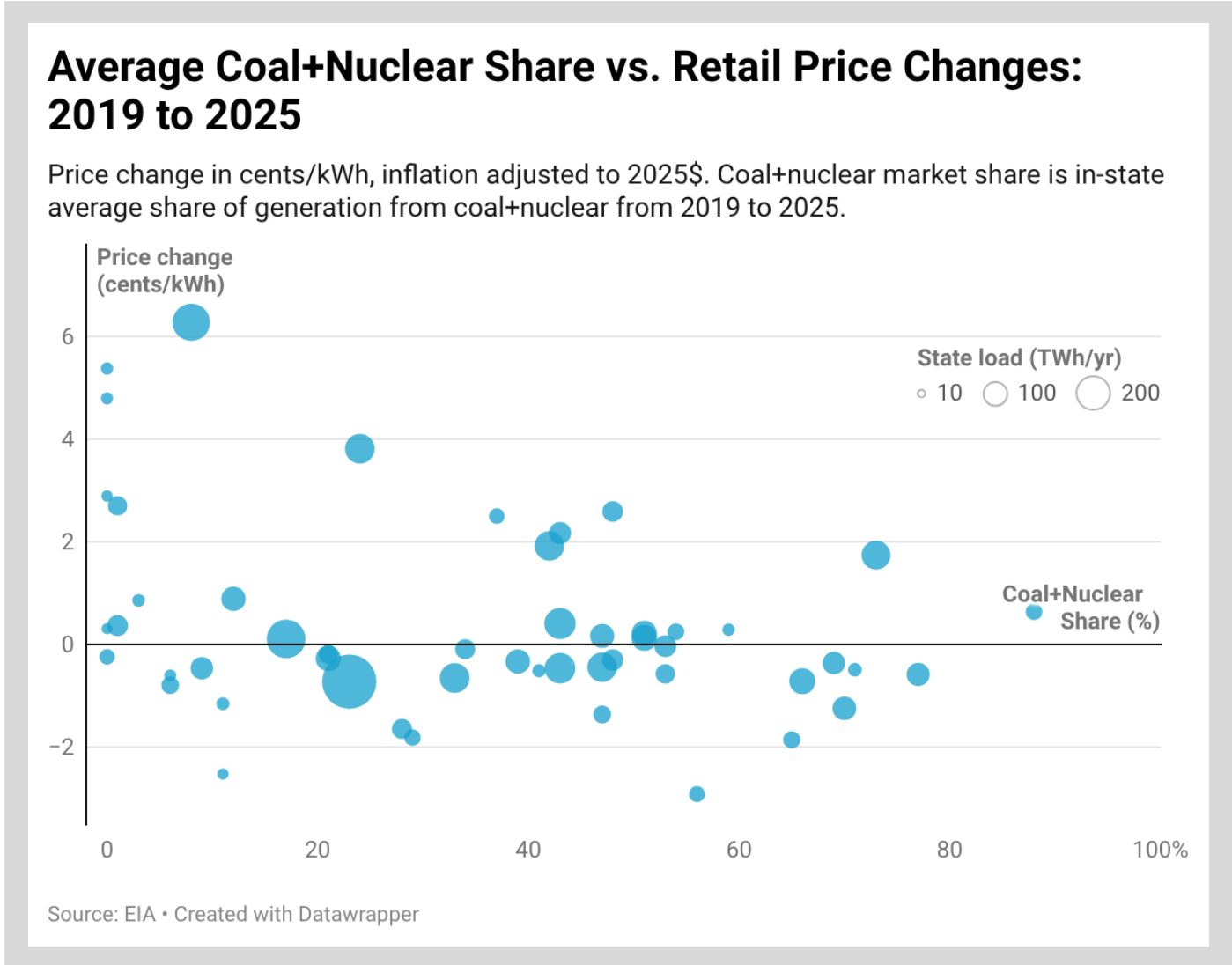
Gas price fluctuations impacted year-to-year variation in retail electricity prices over 2019-2025, with some regions more exposed than others

- The impact of natural gas prices on retail electricity prices depends not only on price levels but on the degree and speed by which fuel costs and wholesale prices pass through to retail electricity prices
- Acknowledging that passthrough amounts and lags vary by region and supplier, the figure depicts natural gas and wholesale and retail electricity prices by region
- In some regions, retail electricity prices appear more-exposed to short-term gas and wholesale prices fluctuations (e.g., NYISO, ISO-NE), sometimes with lag
- Between 2019 and 2025, natural gas prices were impacted by the shock of the Ukraine-Russia war, creating an increase and subsequent decrease in retail electricity prices in many regions
 - Some individual states experienced increased retail prices of 2 ¢/kWh or even > 4 ¢/kWh through 2022-2023
- Gas prices also generally increased in 2025 relative to 2024, as described previously, impacting retail prices



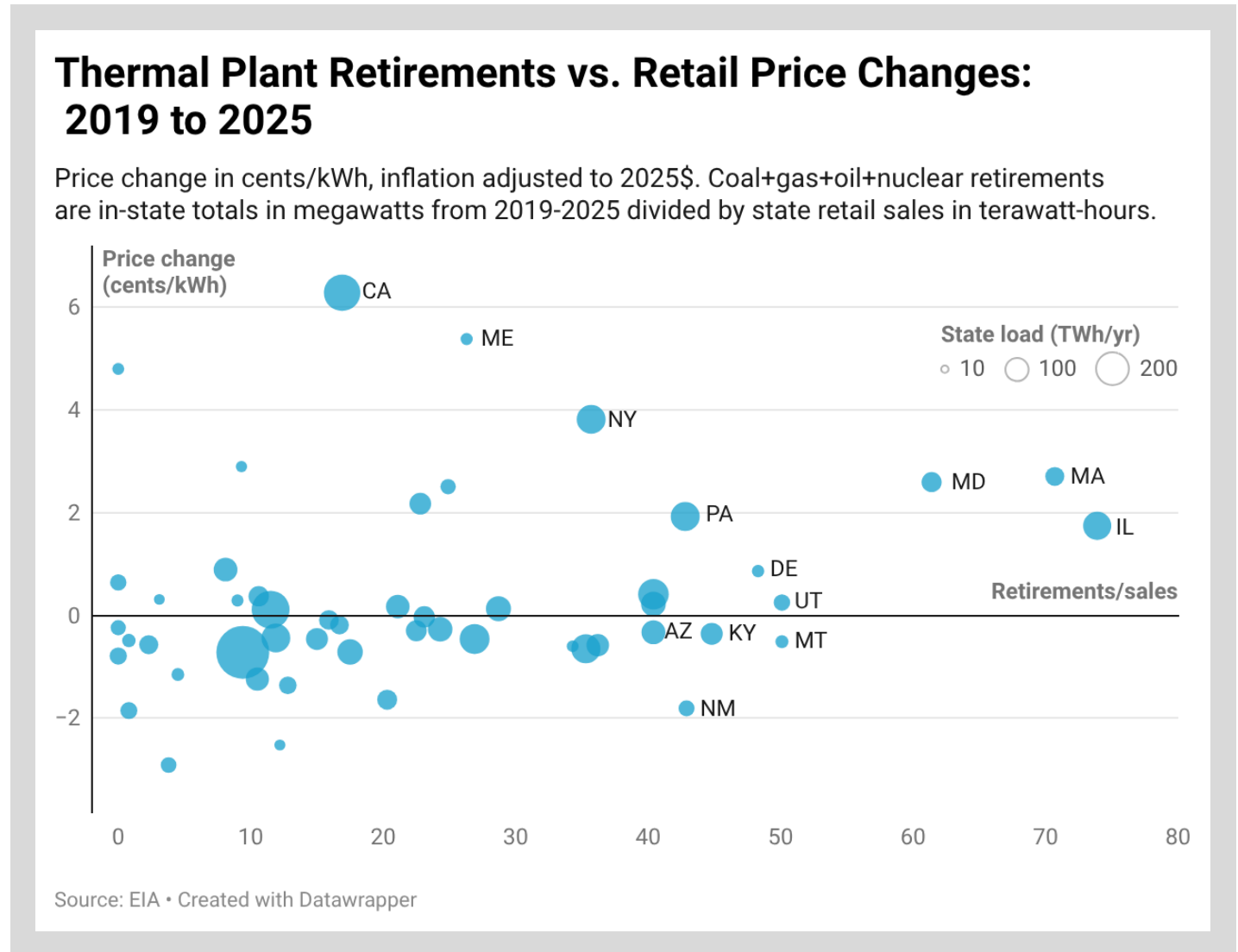
Greater shares of coal and nuclear may have placed downward pressure on prices from 2019 to 2025, but correlations are weak

- Figure shows the relationship between a state’s average coal + nuclear generation share from 2019 to 2025 and the contemporaneous change in retail electricity prices
- Visually suggests that greater coal + nuclear shares may have placed downward pressure on retail prices
- Exploratory statistical analysis also suggests that higher shares of coal+nuclear *may* be associated with declining inflation-adjusted retail prices over this period, but the results are not statistically significant
- Additional analysis would be necessary to accurately assess historical relationships between generation sources and retail prices



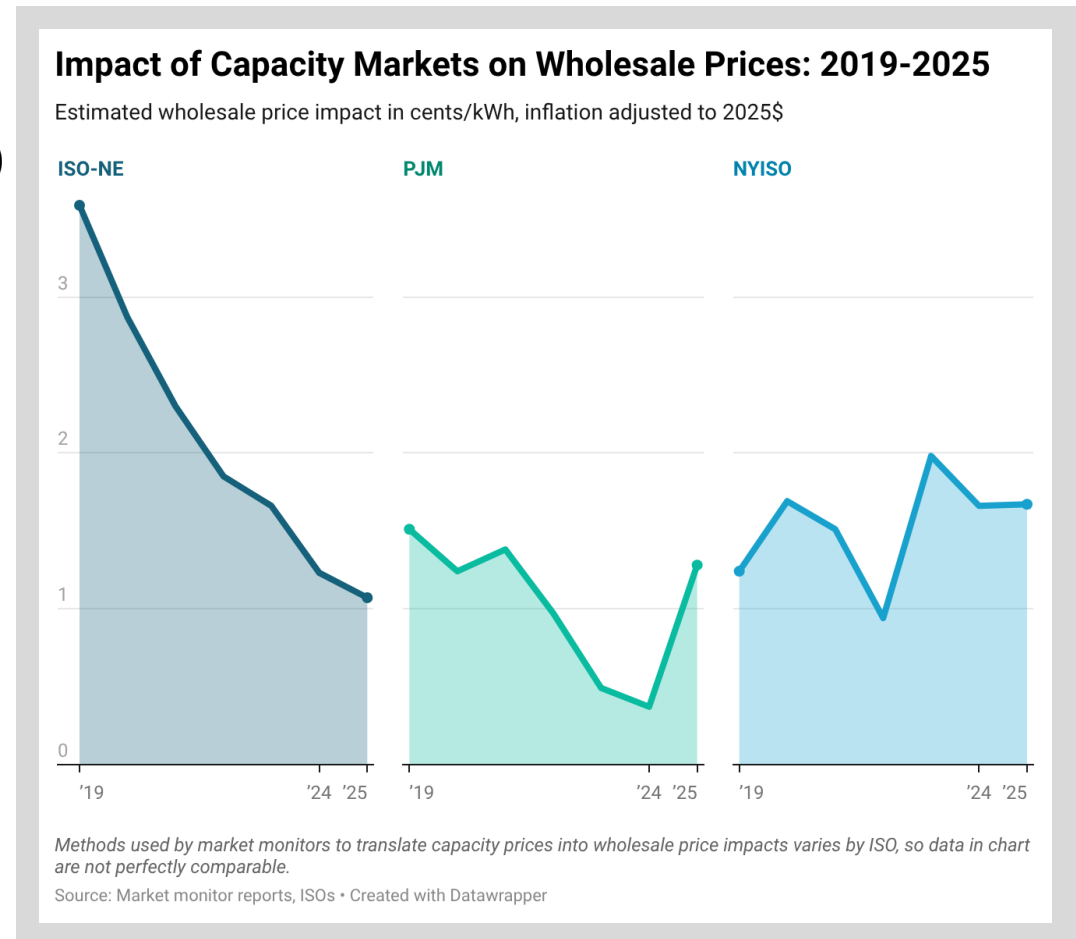
The relationship between state-level thermal-plant retirements from 2019 to 2025 and change in retail prices is unclear, and may change in the future

