IPA Power Hour — Understanding Electricity Prices: *Trends & Tools in the U.S. and Illinois*

April 24, 2026

IPA Power Hour Webinars

ILLINOIS POWER AGENCY

- **Today's Power Hour:**
  - The session will dive into how electricity prices are set, recent national and Illinois trends, key drivers behind price changes, and market developments shaping future costs. Attendees will also learn about tools and strategies that states are deploying to navigate these evolving dynamics.

Power Hour is a series of educational and informative presentations on a wide range of clean energy topics and emerging issues.

- Started in 2021, the Agency has hosted 37 webinars in the Power Hour series, inviting local and national experts and thought leaders.

WEBINAR ARCHIVES: https://ipa.illinois.gov/about-ipa/ipa-events/previous-power-hour-events.html

Popular Power Hour Topics

The State of Wind Energy

Renewable Energy Financing: Distributed Solar

Clean Energy Future for Public Schools: Challenges and Solutions

ILLINOIS POWER AGENCY

ILLINOIS POWER AGENCY PRESENTS

IPA Power Hour—*Understanding Electricity Prices: Trends & Tools in the U.S. and Illinois*

April 24

Will Gorman
Research Scientist,
Lawrence Berkeley
National Laboratory

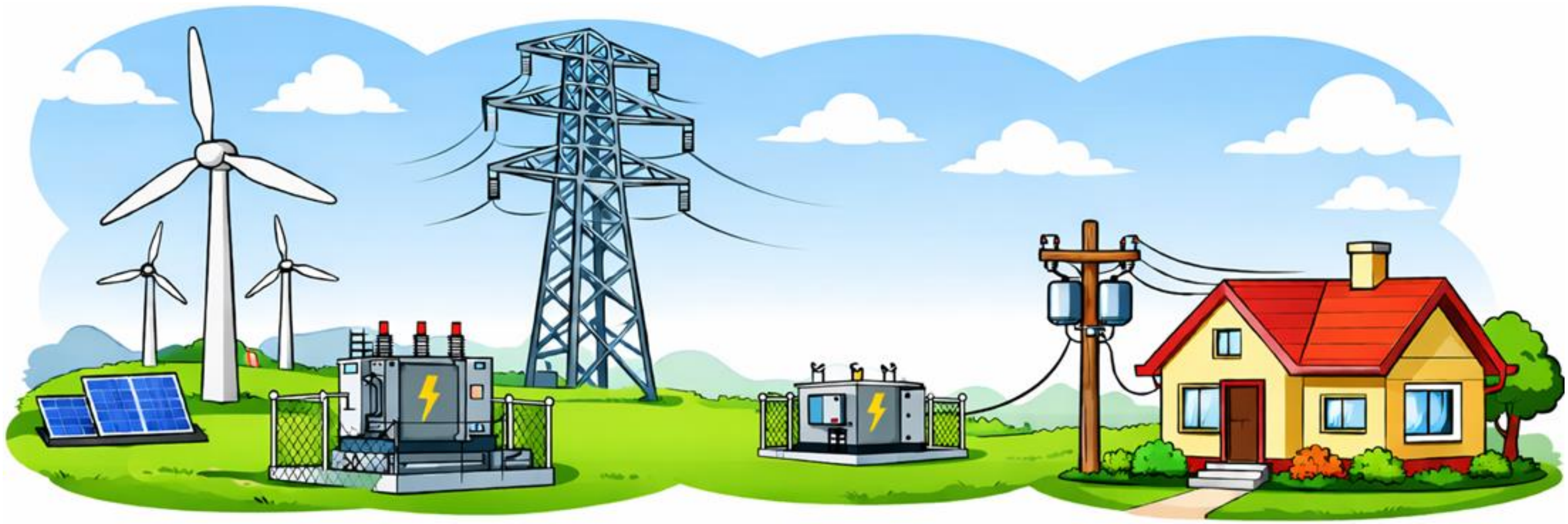
Nathan Miller
Senior Director,
Energy + Environmental
Economics, Inc.

James Rouland
Planning & Procurement
Bureau Chief,
Illinois Power Agency

Overview of Electricity Prices, Markets, and Regulation

Jim Rouland
IPA Planning & Procurement Bureau Chief

Visualizing the Grid



Components of an Electricity Price

Electricity Price = $\underbrace{\text{Energy + Capacity}}_{\text{Sometimes combined on customer bills}}$ + $\underbrace{\text{Transmission + Distribution}}_{\text{Includes other components – special utility or state programs, RTO ancillary charges, etc.}}$

Energy	The electricity you use/consume, usually represented in the costs in an hour (cent/kWh or $/MWh)
Capacity	Paying for enough power plants and other resources to be available when they are needed – also considered "reliability" cost ($/MW-day)
Transmission	Moving power long distances across the high-voltage grid (cent/kWh for small customers, $/MW or demand charge for large customers)
Distribution	Delivering power locally to homes and businesses (cent/kWh)
Other Components	Programs, secondary market charges, or support costs. Varies by utility, market, and customer – could include wholesale market ancillary services/costs; special utility programs or charges; etc. (often cent/kWh but can also be a demand charge)

Who Manages vs. Regulates in Illinois?

ILLINOIS POWER AGENCY

	Manages	Regulates	Informs
Electricity Prices/Market	PJM/MISO	Federal Energy Regulatory Commission	Generators & Customer Usage
Capacity Prices/Market	PJM/MISO	Federal Energy Regulatory Commission	Generators & Customer Demand
Transmission Prices	Transmission Developer* & PJM/MISO	Federal Energy Regulatory Commission	Generators, Customers, ICC, Advocacy Groups
Distribution Prices	Local Utilities (Ameren, ComEd, MidAmerican)	Illinois Commerce Commission (ICC)	Customers, Advocacy Groups, Small Generators

Manage – oversees/implements market; completes investments; oversees procurements
Regulates – authority ensuring compliance with statutes, regulations, etc.
Informs – provides data (costs, availability, needs information, etc.) and recommendations

Transmission Developers have often been the local utility companies who build and operate the transmission grid in their territory; however, other entities have been growing in this space. These include merchant transmission owners and generators.

How "need" affects price.

ILLINOIS POWER AGENCY

All energy markets and system costs are directly and directionally informed by causes and effects.

- **Energy prices** – set through PJM/MISO markets as the ***cost of serving demand at a specific time and location***; informed by customer usage and generator submitted prices (the last power plant to be called on sets the price for that hour - the *marginal price of power*).
- **Capacity prices** – established through a PJM/MISO ***auction***; informed by RTO's forecast customer demand, bids from generators, and RTO market rules and reliability standards
- **Transmission prices** – costs to build, maintain and upgrade high voltage grid to meet customer and generator needs; established through ***FERC formula rates or competitive procurements by the RTO*** (PJM/MISO) and approved by FERC.
- **Distribution prices** – costs to build, maintain, and upgrade the lower voltage grid (local) to meet customer needs; established through an ***ICC rate case***

Amped Up: Factors Impacting Retail Electricity Prices in the United States

Ryan Wiser, Galen Barbose, Peter Cappers, Jeffrey Deason, Sydney Forrester, Will Gorman, Eric O'Shaughnessy

Lawrence Berkeley National Laboratory

Ryan Hledik, Long Lam, Audrey Yan

The Brattle Group

April 2026

This work was funded by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views and opinions of the authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Image source: OpenAI DALL-E

Objectives and Scope of Study

Context: Retail electricity prices have recently increased nationally in concert with economy-wide inflation, but with significant differences among states

Goal: Add nuance to current discussions about the "national electricity affordability crisis" and the scapegoating that often occurs when identifying causes of that "crisis"