- Figure shows the relationship between a state’s total thermal (coal+gas+oil+nuclear) retirements from 2019 to 2025 (in MW, normalized by retail sales in TWh) and the contemporaneous change in retail electricity prices
- It is hard to discern a clear relationship from the simple figure; detailed statistical analysis or case studies would be necessary to accurately assess the historical relationships
- However, historical relationships may not be relevant going forward, given accelerating actual and prospective load growth



Capacity markets had varied impacts on wholesale (and therefore retail) electricity prices over the 2019 to 2025 period

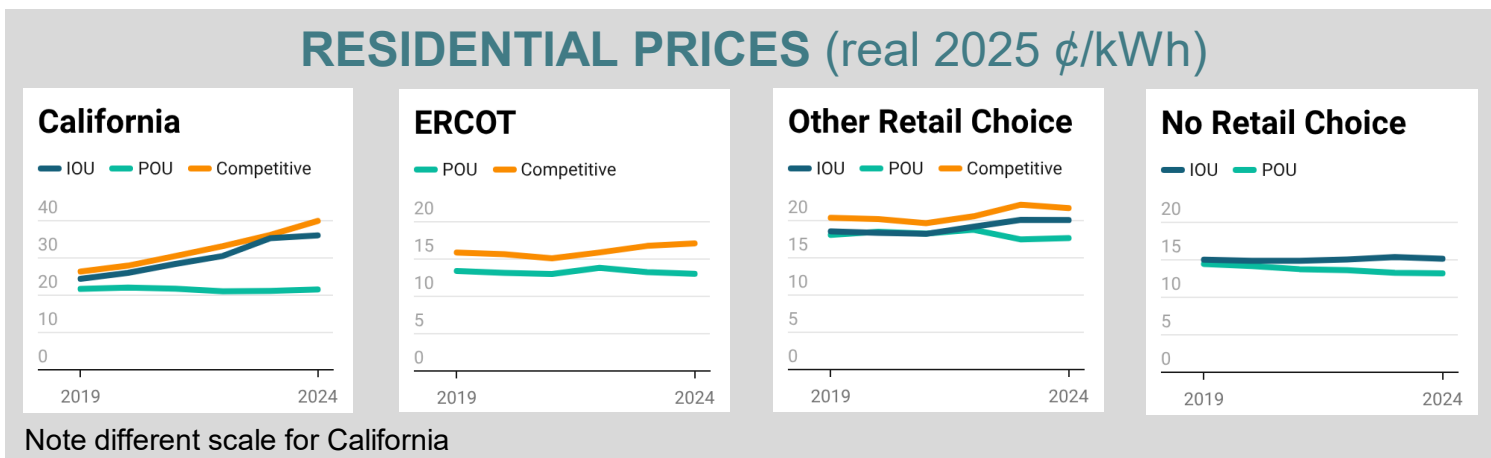
- 3 ISOs have organized capacity markets that cover sizable fractions of capacity needs; figure shows the impact of capacity markets and costs on region-wide average wholesale prices
- Capacity market in **PJM** increased avg. wholesale prices by **0.9 ¢/kWh** from 2024 to 2025, with a further **+0.6 ¢/kWh** impact expected in 2026 (see earlier slide)
- Impacts in PJM are not entirely unique as shown by NYISO & ISO-NE, but note that “regional averages” obscure larger (or smaller) impacts as some states / suppliers have capacity hedges or self-provide
- Capacity price impacts in ISO-NE declined sharply since 2019, placing downward pressure on retail prices; in NYISO, impacts were variable but grew
- Not depicted, but relevant to retail electricity prices (*though translation of below prices to retail is not 1-for-1*):
 - MISO: capacity price auction cleared at \$6.5/kW-mo for 2025-26, compared to \$0.1/kW-mo for 2019-20
 - CAISO: bilateral capacity prices rose to >\$10/kW-mo since 2023 (higher than PJM), vs. \$3.5/kW-mo in 2019



Note: Capacity market results were impacted by the balance between supply and demand along with many regional revisions to market design

The impact of growth in IOU capital expenditure on financing costs may be a *partial* contributor to price differences vs. publicly owned utilities

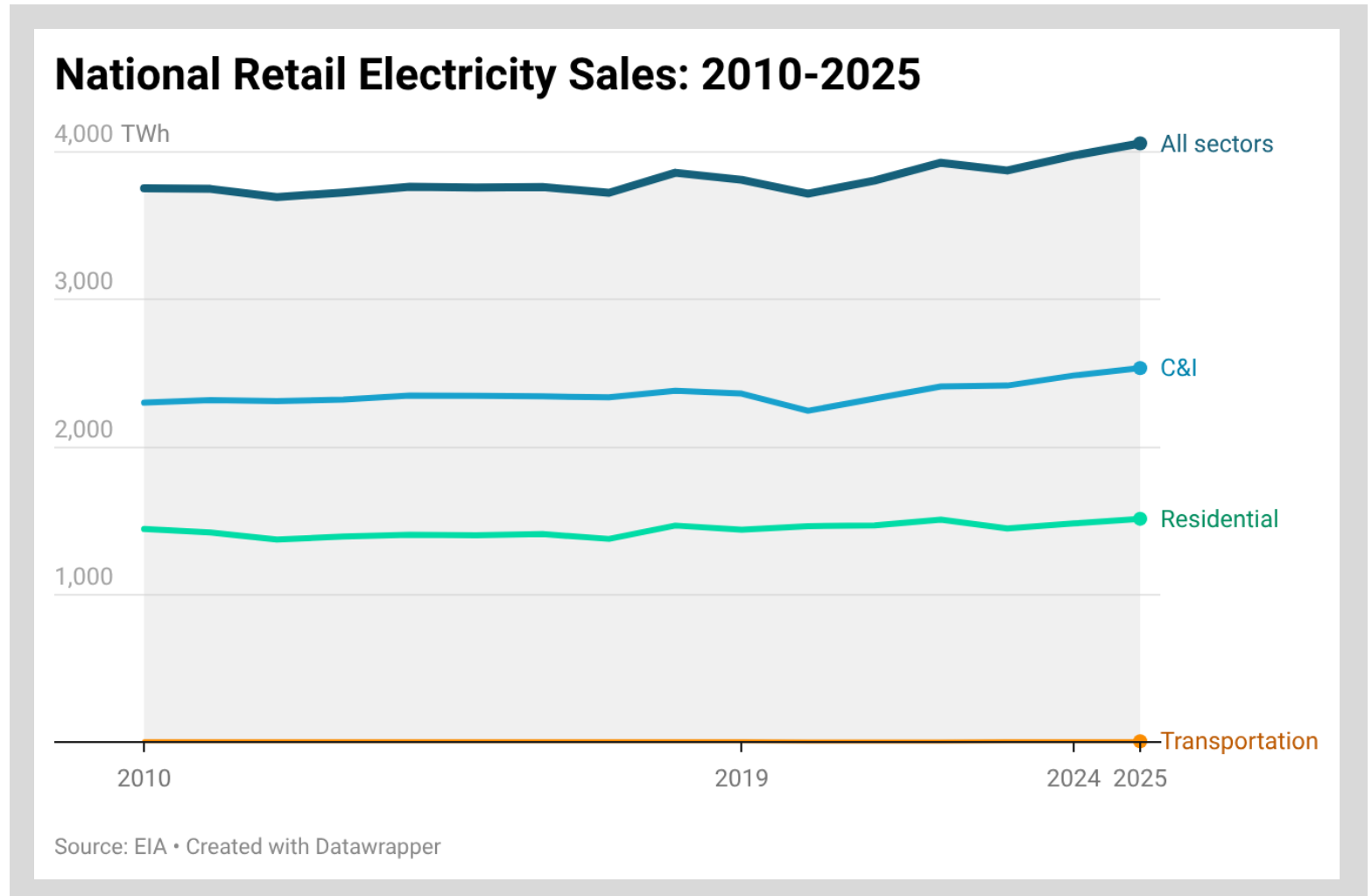
- Based on FERC Form 1, growth in total IOU CapEx resulted in an increase in the aggregate rate base, from **\$1.11 trillion in 2019** to **\$1.25 trillion in 2024** in real 2025\$; rate base growth increases prices via depreciation and through debt interest payments & shareholder earnings
- Nationally, impact of **interest & earnings** on prices was **~0.3 ¢/kWh** from 2019-2025 (real\$)
 - Larger increases: CA (~1.1 ¢/kWh), Southeast (~0.8 ¢/kWh), NY (~0.6 ¢/kWh)
- This may explain a **portion** of the **growing gap** between IOU and publicly-owned utility (POU) prices—but only a minority
 - Growth in IOU vs. POU price differences vary regionally but are generally increasing; other factors must be at play, e.g. (1) different exposure to wildfire risk & storms, (2) POU access to low-cost debt & federal hydro, (3) different taxes, (4) state policies targeting IOUs; (5) differences in service territories



Deep Dive – *Accelerated load growth*

After a long period of slow growth, national electricity demand has begun a more-rapid rise—driven largely by commercial and industrial customers

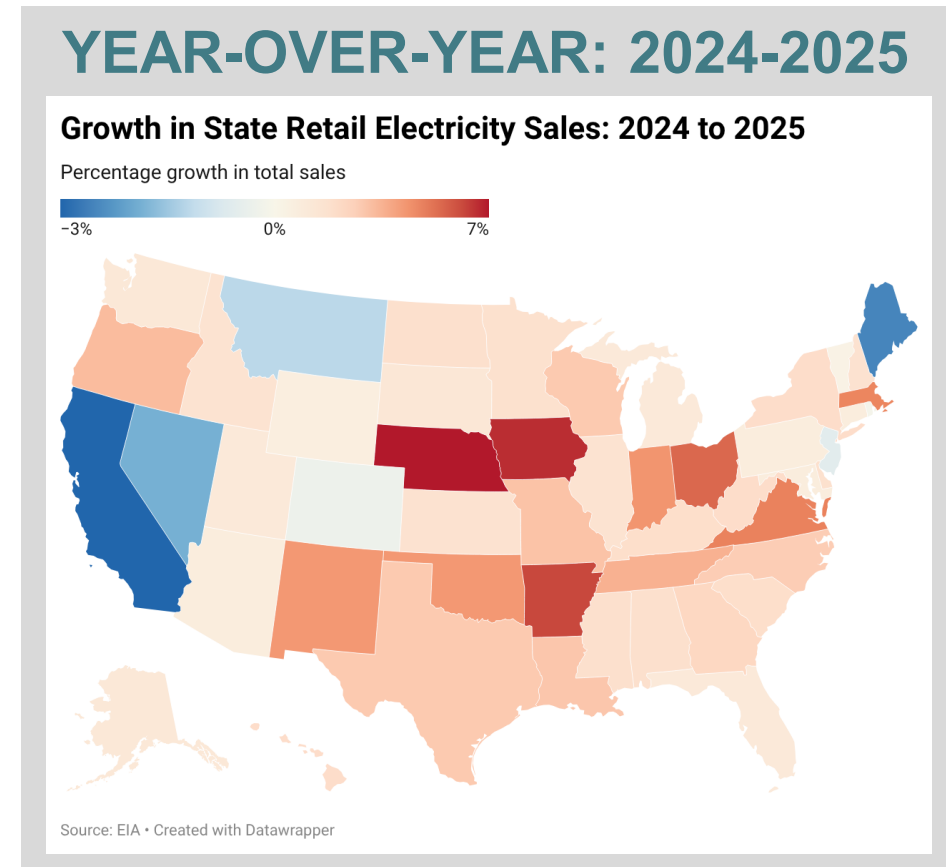
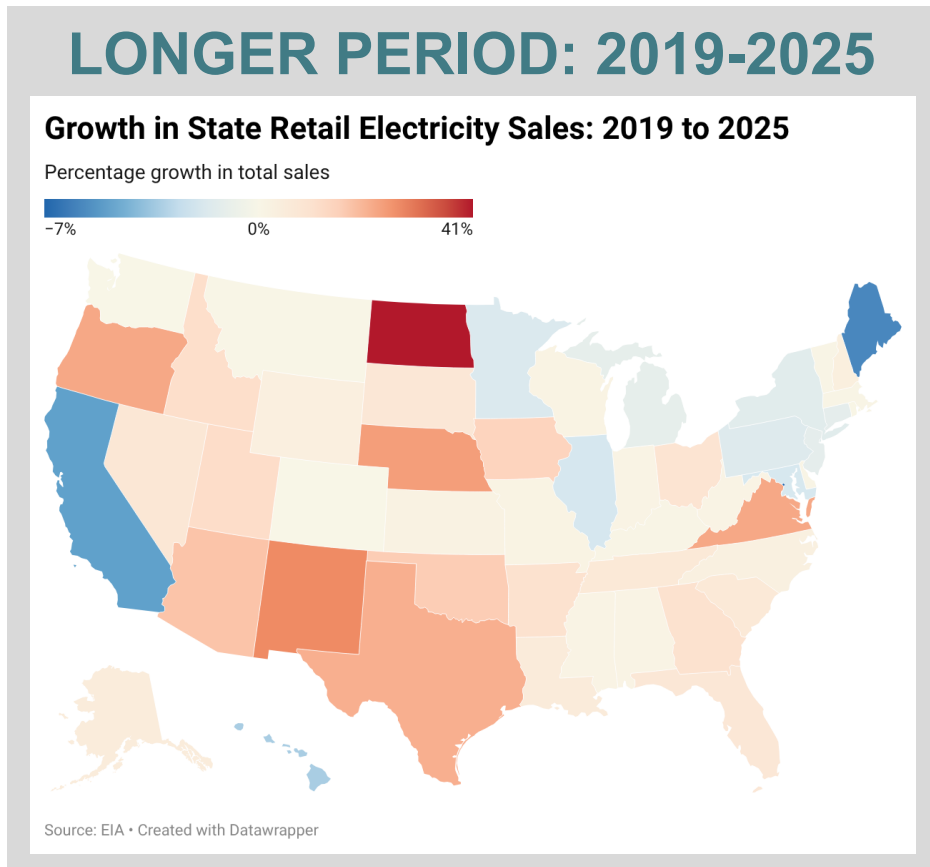
- Figure shows retail sales¹ to end-use customers
- Compound annual growth rate (CAGR) has increased:
 - 2010-2019: 0.2%/yr
 - 2019-2025 = 1.1%/yr
- Year-over-year growth from 2024-2025 = 2.1% (*following 2.6% from 2023-2024*)
- C&I = larger share of recent growth, e.g., 2019-2025:
 - TWh growth: 70% C&I, 30% residential
 - CAGRs: 1.2% C&I, 0.8% residential



¹ Retail sales represent electricity sales to end use customers via the grid and so exclude any electricity demand that is met through customer-sited resources

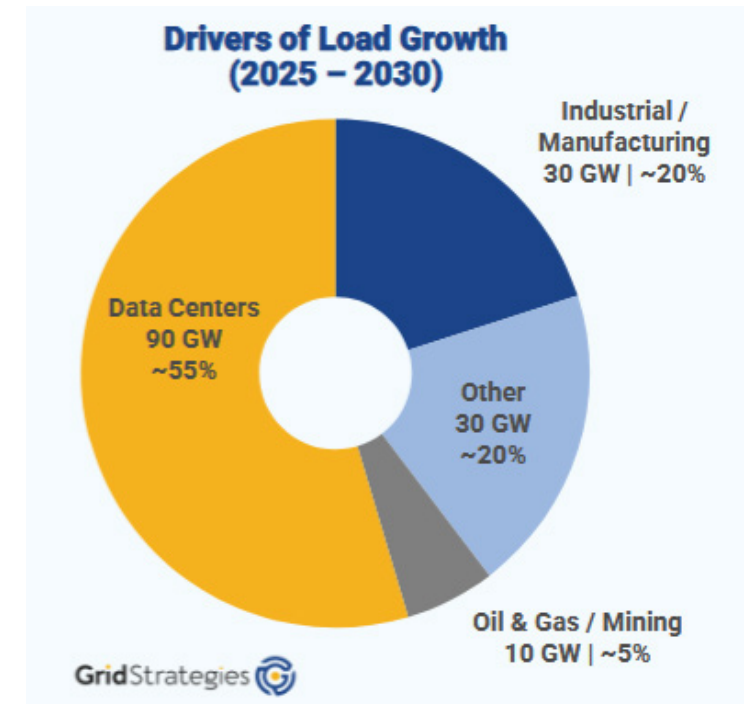
Recent growth is uneven across states, with some seeing a decline in retail sales, others an increase: since 2019 (*left*) and 2024 (*right*)

- 2019-2025: highest in North Dakota, New Mexico, Nebraska, Virginia, Oregon, Texas
- 2024-2025: highest in Nebraska, Iowa, Arkansas, Ohio, Virginia, Massachusetts
- Declining retail sales in some states is due in part to behind-the-meter solar



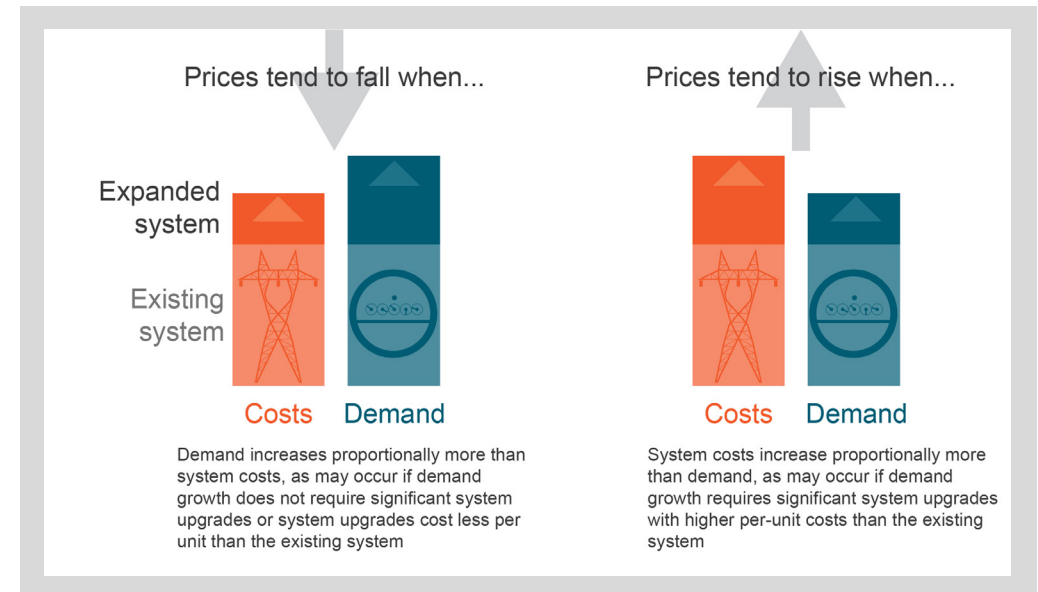
Significant additional load growth is anticipated, but with substantial uncertainty on amount (*which may, in part, depend on price trajectories*)

- Example: Grid Strategies¹ compiled data on load growth projections through 2030, submitted by utilities to FERC:
 - ▣ 5.7%/year forecasted growth in electricity use, 2025-2030
 - ▣ 3.7%/year forecasted growth in peak demand, 2025-2030
 - ▣ Higher growth in use vs. peak implies a growing load factor compared to current and past values
- FERC submissions show data centers as largest driver:
 - ▣ Grid Strategies notes that the 90 GW from data centers may be overstated by 25 GW, but remains dominant
 - ▣ More generally, Grid Strategies highlights both significant recent increases in growth expectations and the significant uncertainty
- NERC reports a potential 224 GW growth in summer peak demand over the next 10 years²
- Focusing solely on data centers, in late 2024, LBNL estimated:³
 - ▣ Data centers consumed about 4.4% of total U.S. electricity in 2023
 - ▣ Uncertain growth: could consume between 6.7% and 12% of total U.S. electricity by 2028



Load growth can increase or decrease retail prices: depends on ability to optimize existing assets, cost of new supply & delivery, tariff structures

- Electricity service entails a large share of **fixed costs** "sunk" in **grid infrastructure**. All else equal, average (per-unit) costs and thus retail prices tend to go down when these costs are spread over more sales.
- Demand growth may, therefore, at least in the long term, lower prices. However, the growth projected over the next decade is substantial, and there are conditions under which growth will increase prices.
 - Case studies in later slides illustrate both possibilities
- Three additional factors affect how load impacts prices:



1. System utilization
 All grids can absorb demand growth, to a degree, by utilizing "spare" capacity in existing assets. The degree to which new demand can optimize the use of existing assets—such as through load flexibility or simply via a high load factor—is a key determinant of the impacts of demand growth on prices.

2. System costs
 Demand growth will impose new variable costs and investments in grid infrastructure. The impact on overall average costs and therefore prices depends on the relative size of these new "marginal" costs versus the average cost of the existing electricity system.

3. Cost allocation & recovery
 Retail electricity prices emerge from the allocation of system costs to specific customers. Cost allocation practices will determine how cost increases or savings are allocated to different customers and will therefore determine the net impacts of demand growth on customer-specific prices.