STUDY SCOPE

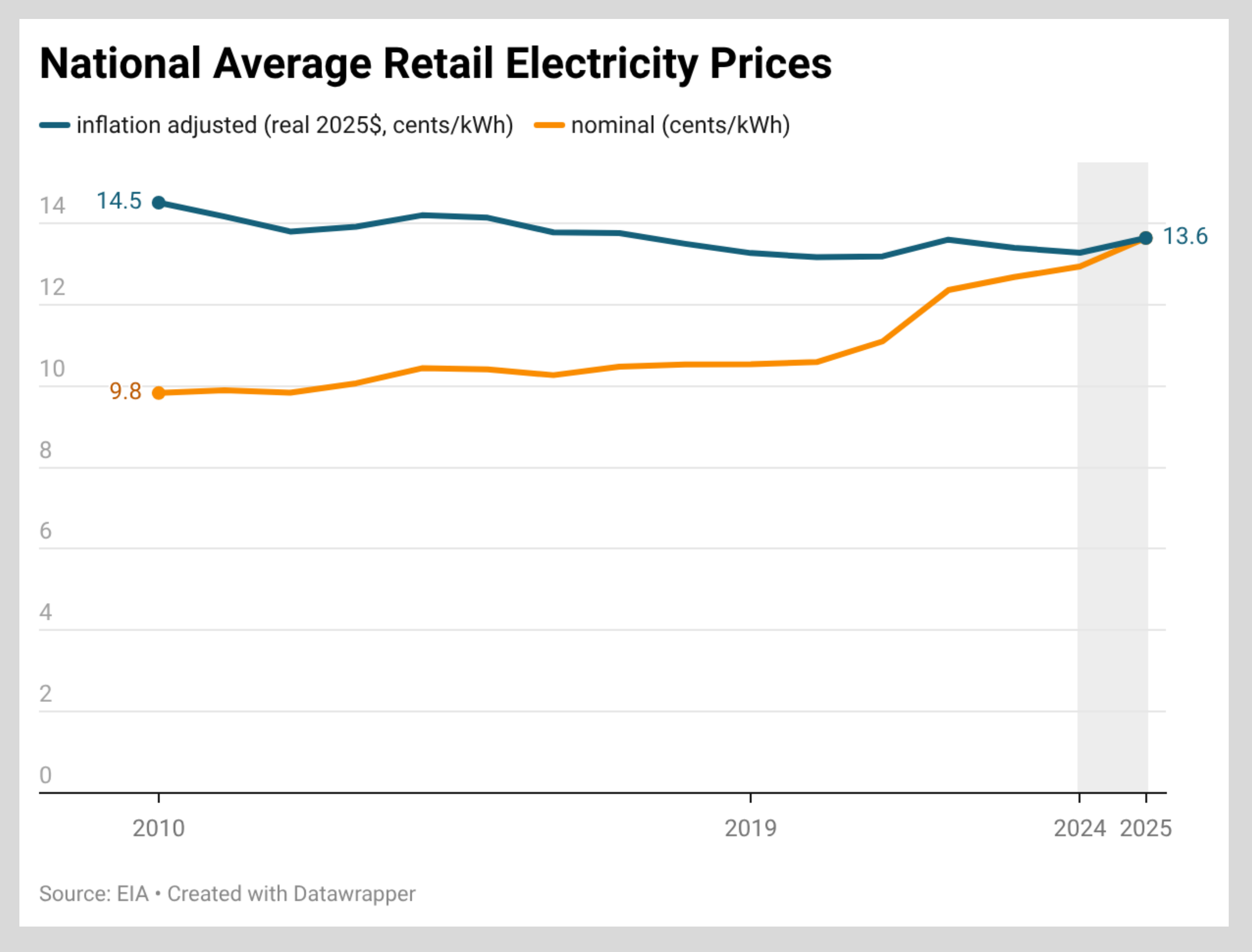
Summarize recent retail electricity price trends	Assess drivers of recent retail electricity price changes
• National- and state-level price trends, since 2010 and 2019	• Most-likely drivers of state-level price changes, 2019 to 2025

Trends – *Level-setting on historical data*

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
- In nominal terms (not inflation-adjusted), national-average prices increased **29%** from 2019 to 2025, **39%** since 2010
- Adjusting for inflation, real prices in 2025 were **3% higher** than 2019, **6% lower** than 2010

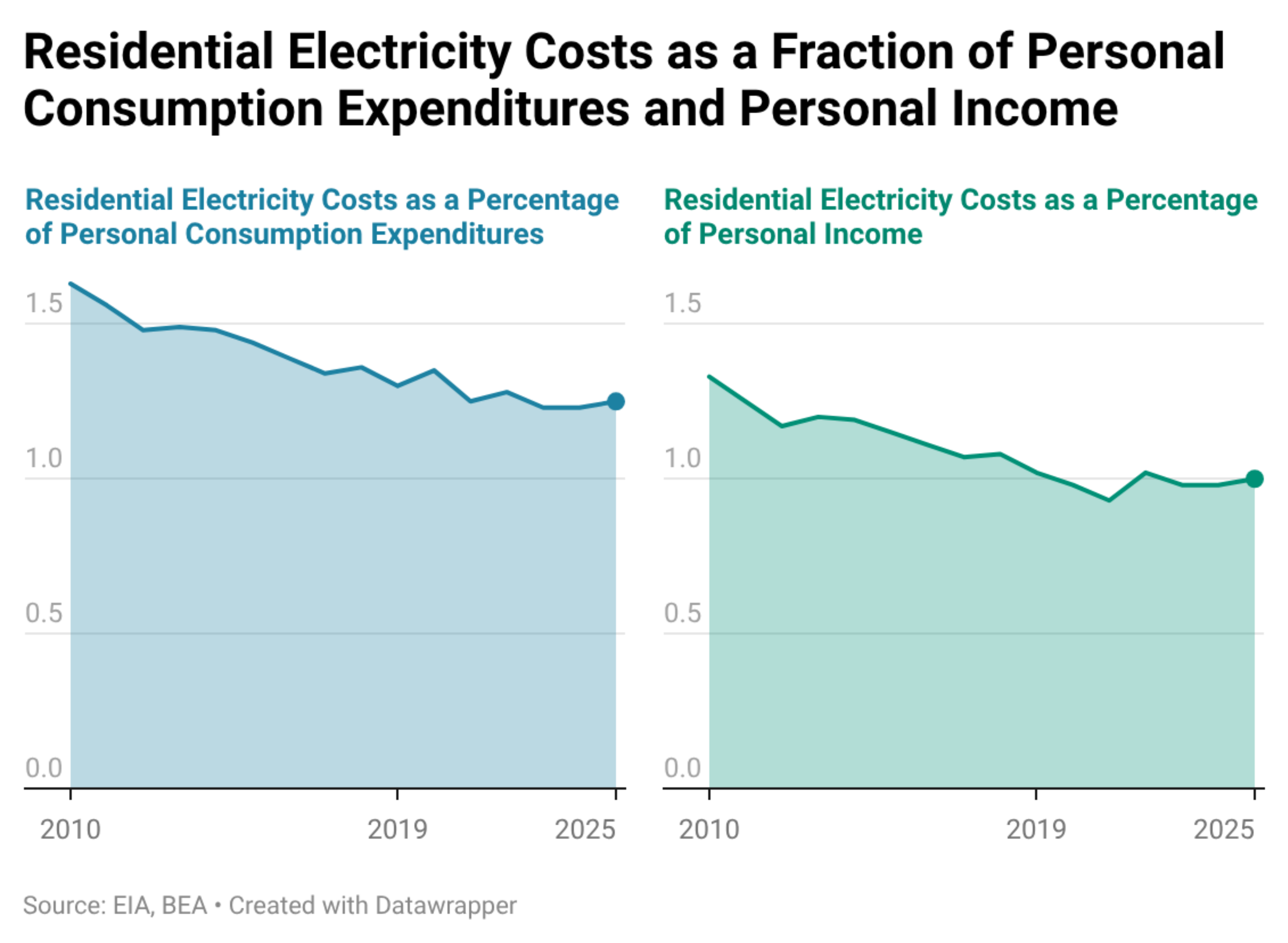
Represents the "all-in" price, equivalent to total customer bills (including volumetric, demand, and fixed charges) divided by total retail electricity sales, and covers all costs associated with the provision of retail service (generation + transmission + distribution)



National residential electricity costs as a fraction of personal expenditure *(left)* and income *(right)* trended down for decades, but increased in 2025

- Total residential electricity costs as a fraction of personal expenditure equaled 1.25% in 2025, near an all-time low—but slightly above 2024 level
- Total residential electricity costs as a fraction of total income was also near an all-time low, at 1.0%—but slightly above the 2024 level

Note: Costs as a percent of income use personal income estimates from the Bureau of Economic Analysis, which are generally larger than household income estimates reported in the U.S. Census for reasons described in Katz. The percentages reported on this slide also differ from the electricity burden estimates reported later, which are based on consumer survey responses.

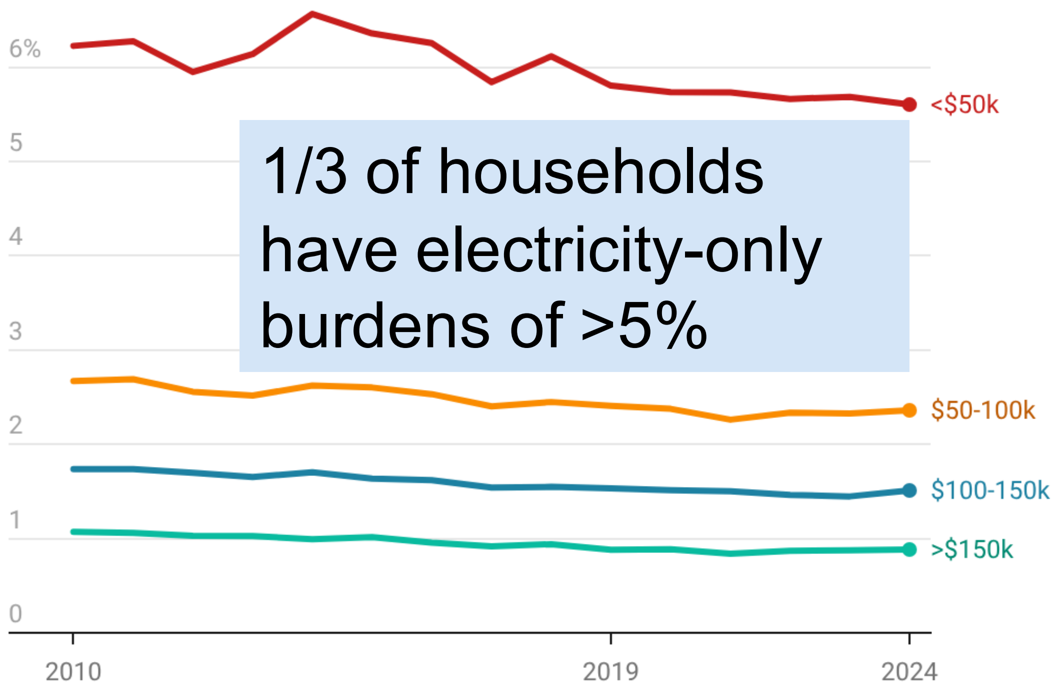


Regardless of trends at the national level, energy expenditures are a major hardship for many households and trends vary dramatically across states