- **Market structure** (vertical integration vs. restructured) can also influence relationships, as it can impact how marginal costs impact retail prices in the near term and how costs are allocated among customers

State-level load growth was associated with declining all-sector average retail prices in recent decades, including from 2019 to 2025 in most states

- From 2019 to 2025, states with the highest growth generally saw average retail prices decline in real terms
 - **Over 1 ¢/kWh reduction in all-sector average prices in highest-growth states, based on earlier statistical analysis**
- Those states where load declined often experienced price increases
- Cost growth significantly driven by T&D investments—with prevailing rate structures, greater load can lead to fixed costs being spread over more demand, reducing per unit costs (*though impact is bi-directional, as price reductions should also increase load*)
- Note: Commercial sector saw most load growth; had largest price reductions

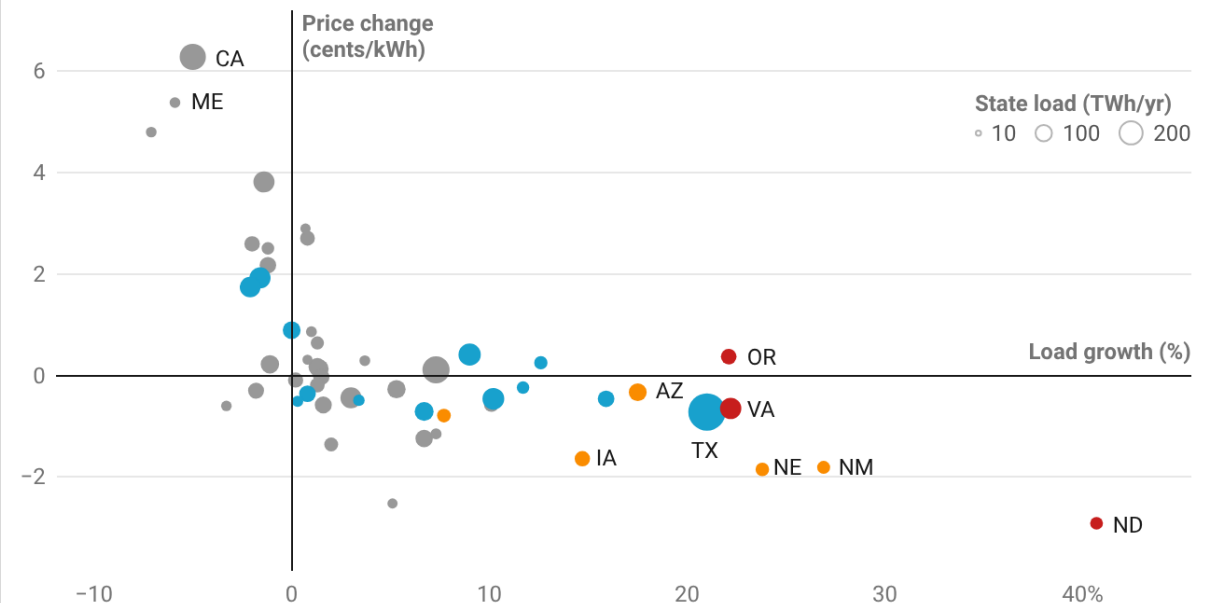
ALL-SECTOR AVG. PRICES VS. TOTAL GROWTH

Load Growth vs. Retail Price Changes: 2019 to 2025

Price change in cents/kWh, inflation adjusted to 2025\$. Load growth is percent change in retail sales.

Data center & cryptocurrency growth relative to state load in 2019

● Low Growth ● Medium Growth ● High Growth ● Very High Growth



Data center and cryptocurrency growth defined as increase in MWs from 2019-2024, relative to 2019 state load. Very high = > 45 MW/MWh; High = > 15 MW/MWh; Medium = > 5 MW/MWh

Source: EIA, S&P Global · Created with Datawrapper

Note: Presence of significant data center load does not appear to alter conclusions 51

Residential customers may have benefited from load growth from 2019 to 2025 in some states, but the relationship is less clear and may change

- Figure depicts relationship between total state-level load growth and average residential prices from 2019 to 2025
- The relationship between residential prices and load growth is not as clear as for all-sector average prices
 - To some degree, as expected: if growth was mostly C&I, then *typical* cost allocation practices should not shift costs or benefits to households
 - Residential customers in some states appear to have benefitted, or at least not been injured, from state-level load growth
- States with contracting load were often those with higher price increases
- The presence of significant data center and cryptocurrency growth does not appear to alter these conclusions
- Past need not be prelude, illustrated by the PJM example on a later slide

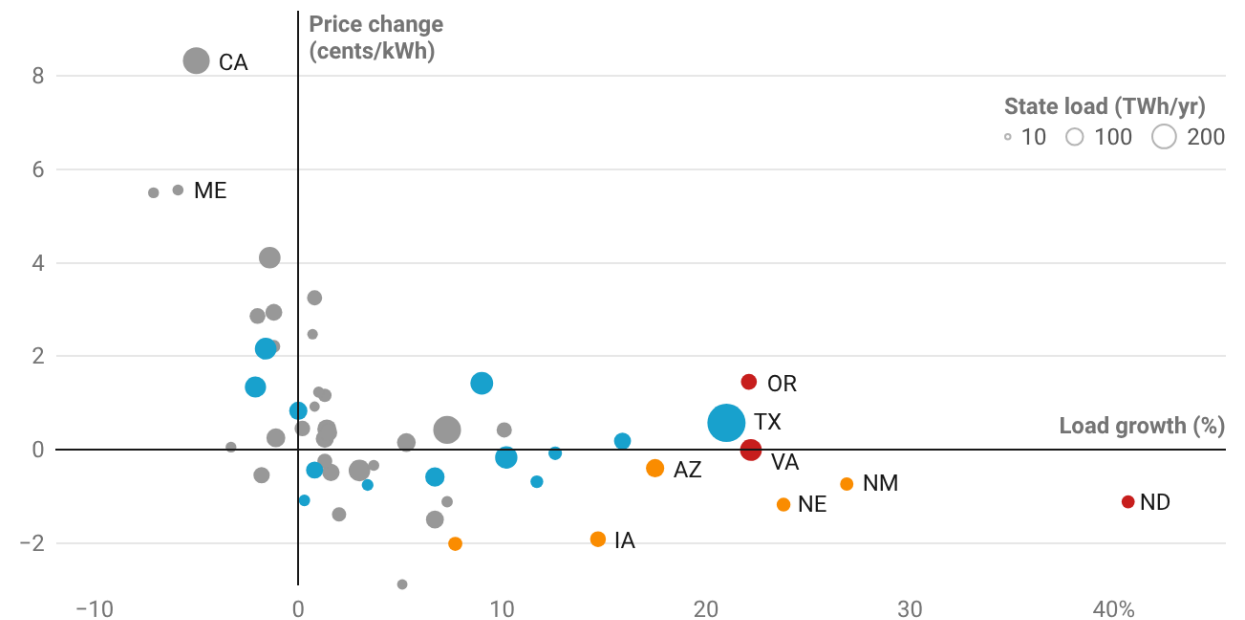
RESIDENTIAL PRICES VS. TOTAL GROWTH

Load Growth vs. Residential Price Change: 2019 to 2025

Price change in cents/kWh, inflation adjusted to 2025\$. Load growth is percent change in retail sales.

Data center & cryptocurrency growth relative to state load in 2019

● Low Growth ● Medium Growth ● High Growth ● Very High Growth



Data center and cryptocurrency growth defined as increase in MWs from 2019-2024, relative to 2019 state load. Very high = > 45 MW/MWh; High = > 15 MW/MWh; Medium = > 5 MW/MWh.

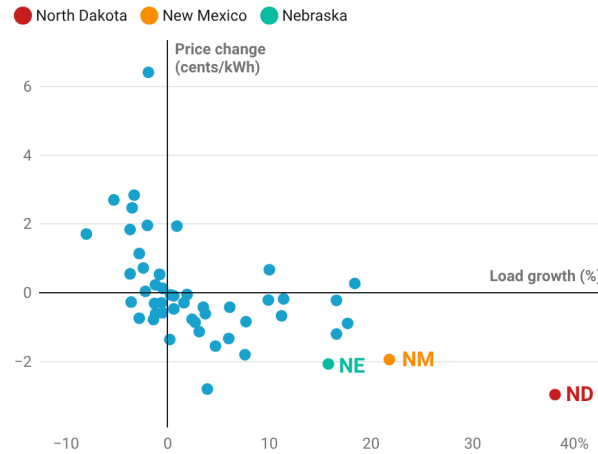
Source: EIA, S&P Global • Created with Datawrapper

Case Study: North Dakota, New Mexico & Nebraska increased load and lowered prices

Managing load growth while reducing inflation-adjusted retail prices (with data through 2024¹)

1 Three states have significantly increased load while reducing inflation-adjusted retail prices

Load Growth vs. Price Change: 2019 to 2024

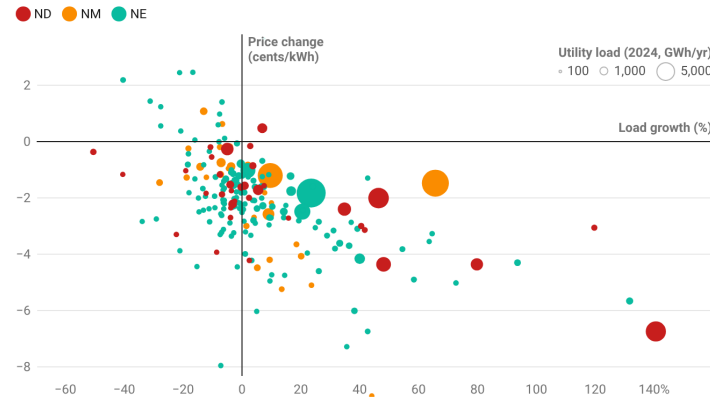


Source: EIA • Created with Datawrapper

2 Utilities with the greatest load growth generally experienced the largest reduction in prices

Impact of Load Growth on Utility-Level Average Retail Price Changes in North Dakota, New Mexico, Nebraska: 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2025\$. Load growth in percentage terms from 2019 to 2024. A few small-utility outliers are excluded due to the y-axis scale.



Source: EIA • Created with Datawrapper

3 Utilities with sizable C&I growth lowered C&I prices; residential customers were not harmed

ND, NM, NE: Impact of Utility- & Sector- Specific Load Growth on Retail Price Changes from 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2025\$.

Utility Grouping	Residential Load Growth	Residential Price Change	C&I Load Growth	C&I Price Change
High Load Growth: >20%	-1%	-1.3	64%	-2.7
Low Load Growth: 0-20%	4%	-1.3	10%	-1.4
Negative Load Growth: <0%	-2%	-0.9	-10%	-0.9

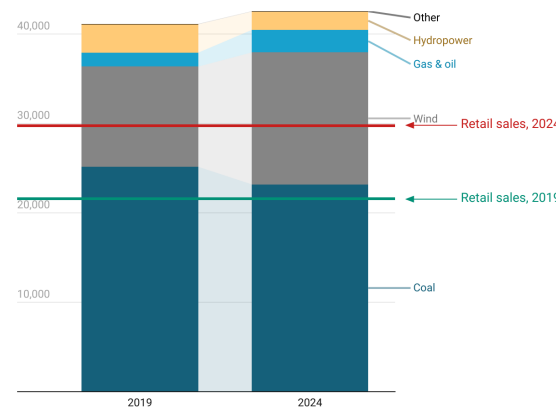
Source: EIA • Created with Datawrapper

4 Load growth matched with abundant, low-cost energy enabled positive outcomes

- Substantial C&I growth enabled fixed costs to be spread over more load
- Abundant, low-cost energy enabled load to be served at low incremental cost

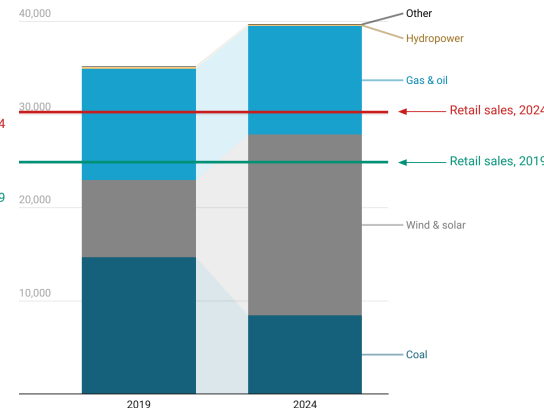
¹ Utility-level EIA data only available through 2024, so slide focuses on 2019-2024