~1/3 of households are heavily burdened

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

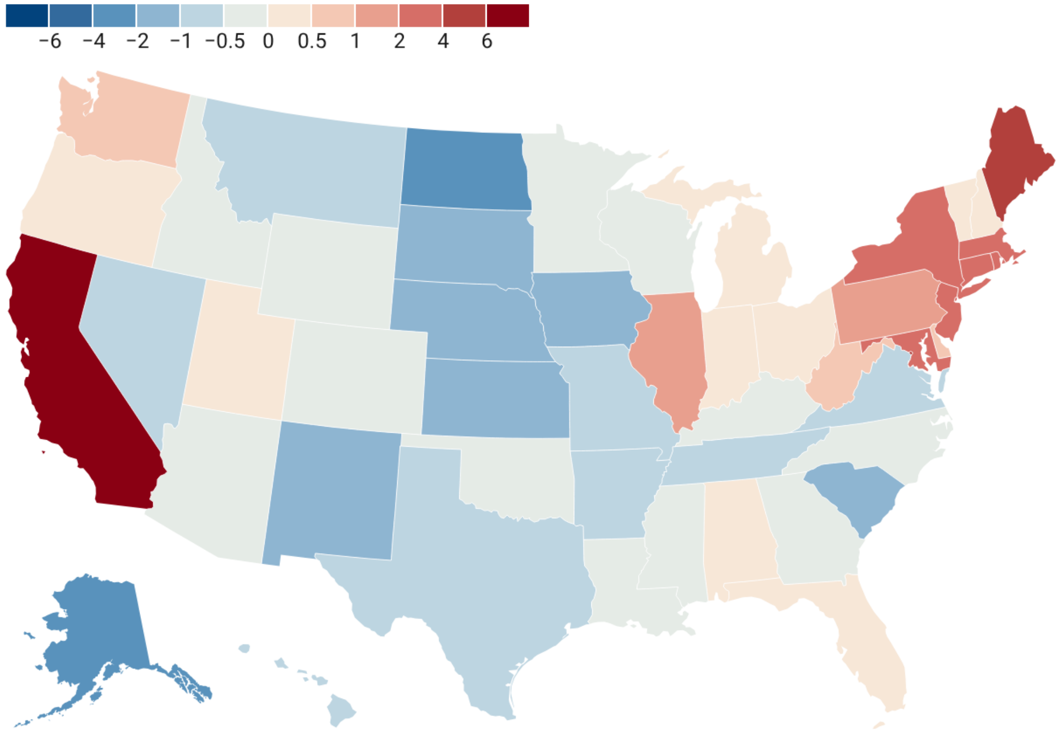
Electricity burden for average household in each income bracket



National trends mask state-level variation

Change in Average Retail Electricity Prices: 2019-2025

Real cents/kWh (inflation adjusted, 2025$)



Source: EIA • Created with Datawrapper

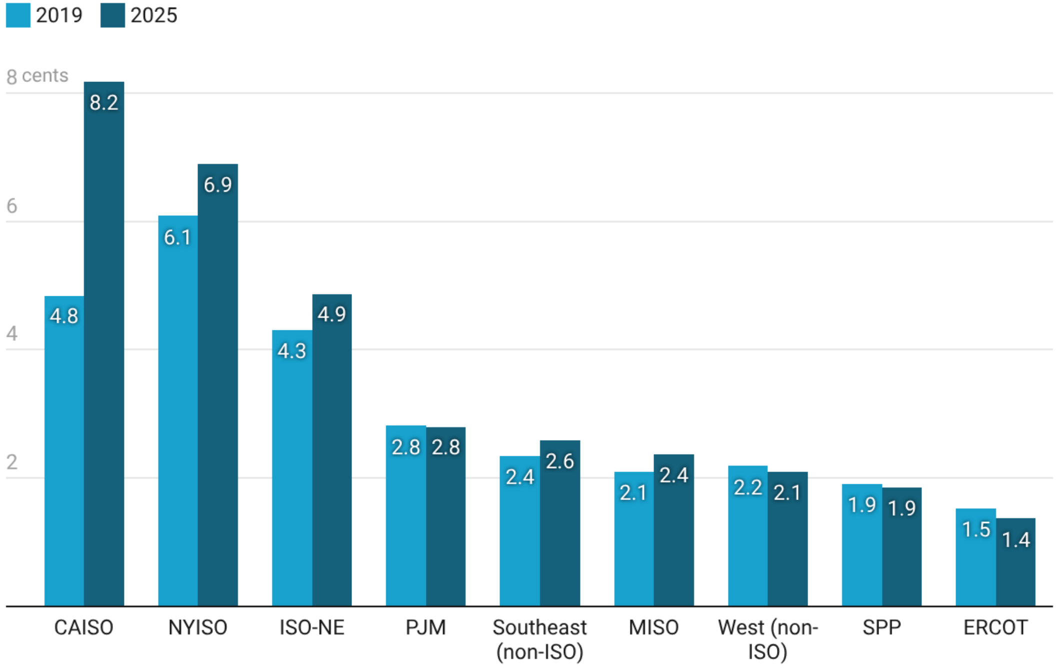
Drivers – *Understanding state variation, 2019-2025*

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

- IOU distribution infrastructure spending hit an inflection point ~2014, has since been rising ~4x faster (in real dollars) than prior 20 years
- Impact of distribution costs on retail prices is difficult to estimate, requires consideration of OpEx and CapEx; figure roughly estimates the price impact for IOUs from 2019-2025
- Price impacts span a wide range: **highest distribution-related prices and price increases in CAISO, NYISO, and ISO-NE**
  - CAISO prices impacted by wildfire mitigation, and both OpEx and CapEx
  - All 3 regions impacted by reductions in 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.

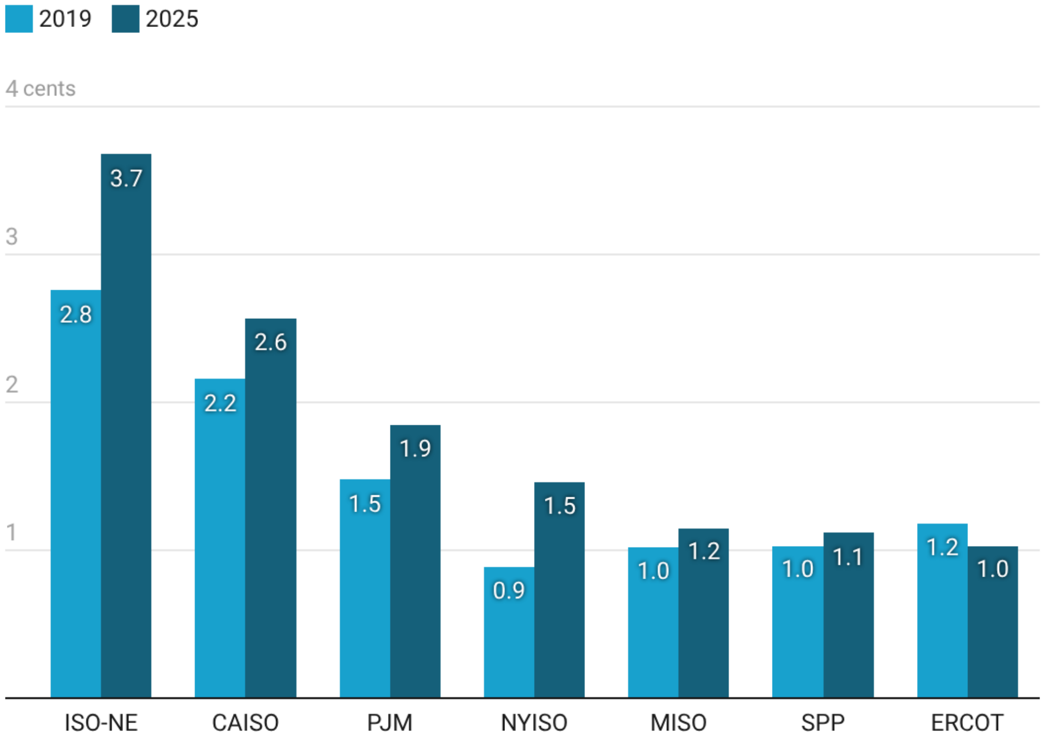
Source: FERC Form 1 • Created with Datawrapper

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

- Transmission costs are highest in and increased the most in **ISO-NE, up 0.9 ¢/kWh from 2019-2025 in real dollars**
  - Driven primarily by reliability, replacement of aging infrastructure, 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 desire to connect new renewable sources
- Transmission costs are generally lower and changed less in ERCOT, MISO, and SPP
- Note: higher transmission costs can lower retail prices <u>**if**</u> used to reduce supply costs

Transmission Costs in ISO Regions: 2019 and 2025

Average cost of transmission, inflation adjusted to 2025 cents/kWh

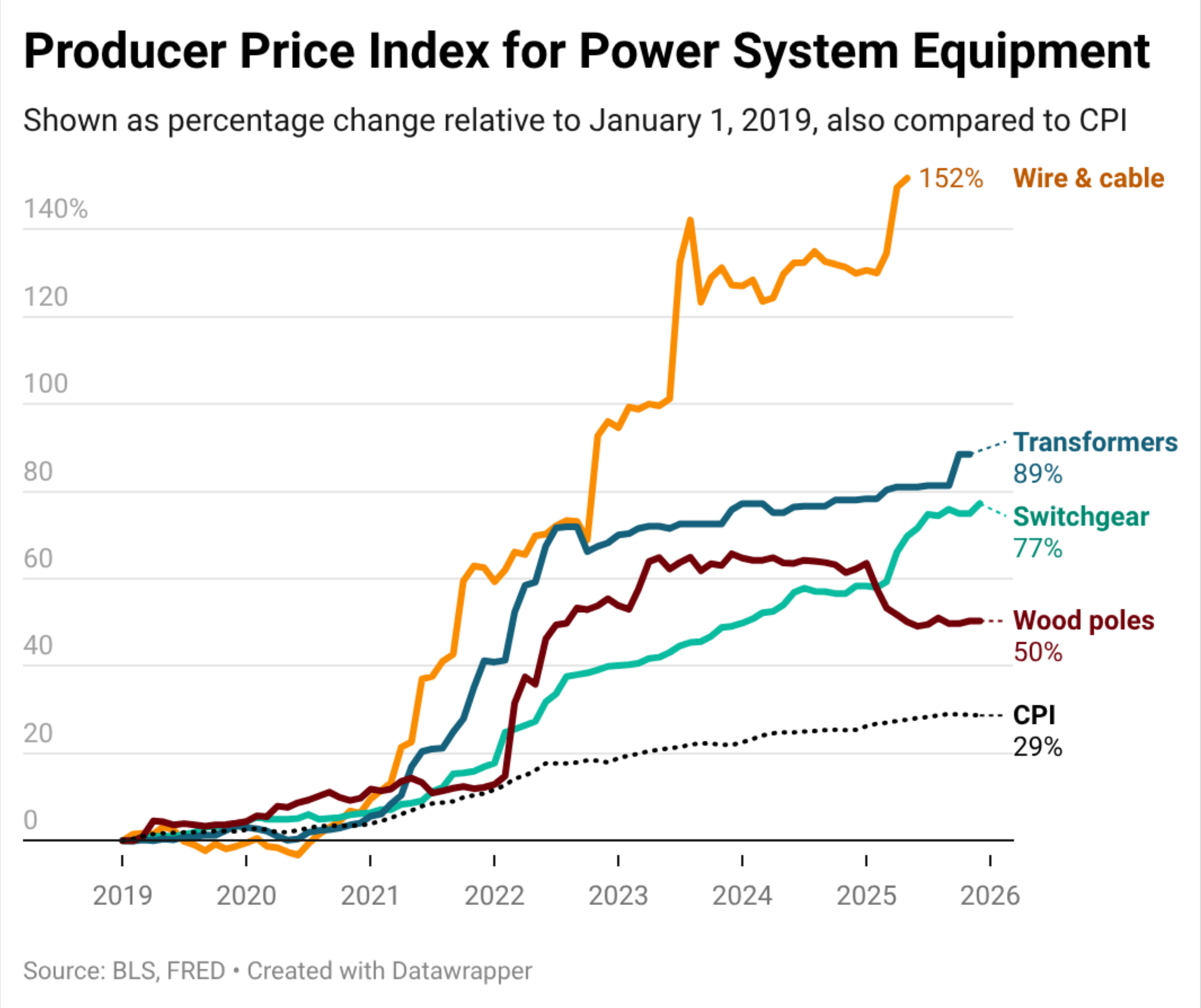


Absolute numerical values across states are not fully comparable given different definitions of costs included in the "transmission" category. Approximations needed in some cases.

Source: Market monitor reports, ISOs, regulatory filings. • Created with Datawrapper

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

- T&D investment driven by asset replacement, hardening, expansion
- Regardless of cause, supply-chain constraints and elevated equipment prices have contributed to the resulting overall cost increases
- Figure shows producer price indices for various goods 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, as shown



Storm recovery and wildfire mitigation costs have significantly increased prices in some states—can be among the largest drivers of price changes

- **Storms** result in **reactive** investments: system repairs
  - Influence on prices depends on frequency and extremity of storms, cost recovery period, and previous hardening
  - **Greatest impacts on East & Gulf coast:** sometimes >1 ¢/kWh

Recent Estimates of Utility Storm Recovery Price Impacts

Price estimate represents actual or likely impact on (mostly) residential prices in year shown, but some cost recovery mechanisms are short duration (i.e., the reported impact is temporary) whereas in other cases costs are securitized and reported price impacts will persist for as many as 20+ years. Normalized 1-year cost estimates represent the total costs as if recovered in a single year. Data are imperfect and should only be used to illustrate the wide range of and significant impacts. Includes recent estimates for only a subset of utilities.

Utility	State	Year	Duration	Price impact (cents/kWh)	Normalized 1-year cost (cents/kWh)
Duke Energy Florida	FL	2025	1-year	3.2	3.2
Central Maine Power	ME	2025	2-years	2.5	3.2
Tampa Electric Company	FL	2025	1.5-years	2.0	3.0
Entergy Louisiana	LA	2025	15-years	1.4	20.0
Florida Power & Light	FL	2025	1-year	1.2	1.2
Central Florida Electric Coop.	FL	2025	temporary	0.9	1.4
NYSEG	NY	2025	6-12 years	0.9	8.4
SWEPCO	LA	2025	14-years	0.6	9.0
Eversource	CT	proposed	15-years	0.6	9.6
Duke Energy Progress	SC	2025	20-years	0.6	12.4
CLECO	LA	2022	9-20 years	0.5	8.5
Duke Energy Carolinas	TX	proposed	long-term	0.5	0.6
National Grid	MA	2025	5-years	0.4	2.0
Duke Energy Progress	NC	2025	20-years	0.4	7.5
Green Mountain Power	VT	2025	1-year	0.4	0.4
Centerpoint	TX	2025	15-years	0.3	3.8
Georgia Power	GA	proposed	4-years	0.3	1.0
Entergy Texas	TX	2022	15-years	0.2	3.4
Rochester Gas & Electric	NY	2025	10-years	0.2	2.0
Duke Energy Carolinas	NC	2025	20-years	0.2	3.8
PPL Electric	PA	2025	1-year	0.2	0.2
PSE&G	NJ	2025	long-term	0.2	0.4
AEP Texas	TX	2019	5-15 years	0.1	1.4
Portland General Electric	OR	2023	7-years	0.1	0.8

Source: LBNL • Created with Datawrapper

- **Proactive** investments: storms and **wildfires**
  - Investments and insurance to reduce impacts
  - Wildfires are largest driver in CA: > 4 ¢/kWh
  - **Growing price impacts in western states**

Recent Estimates of Utility Wildfire Mitigation Costs

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 but some also include liability insurance. Data should only be used to illustrate wide range of and significant impacts.