North Dakota Generation and Retail Sales (GWh)



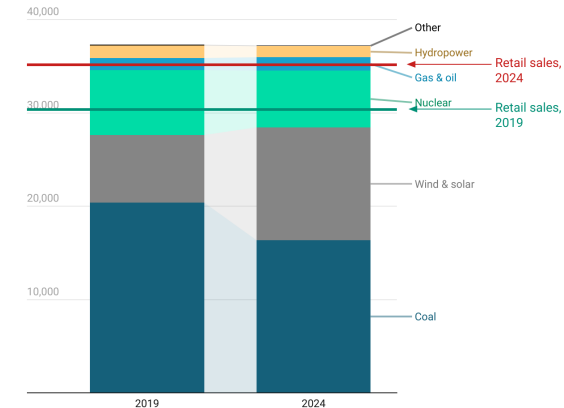
Source: EIA • Created with Datawrapper

New Mexico Generation and Retail Sales (GWh)



Source: EIA • Created with Datawrapper

Nebraska Generation and Retail Sales (GWh)

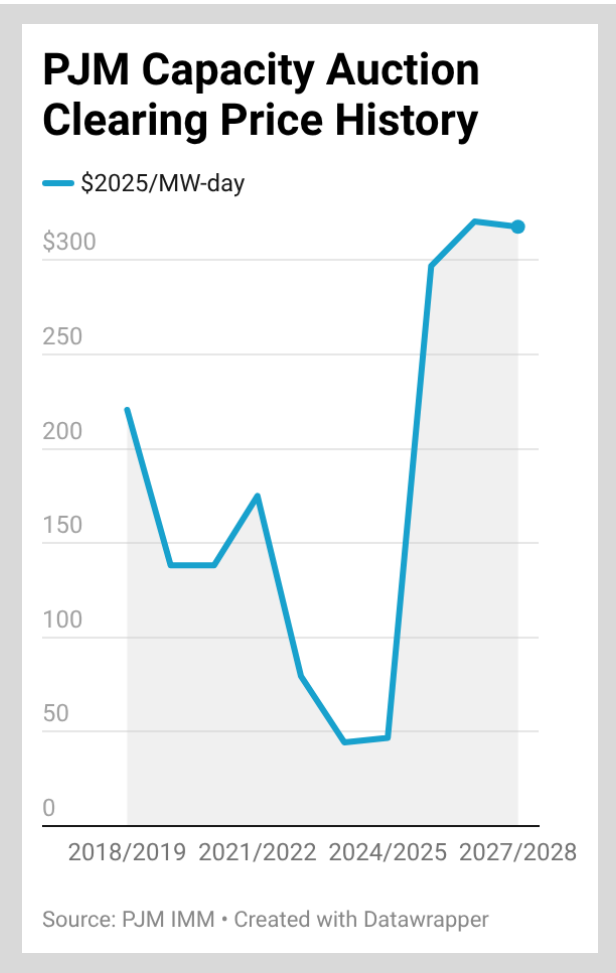


Source: EIA • Created with Datawrapper

Case Study: PJM Capacity Auction demonstrates price increases with load growth

Accelerated load growth combined with supply and delivery constraints leads to significant price increases

1 Significant increase in PJM capacity prices



Nominal price data from [PJM IMM](#); note that capacity auction results are impacted by the supply-demand balance as well as multiple revisions to capacity-market design

2 PJM's capacity prices increased due to multiple factors, including load growth

Data Center Load Growth

↑ 174% increase in auction revenues

Summer Capacity Ratings for CC/CTs

↑ 23 - 118% increase in auction revenues

Demand Curve Price Cap

↑ 68% increase in auction revenues

Adoption of ELCC Method

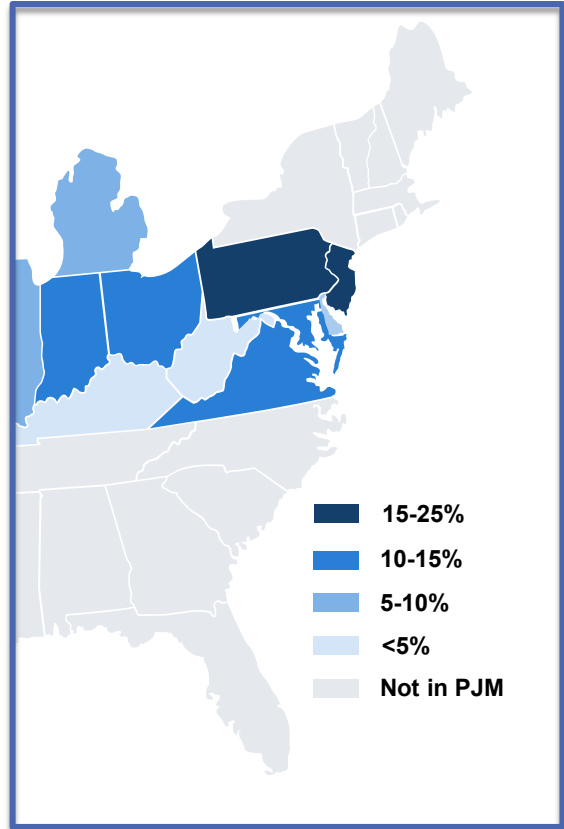
↑ 49% increase in auction revenues

Other major drivers included the exclusion of Reliability Must Run units from the auction supply curve and the withholding of exempt capacity. The resulting auction outcomes signal a need for new resources to meet the growing demand of the region. Some may therefore interpret the increase in clearing prices as indicative of prices that were, in retrospect, too low in previous auctions.

Source: Data from Monitoring Analytics' [IMM Analysis of the 2025/2026 RPM Base Residual Auction](#) Parts A through G

3 Significant increase in state-level retail prices

Average Increase in Nominal Prices: Dec. 2024 to Dec. 2025

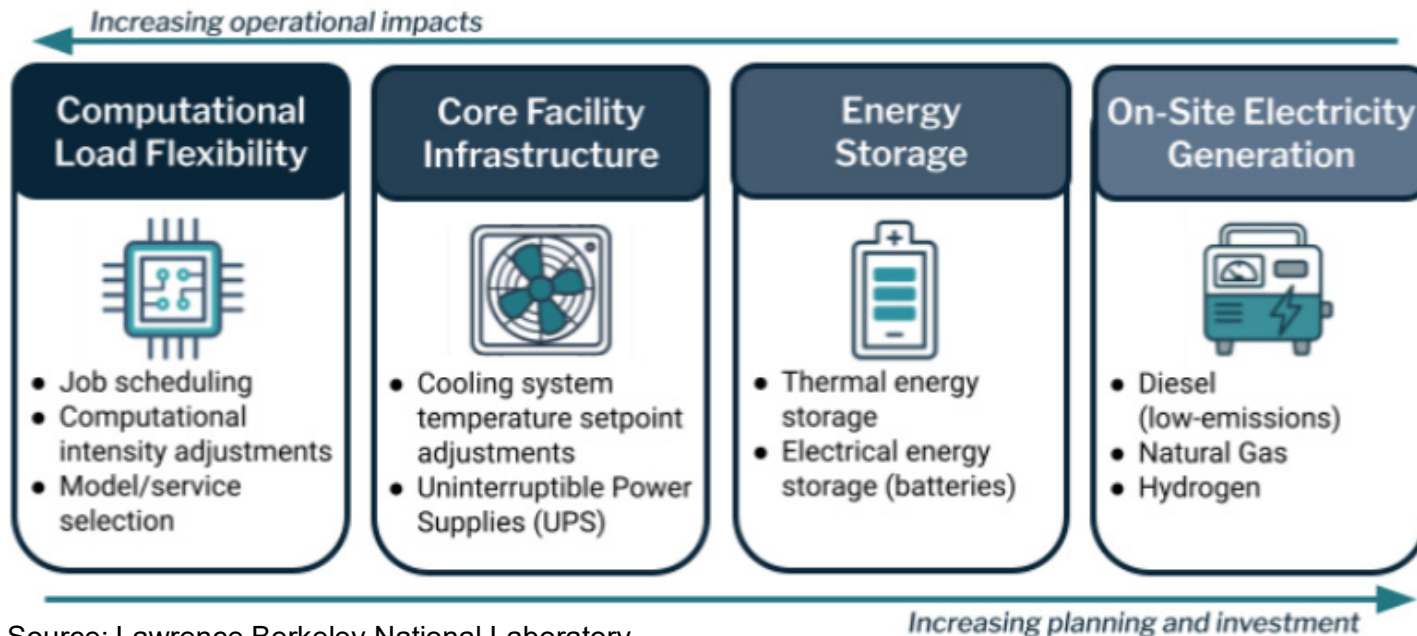


Capacity prices are one but not the only contributor to retail price increases

Notes and source: States with vertically integrated utilities are shielded to some extent from capacity auction price spikes because utilities can self-supply instead of purchasing capacity from PJM: from [EIA Electricity Monthly Update Dec. 2025](#)

Maximizing the use of the existing grid and encouraging bring-your-own-generation (BYOG) can facilitate large-load additions in the near-term

- New loads eventually require new supply and delivery infrastructure, but that is constrained and will take time; in the meantime, there are opportunities to minimize broader system impacts
- Three broad options for increasing asset utilization and reducing system-level impacts include:
 - Demand flexibility or onsite generation or storage from the new loads (*depicted in figure*)
 - Enabling data centers to “bring-their-own” offsite generation, storage, or load flexibility
 - Broader utilization of load flexibility, efficiency, storage, grid-enhancing technology, regional trade, etc.



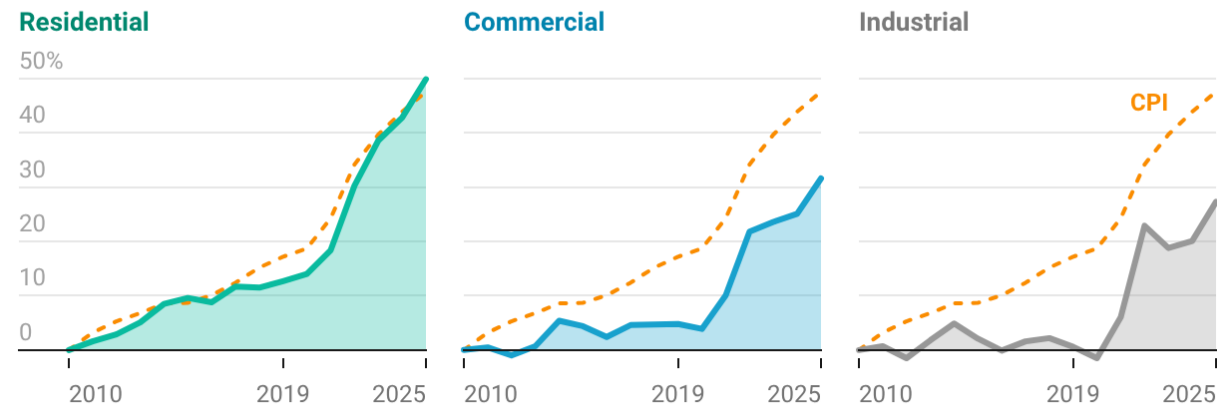
Some relevant recent studies on these options and their potential benefits include: [EPRI \(2026\)](#), [Brattle \(2026\)](#), [ASE \(2026\)](#), [Ross & Ewing \(2026\)](#), [Camus \(2025\)](#),

If growth occurs in a supply/delivery-constrained environment, protecting households may require allocating more total grid costs to the new loads