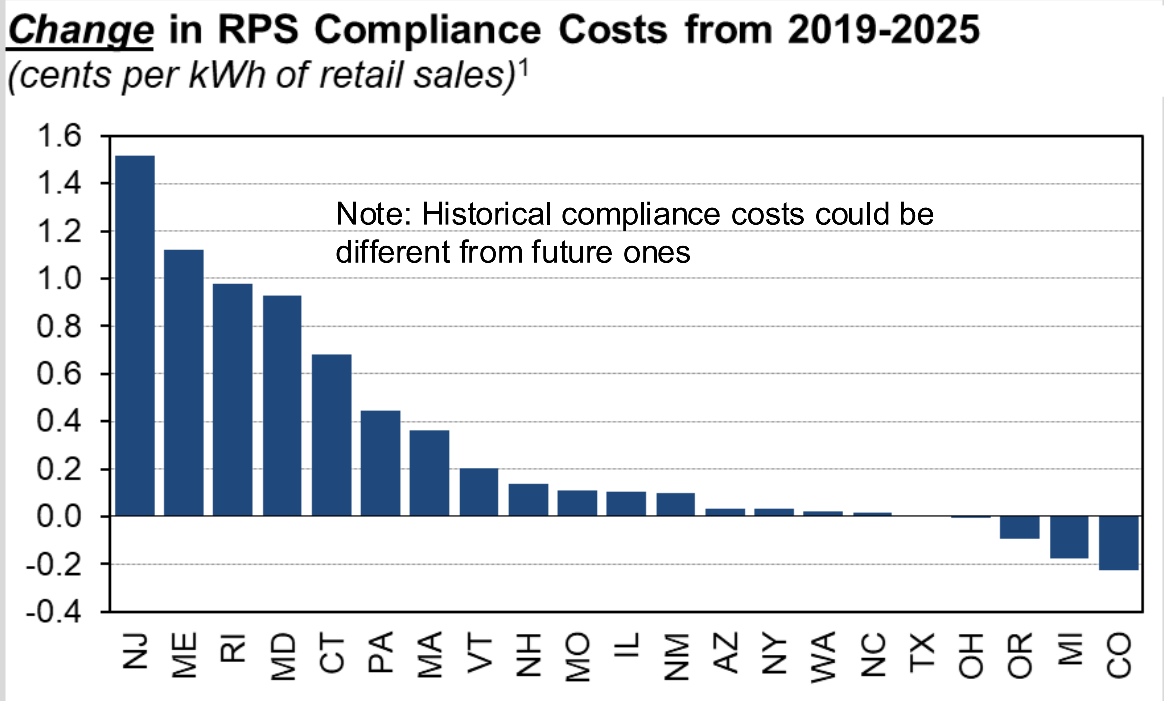
Utility	State	Equivalent impact (cents/kWh)	Scope
PG&E	CA	5.0	actual price: mitigation & liability
SDG&E	CA	4.7	actual price: mitigation & liability
SCE	CA	3.3	actual price: mitigation & liability
KIUC	HI	1.7	proposed cost: mitigation
Hawaii Electric	HI	1.5	proposed cost: mitigation
PSCo	CO	1.5	estimated 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

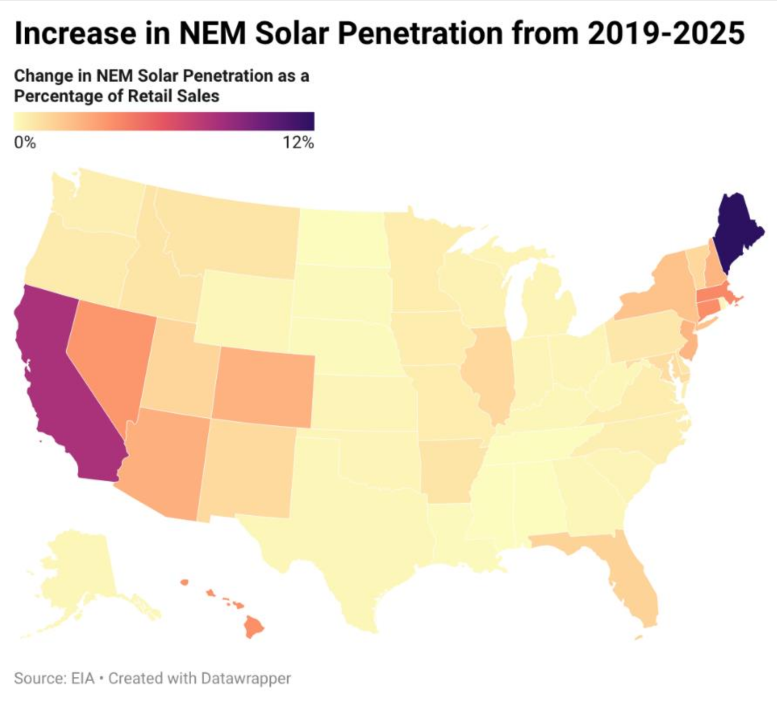
Source: LBNL • Created with Datawrapper

Source: Review of available data from 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

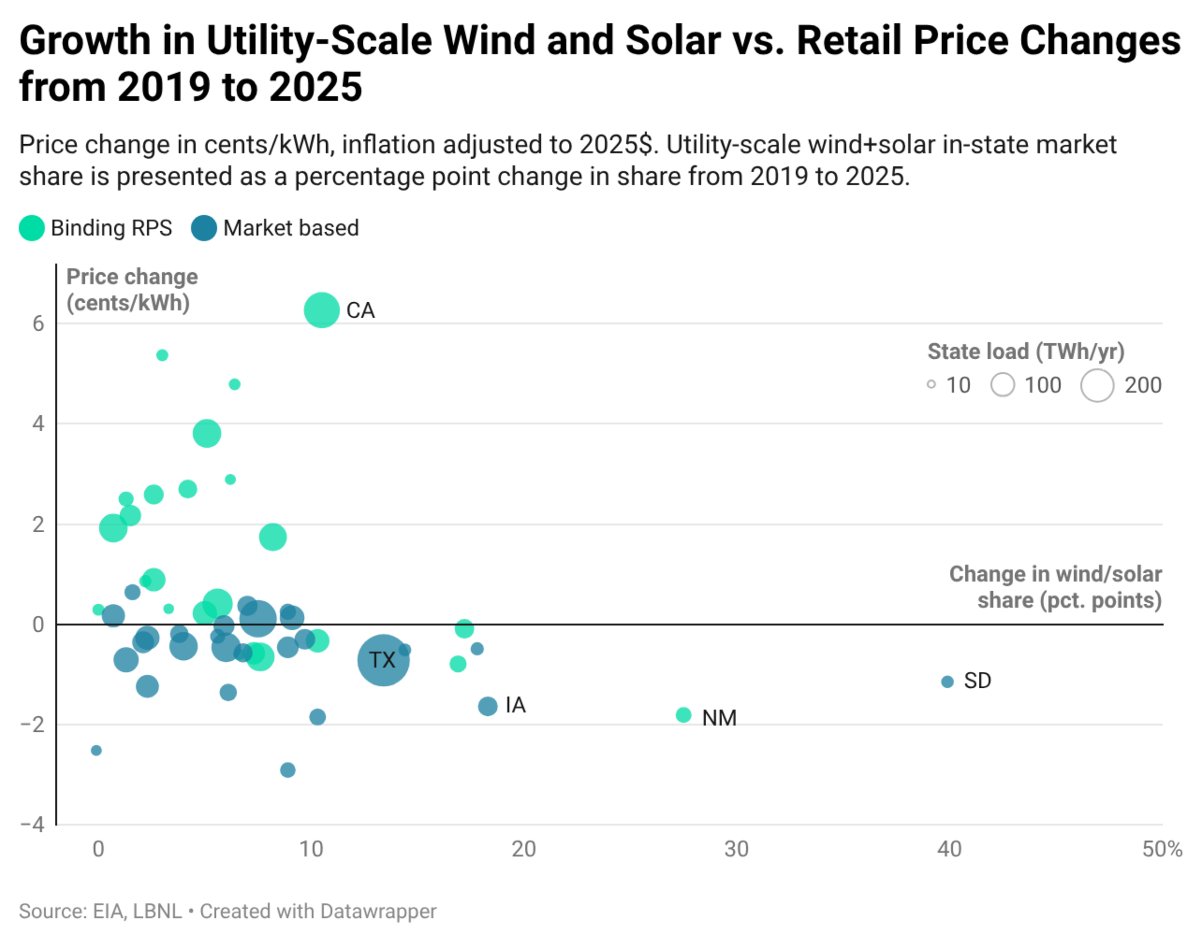
- **RPS:** Compliance costs from 2019-2025 equate to an average price increase of ~0.25 ¢/kWh; in some mid-Atlantic and New England states >1 ¢/kWh; earlier statistical analysis supports impacts of this magnitude
- **Net metering:** Results in fixed costs being spread over lower sales; statistical analysis and other studies suggest impacts <0.5 ¢/kWh in 40 states, but as high as ~2 ¢/kWh in California





State RPS policies often increased prices but “market based” wind & solar, supported by tax incentives, do not appear to have increased retail prices

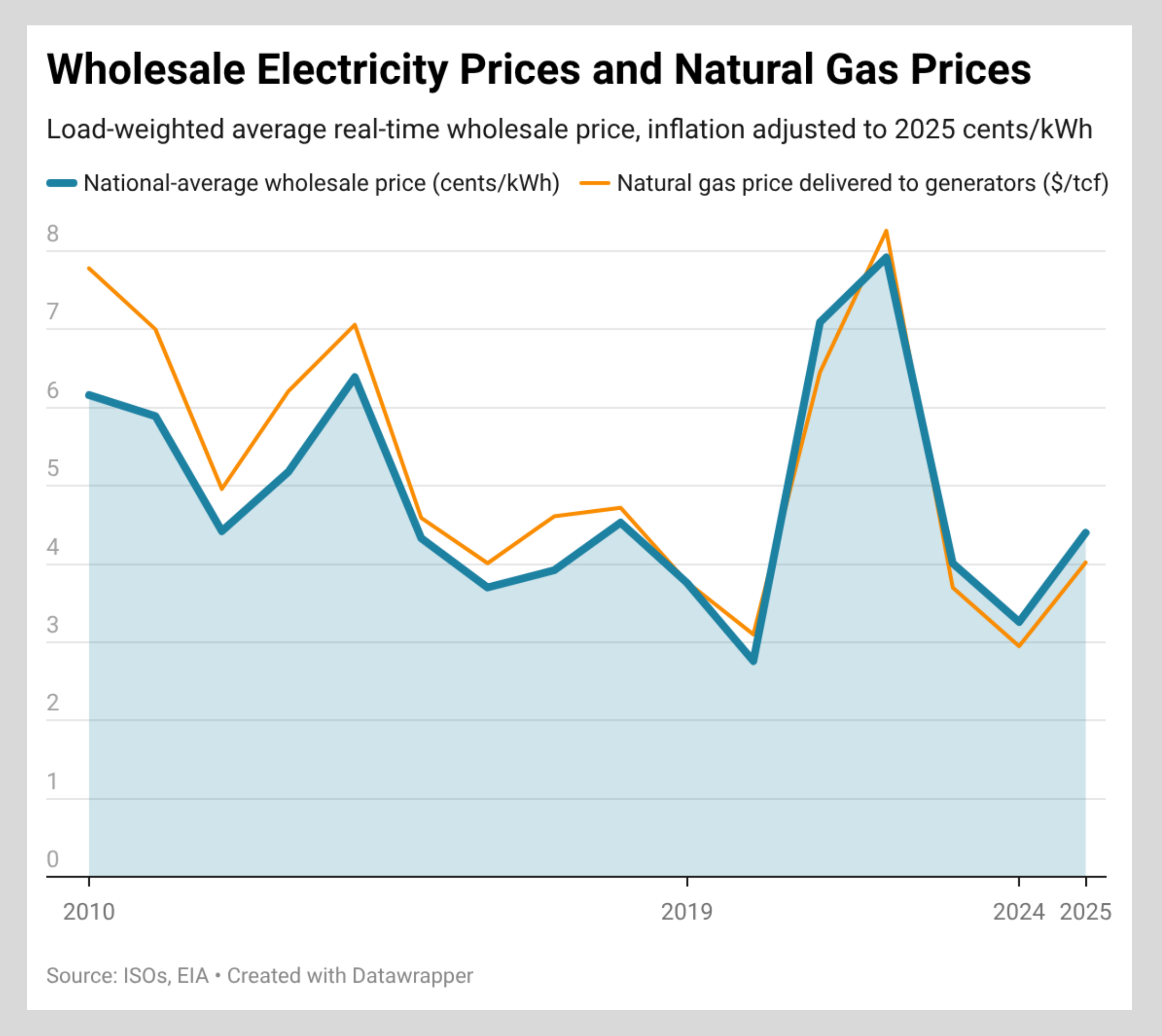
- Growth in utility-scale wind and solar also occurred outside of RPS policies, supported by tax incentives but not compelled by RPS programs
- No obvious correlation between higher price increases and “market based” deployment of wind and solar over this period (as shown in blue circles in figure)
- Statistical analysis supports graphical relationships: binding RPS generally increased prices, especially in 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; statistical analysis was used to isolate drivers, and produced results consistent with general observed trends

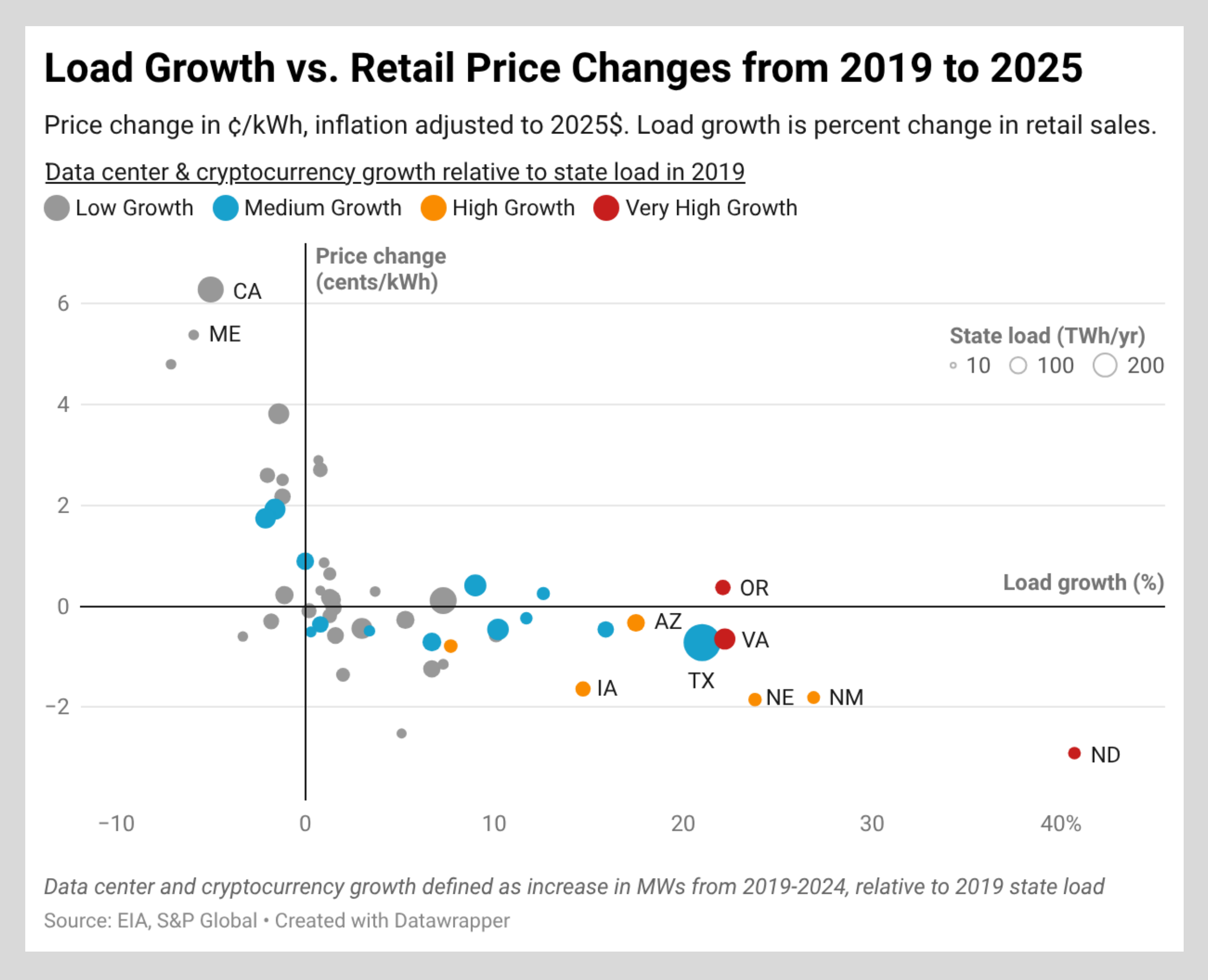
Low-cost natural gas has reduced retail electricity prices over the long term; gas price fluctuations impact year-to-year variation in electric prices

- Declining inflation-adjusted natural gas prices contributed to large reductions in generation costs over the long term
- Natural gas accounts for a large share of generation, reflecting its economic competitiveness
- However, gas prices are variable, and pass through to wholesale and retail electricity prices
- Example: onset of Ukraine/Russia war increased retail prices by 2 ¢/kWh in some states and > 4 ¢/kWh in New England, with subsequent decline
- Gas price increases in 2025 vs. 2024 significantly increased wholesale prices in ISO-NE, NYISO, PJM, MISO



Load growth at the state level has (historically) tended to depress retail electricity prices…*unclear to what degree this will hold in the future*

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



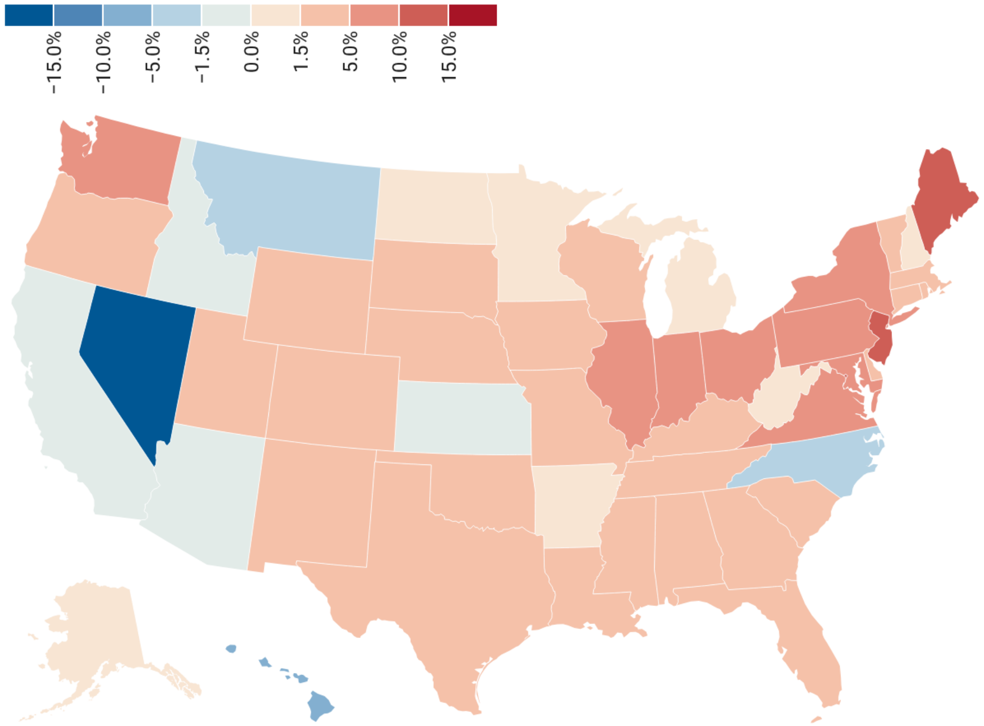
2025 & beyond – *What's coming down the pike*