- Gap between residential and C&I prices has grown over time, with households bearing a larger share of costs; **C&I prices increased well-below the rate of inflation, not so for residential**
 - ▣ May be due, in part, to distribution cost growth disproportionately impacting residential customers, and desire to encourage economic development via lower prices for C&I customers
 - ▣ Gap between residential and C&I prices in 2025 was much higher in some states than in others
- **Large-load tariffs** are one approach to potentially protect residential customers in cases where rapid load growth increase average electricity costs (*see next slide*)

Percent Increase in National Average Retail Prices, by Sector

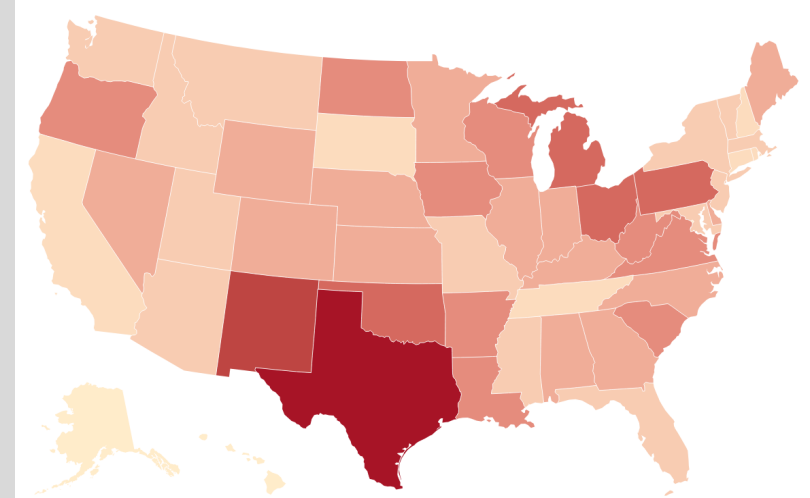
Percent increase since 2010 in nominal cents/kWh (not adjusted for inflation), compared to CPI



Source: EIA, BLS • Created with Datawrapper

Average C&I Price Discount Relative to Residential: 2025

20% 25% 30% 35% 40% 45% 50%



Source: EIA • Created with Datawrapper

Rapid data center buildout plus supply and delivery constraints can increase costs ➡ Interest in new large-load tariffs to mitigate impacts

- ❑ Large-load tariff info: [LBNL report](#), [E3 report](#), [data](#)
- ❑ Four themes of large load tariffs
 - ▣ Fairly allocate electricity system costs to cost causers
 - ▣ Mitigate utility and customer financial risks
 - ▣ Mitigate operational and resource adequacy risks
 - ▣ Accommodate needs of large-load customers
- ❑ Examples of types of provisions
 - ▣ Refined cost allocation approaches to ensure fair payments
 - Sometimes including payments for embedded costs
 - ▣ Min. duration & demand/payment, exit fees, reassignment
 - ▣ Upfront commitments, collateral, credit
 - ▣ Size, ramp times, load factor, BTM resources
- ❑ Other levers to mitigate impacts:
 - ▣ Interconnection, cost allocation among existing rate classes, load forecasting, information sharing, third-party gen, etc.
- ❑ *Note: to a degree, these new tariffs and processes may diverge from historical practice of industrial development rates that sought to encourage loads through accommodating tariffs*



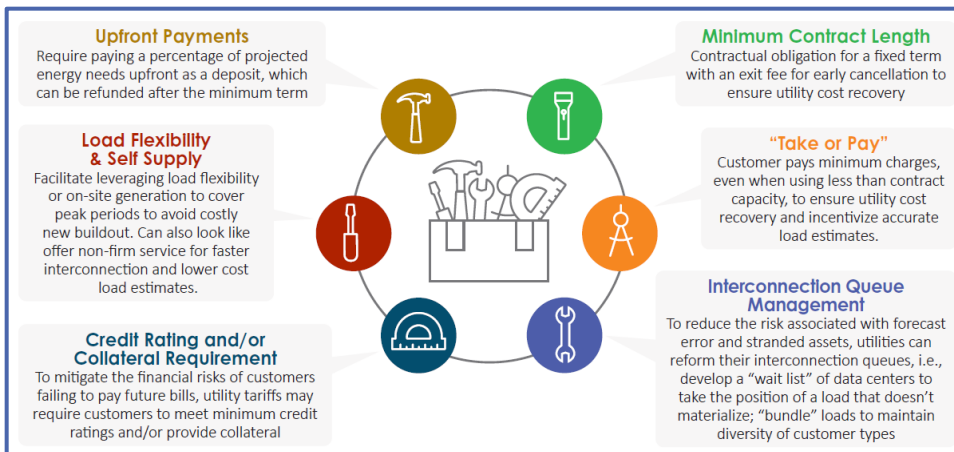
TECHNICAL BRIEF 1 |

January 2025

Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities

*Andrew Satchwell, Natalie Mims Frick, and Peter Cappers (Berkeley Lab)
Sanem Sergici, Ryan Hledik, and Goksin Kavlak (The Brattle Group)
Glenda Oskar (U.S. Department of Energy)*

Electricity demand from large-load customers such as data centers is projected to grow significantly in the near term. While these large loads play an important role in advancing technology innovation and economic growth in the United States, meeting their energy needs requires utilities and regulators to consider important financial and operational risks from underutilized investments or insufficient energy supply, infrastructure, and operational capabilities, with implications for all ratepayers. This paper provides an overview of how utilities and regulators are managing these risks through different tariffs, including rate structures and service agreements. Utilities, regulators, customers, and other stakeholders can use this paper as a foundation when discussing issues and sharing perspectives on developing new large load tariffs or reviewing existing ones.



Example statements that suggest possible benefits for other customers, but positive outcomes are not assured and require monitoring



Georgia PSC approved utility to serve new large loads, conditioned on growth placing **downward pressure on bills of \$8.50/mo** for residential customers from 2029-2031



PG&E estimates that 10 GW of data center growth could **lower customer bills by 10%** by utilizing existing infrastructure and spreading fixed costs across more electricity usage

DTE Energy



Michigan PUC conditionally approved data center contracts that DTE estimates will **lower residential costs by 8%**; separate agreement with Google claimed to have **\$1.7 billion in lifetime benefits**



Entergy projects **\$5 billion in savings over 20 years** for their customers in Arkansas, Louisiana and Mississippi due to the data center agreements in those states



MDU estimates Applied Digital's data centers **saved customers \$70 in previous year** by tapping into underutilized power and, with full build, savings could rise to \$250/year



Centerpoint estimates **~\$4 billion savings** over 10 years for their Texas residential and commercial customers associated with 10 GW of new industrial load



NIPSCO estimates \$1 billion in bill credits over a 15-yr contract with Amazon data centers in Indiana, equal to **residential bill savings of \$7-9 per month** in 2032 and beyond



Xcel estimates that its contract with Google in Minnesota will result in **\$1.1 billion in total benefits** for other customers over its 15-year term

Emphasizing the point that these are possible or stated benefits, there is risk that the new tariff structures will be insufficient to fully protect other customers (e.g., see Martin & Peskoe 2025)

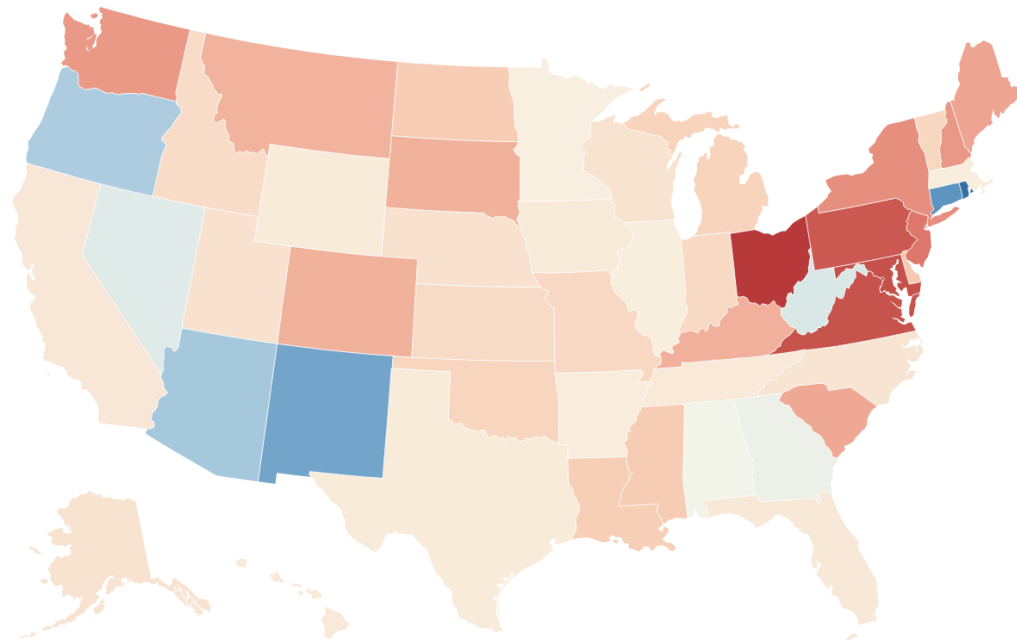
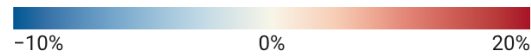
Early 2026 price indicators and IOU rate requests – *What's coming down the pike*

Retail prices continue to climb in 2026: all-sector average (left) and residential (right) price changes, Jan-Apr 2025 to Jan-Apr 2026

ALL-SECTOR AVERAGE

Percentage Change in All-Sector Retail Electricity Prices: January-April 2025 to January-April 2026

Percentage change, adjusted for inflation in 2025\$

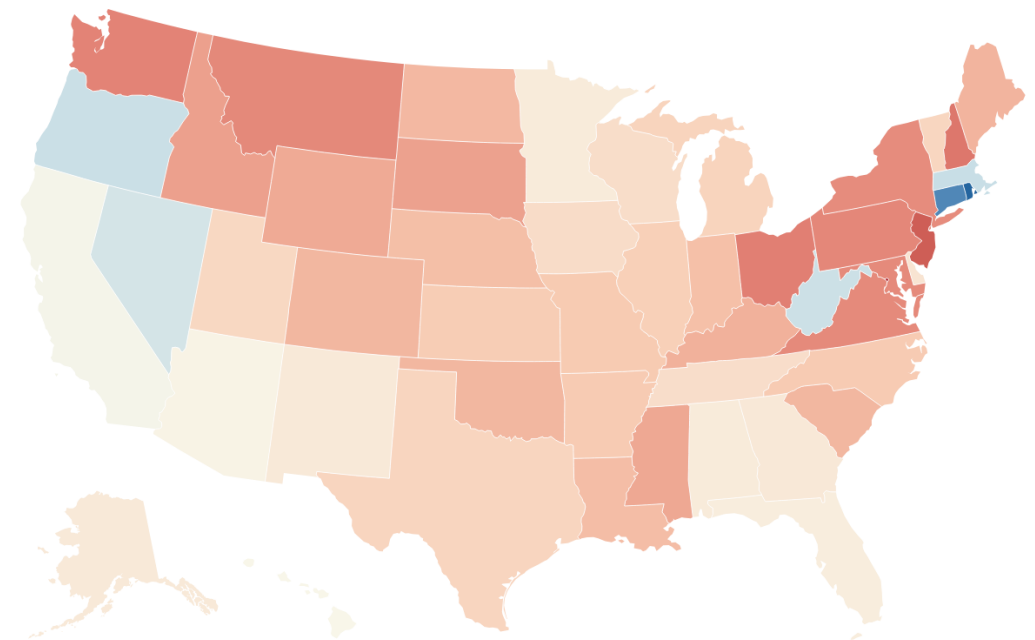
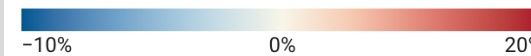