Retail price increases over the last year have outpaced inflation nationally and in a growing number of states

Prominent drivers for YoY price increases: fuel and wholesale power prices; inflation & hardening of distribution assets; capacity prices; transmission costs; storm recovery costs

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

Percentage change, adjusted for inflation in 2025$

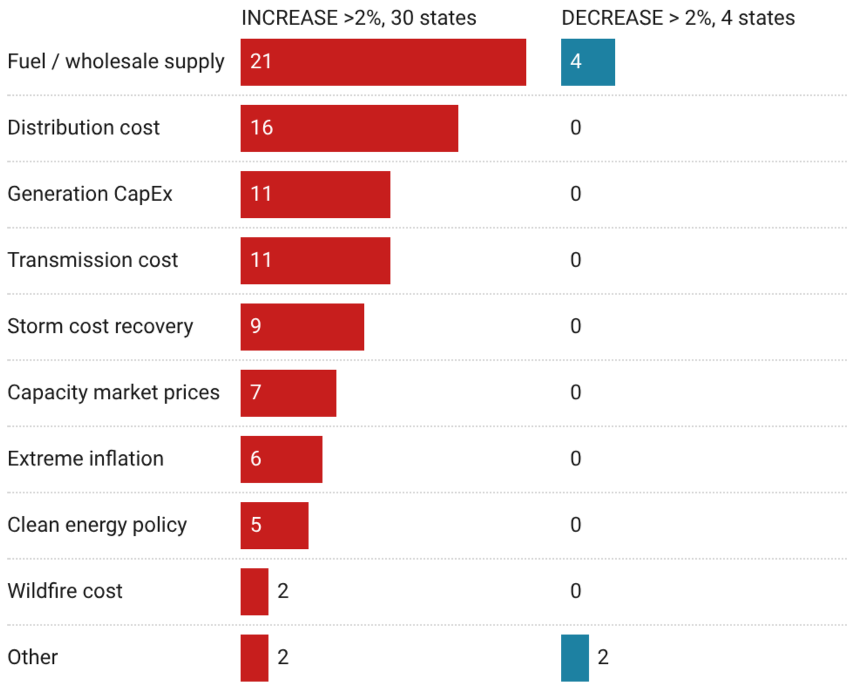


Source: EIA • Created with Datawrapper

Data for 2025 are through November

Primary Drivers of Price Changes: 2024 to 2025

Stated reasons for price changes from 2024 to 2025 for those states with price increases or decreases of greater than 2%, after adjusting for inflation



Source: LBNL • Created with Datawrapper

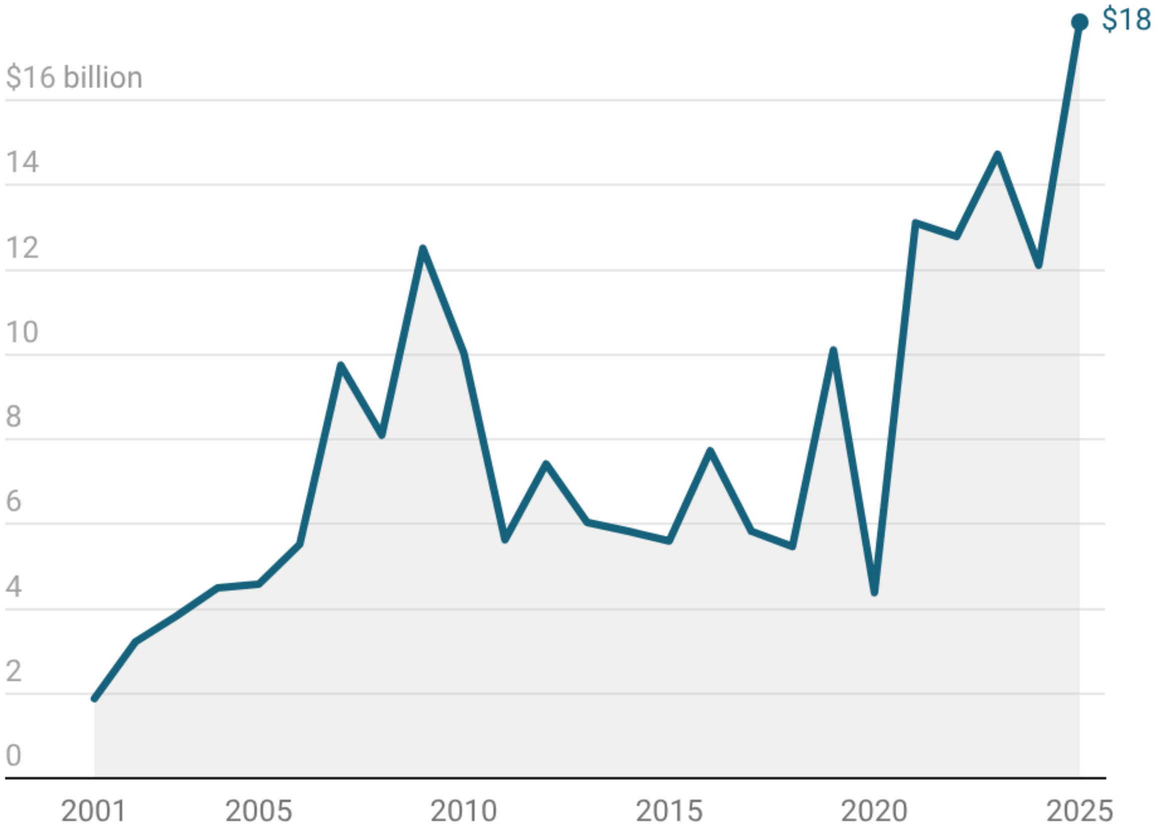
The few states that experienced larger reductions in inflation-adjusted prices did so via lower fuel prices (sometimes from delayed reductions after increase from Ukraine-Russia war).

Note: year-over-year trends are subject to various state ratemaking idiosyncrasies; trends and drivers reported here are therefore, to a degree, unstable.

IOU rate increase requests in 2025 higher than experienced in decades and PUC acceptance has been high → suggests continued price increases

Investor-Owned Utility Rate Change Requests

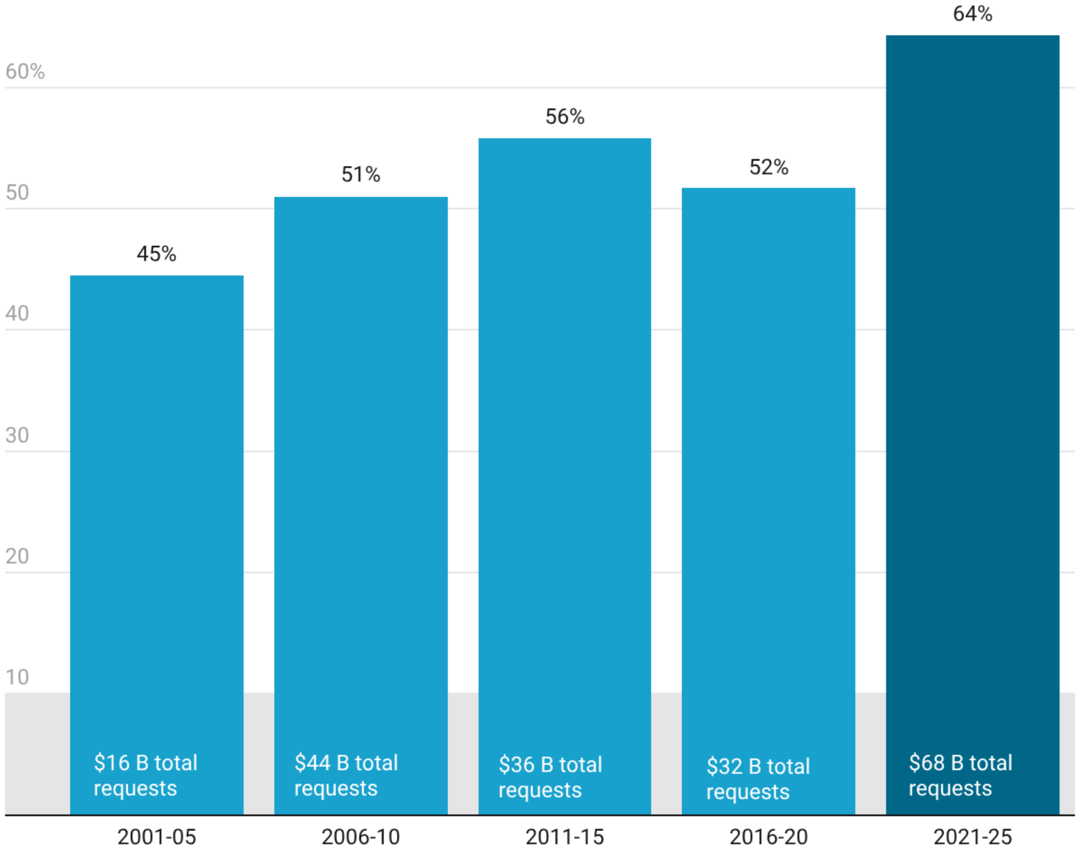
Billion $, inflation-adjusted to 2025



Source: S&P Global • Created with Datawrapper

Regulatory Approval Levels for IOU Rate Increase Requests

Approvals as a percent of rate 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