Source: EIA • Created with Datawrapper

RESIDENTIAL

Percentage Change in Residential Retail Electricity Prices: January-April 2025 to January-April 2026

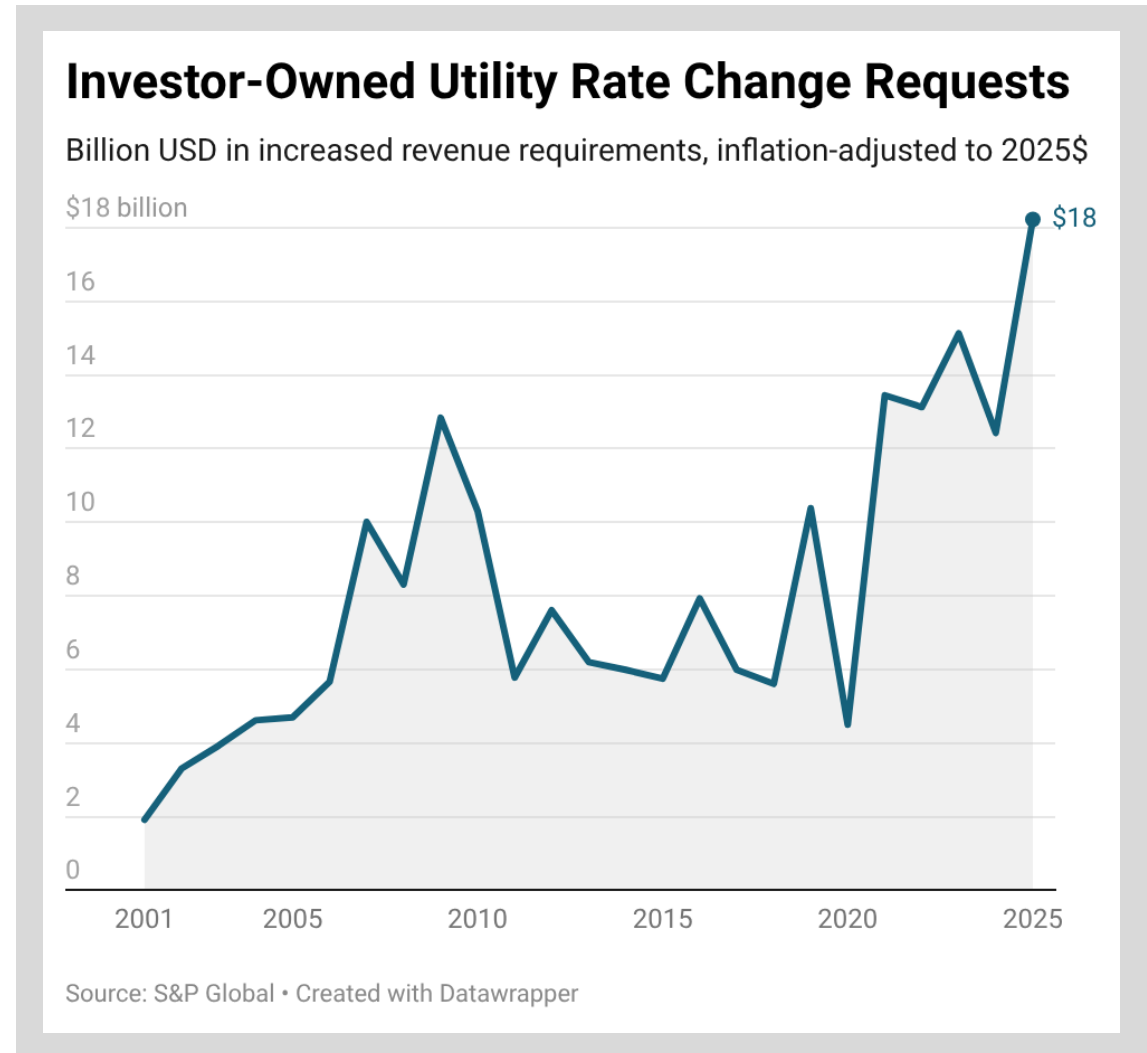
Percentage change, adjusted for inflation in 2025\$



Source: EIA • Created with Datawrapper

Investor-owned utility revenue increase requests in 2025 were higher than experienced in decades, suggesting continued price increases in 2026

- ❑ Investor-owned utility (IOU) revenue increase requests in 2025 = **\$18 billion** (*focusing on subset of requests, see below*)
- ❑ IOU revenue increase requests in 2025 exceeded any point since the mid-1980s, suggesting continued price increases in near term as regulators consider the requests
- ❑ S&P data reflect major ‘base rate’ requests and some rate riders, but generally exclude fuel adjustment charges, storm recovery costs, and other limited-term riders; the data also only includes IOUs, as other utility types do not generally file with state PUCs
- ❑ Data therefore represent a directional signal for changes in costs and near-term retail electricity prices, but are incomplete



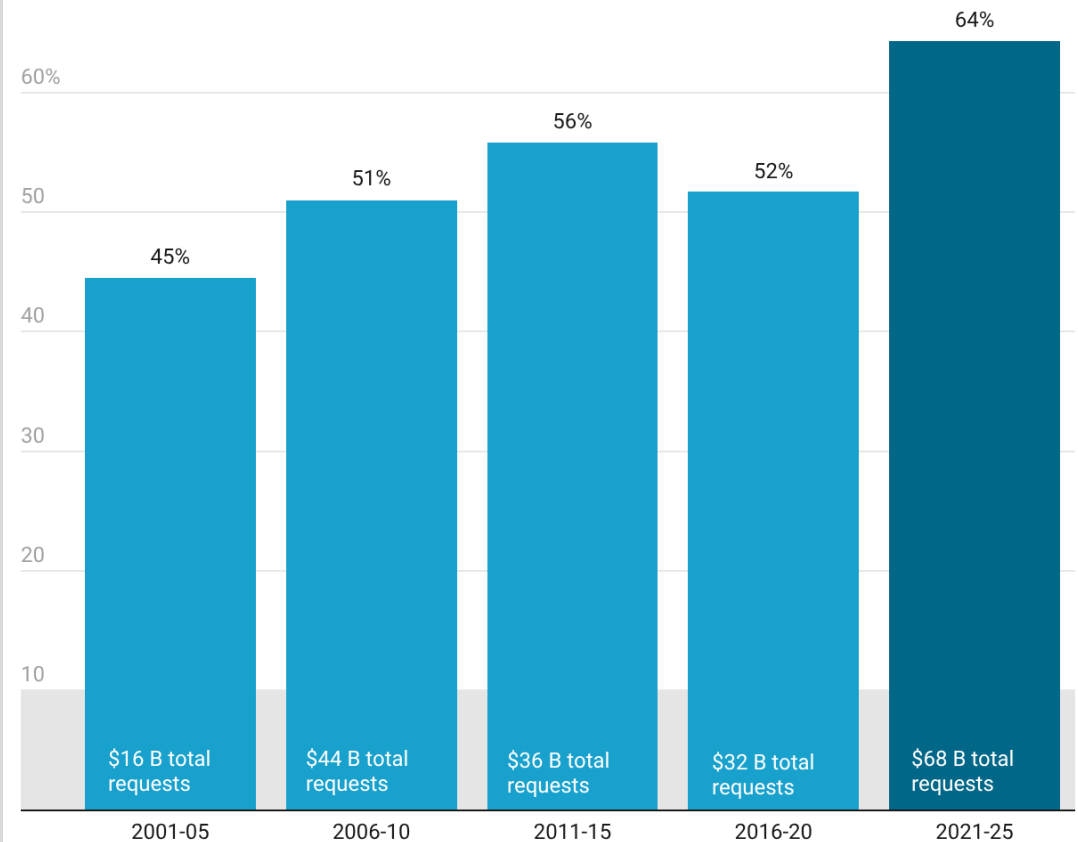
Notes: (1) Source: S&P Global, LBNL Analysis; (2) Rate case sample includes all “major” rate cases that impact base rates and would result in a rate change of at least \$5 million, inclusive of some limited issue rider cases. Fuel cost adjustments and limited-term rate riders are not generally captured.

Further suggesting price increases, regulators approved larger fractions of utility revenue increase requests over the last 5 years than previously

- Over the last five years, public utility commissions (PUCs) approved, on average, **64%** of the dollar value of revenue increase requests; in 2025, it was **66%**, on average
- This is higher than in the previous two decades, during which the average approval percentage was **52%**
- Higher approval levels could imply: higher-quality utility requests; lower levels of scrutiny; or changes in operating, regulatory or legislative environment
- Regardless of the cause, high IOU requests plus high levels of approval suggest additional upward price pressure in the near-term barring load growth that exceeds revenue requirement increases

Regulatory Approval Levels for IOU Rate Increase Requests

Approvals as a percent of revenue increase requests

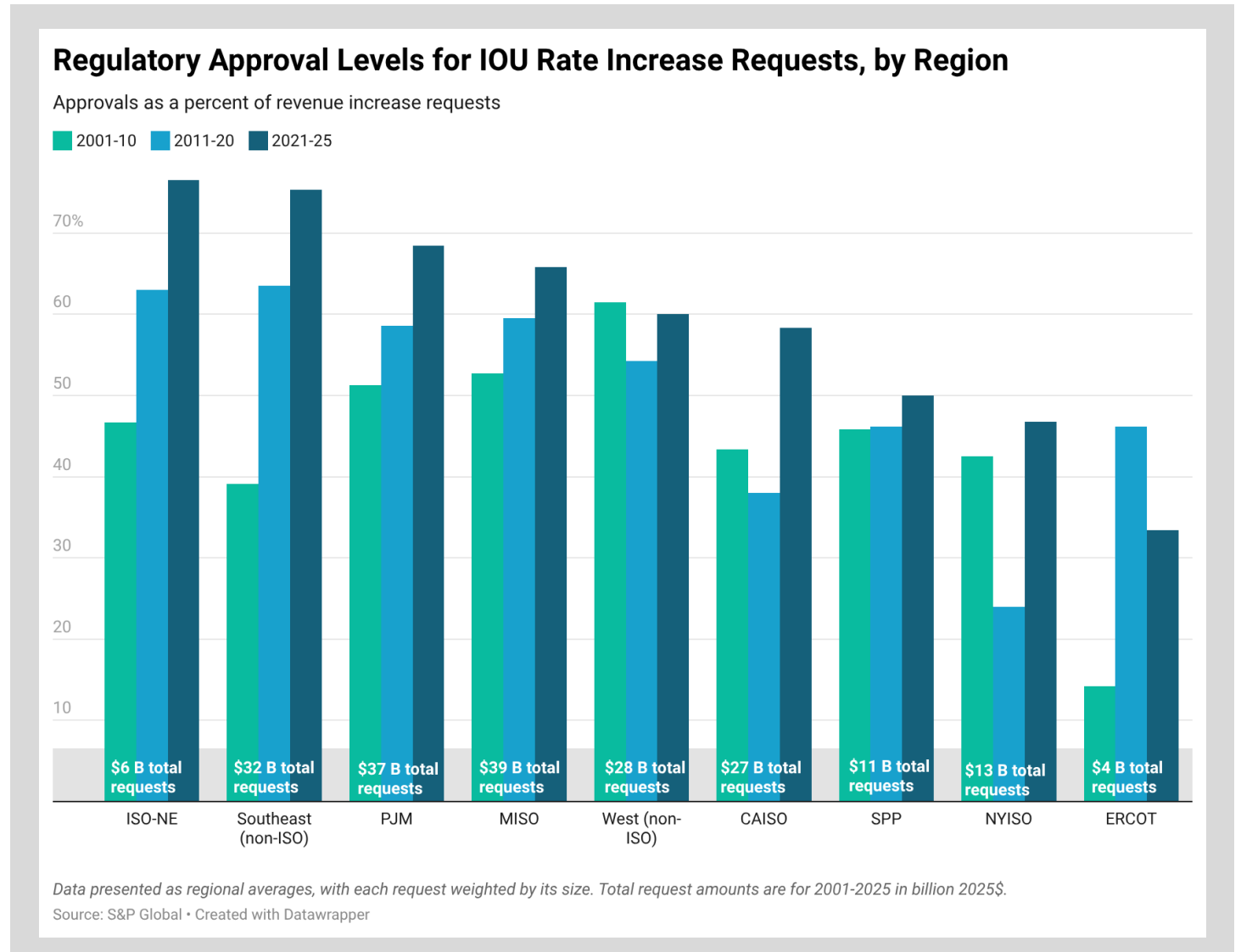


Data presented as averages, with each request weighted by its size. Total request amounts are in 2025\$.

Source: S&P Global • Created with Datawrapper

Recent approval percentages in most regions were higher than in the past: New England and the Southeast approved higher fractions of requests

- Regulatory approval levels for IOU revenue increase requests vary by region, as do time trends
- New England and Southeastern PUCs have recently approved higher percentages, and approval levels have, over time, significantly increased
- Approval levels were relatively high and have also increased among PUCs in PJM and MISO
- California witnessed recent increases in approval levels, but overall percentages were lower than in the regions noted above

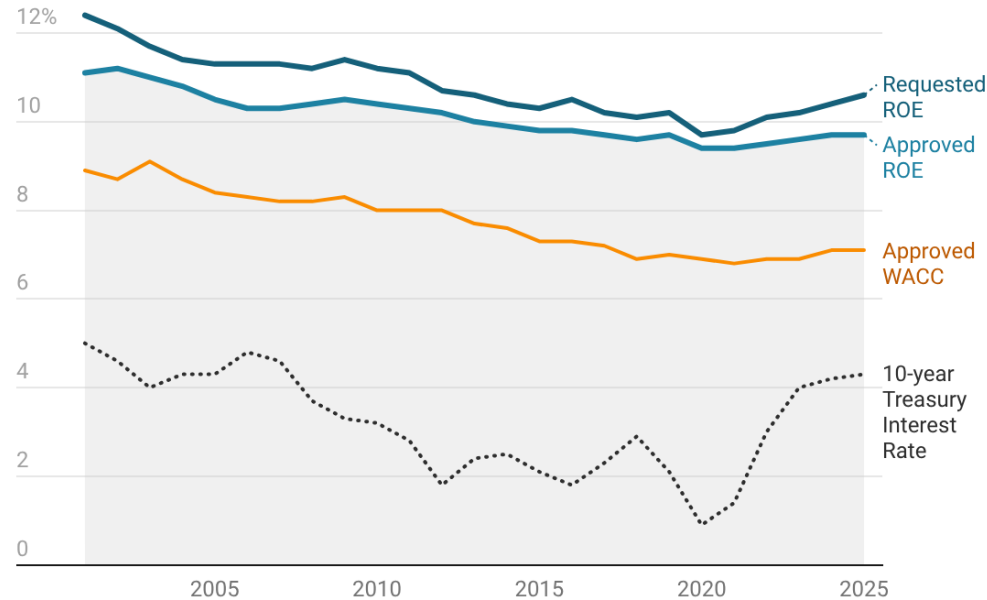


Authorized return-on-equity (ROE) for IOUs also impacts retail rates, and has trended slightly upwards in recent years as interest rates increased

- Regulators in California and the Southeast have recently authorized higher ROEs than in other regions, whereas New England and New York regulators have authorized lower ROEs

Requested and Approved IOU ROE, Approved WACC, and Relationship to 10-year Treasury Interest Rate

Values for ROE and WACC are mean values among all requests or approvals in a year

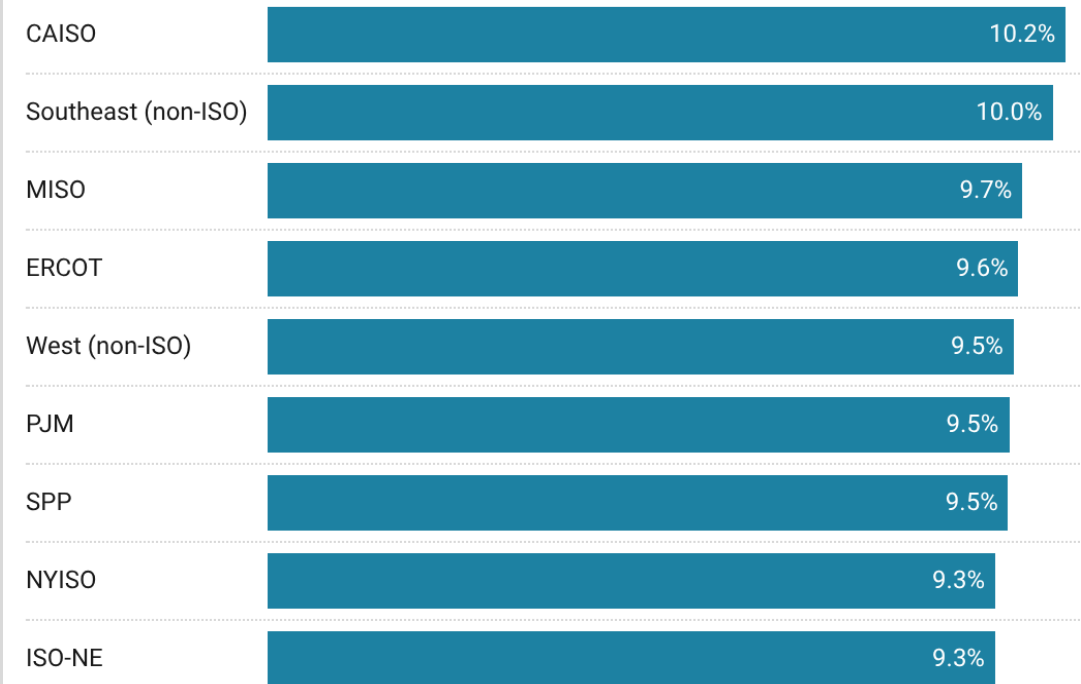


Given time-lags between requests and approvals, the gap between the two values in any individual year does not reflect approval percentages.

Source: S&P Global • Created with Datawrapper

Authorized Return-on-Equity by Region: 2021-2025

Data shown are averages among rate cases in each region



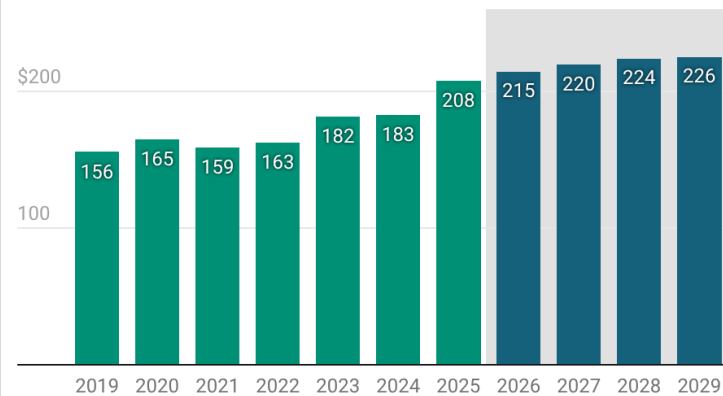
Source: S&P Global • Created with Datawrapper

Several additional indicators suggest continued upward price pressures in the near- to medium- term

- IOU capital expenditures have outpaced inflation, and are expected to continue to do so—will drive retail prices higher unless load increases faster than annualized costs (*left figure*)
- In addition to the heightened price of distribution and transmission equipment noted earlier:
 - The expected installed cost of combined-cycle and simple-cycle natural gas plants to be built through 2030 is ~65-90% higher than recent historical builds even after adjusting for inflation (*middle figure*)
 - The national-average power purchase agreement (PPA) price for solar and wind has increased by 60% and 100%, respectively, since 2020 (after adjusting for inflation) (*right figure*)

IOU Total Annual Capital Expenditure

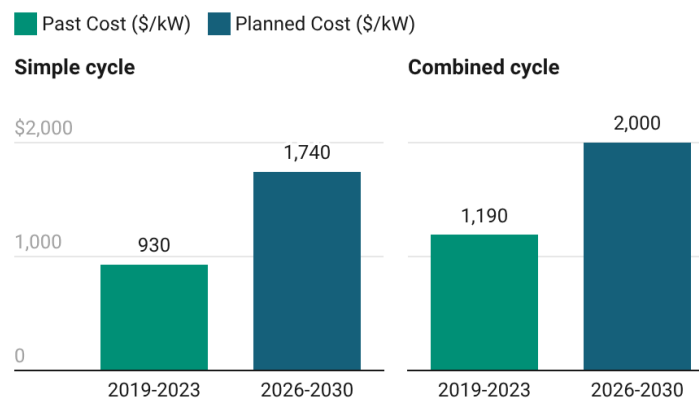
Billion \$, inflation-adjusted to 2025\$



Source: EEI; actual data through 2024, projections after 2024 • Created with Datawrapper

Installed Cost of Natural Gas Power Plants

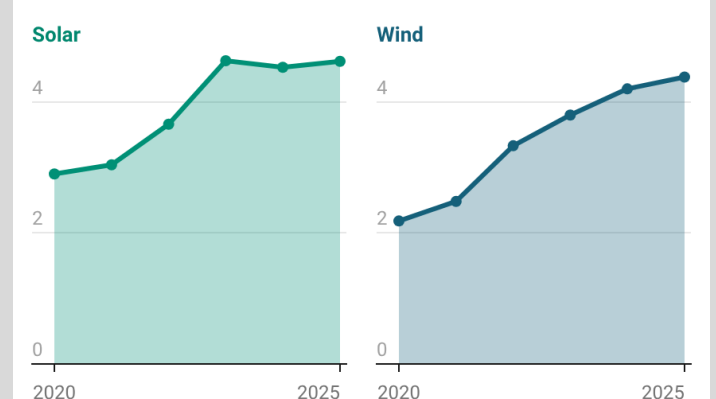
CapEx in \$/kW, inflation-adjusted to 2025\$



Source: EIA (past costs), Halcyon (cost estimates) • Created with Datawrapper

PPA Price Indices for Solar & Wind Energy

Levelized cents/kWh, inflation-adjusted to 2025\$



Source: LevelTen Energy, LBNL • Created with Datawrapper

For more information



This Overall Project Currently Includes Multiple Products

For more information, contact: [Ryan Wiser \(rhwiser@lbl.gov\)](mailto:rhwiser@lbl.gov)

Annual and periodic data updates

Compiles and synthesizes data as it becomes available, including this update

Data visualization tools

Allows users to explore some of the data compiled under this research effort

Peer-reviewed journal article

Highlights a subset of the trends through 2024, with a focus on statistical analysis of broad drivers

These products can all be found at: <https://emp.lbl.gov/retail-electricity-price-trends-and-drivers>

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