<u>Notes:</u> (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 limited issue rider cases. Fuel cost changes and rate riders not fully captured.

Policy options

Reducing Retail Prices: A Menu of Many Options

STRATEGIC POLICY & REGULATORY LEVERS

Overarching policy

- Public benefits cost allocation: rates vs. taxes
- Reassessment of policy decisions impacting prices
- Integrated proactive planning under uncertainty
- Consumer information and transparency

Regulatory model for IOUs

- Performance-based regulation
- Multi-year rate plans, revisions to riders, CWIP, etc.
- Return on equity and financing determinations

Transmission and distribution

- Enhanced scrutiny of costs and cost/benefit tradeoffs
- Getting the most out of the existing system: GETs, load flexibility, EE
- Securitization / public finance of new investments
- Grow the equipment supply chain

Generation supply

- Get the most out of the existing system: GETs, load flexibility, EE
- Relieve constraints on new build: interconnection, permitting, market design

Cost allocation

- C&I vs. residential rates
- Large load tariffs, demand flexibility, bring your own generation
- Low-income bill assistance

LAWRENCE BERKELEY NATIONAL LABORATORY

Brattle

For more information

This Overall Project Currently Includes Multiple Products

For more information, contact: Ryan Wiser (rhwiser@lbl.gov)

Peer-reviewed journal article	Data visualization tool	Detailed presentations
Highlights a subset of the trends, with a focus on statistical analysis of broad drivers	Allows users to explore some of the data that underpins the journal article	Summarizes the article and provides additional material beyond that included here

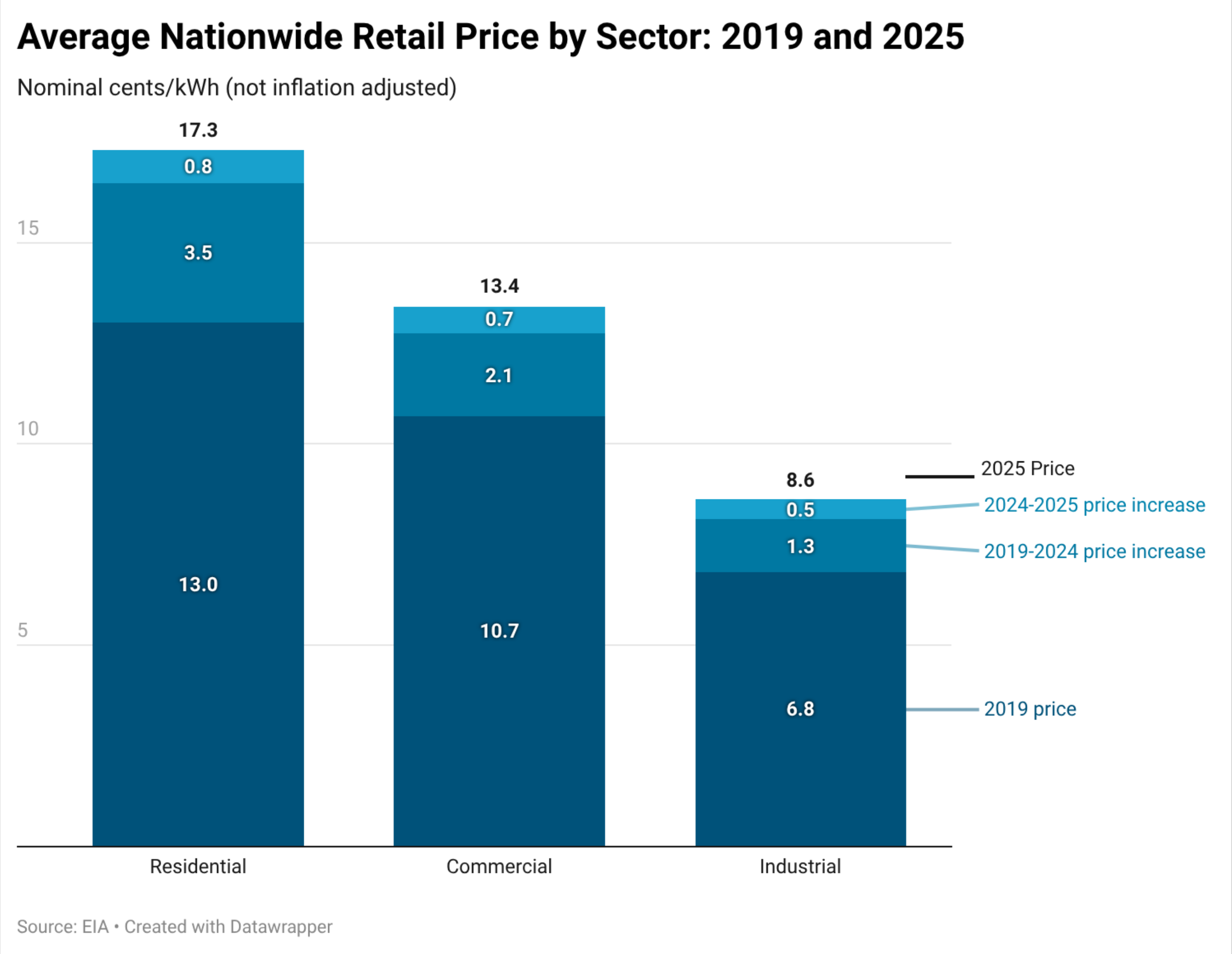
These products can all be found at: https://eta-publications.lbl.gov/publications/factors-influencing-recent-trends

Acknowledgements:
This work was funded by the U.S. Department of Energy's Office of Critical Minerals and Energy Innovation under Contract No. DE-AC02-05CH11231.

Appendix

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

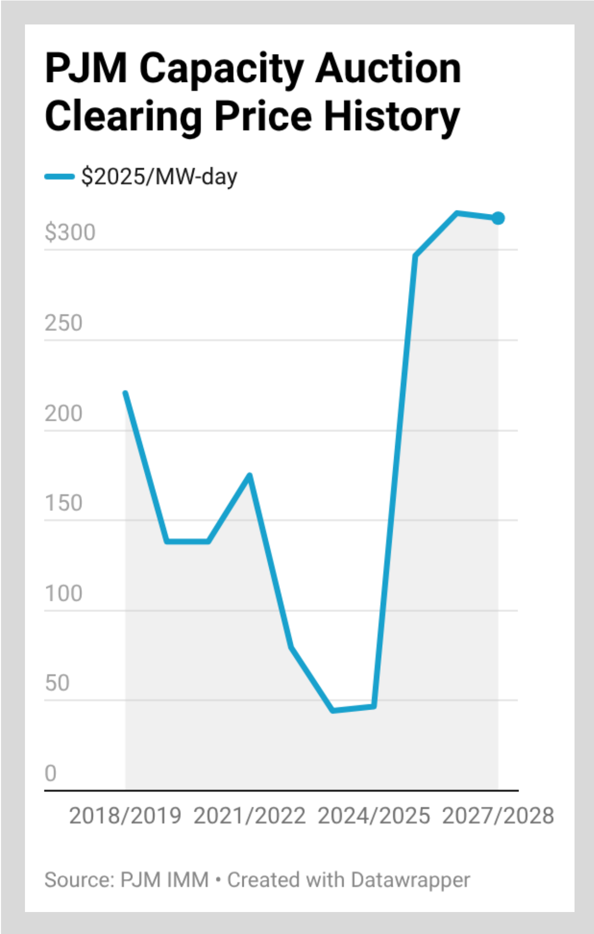
- Residential prices are higher and have risen faster than C&I
- From 2019 to 2025 (nominal):
  - Residential up: 33%
  - Commercial up: 26%
  - Industrial up: 27%
- Continues a longer-term trend of increasing gap between residential and C&I prices
- However, from 2024 to 2025:
  - Residential up: 5.0%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



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

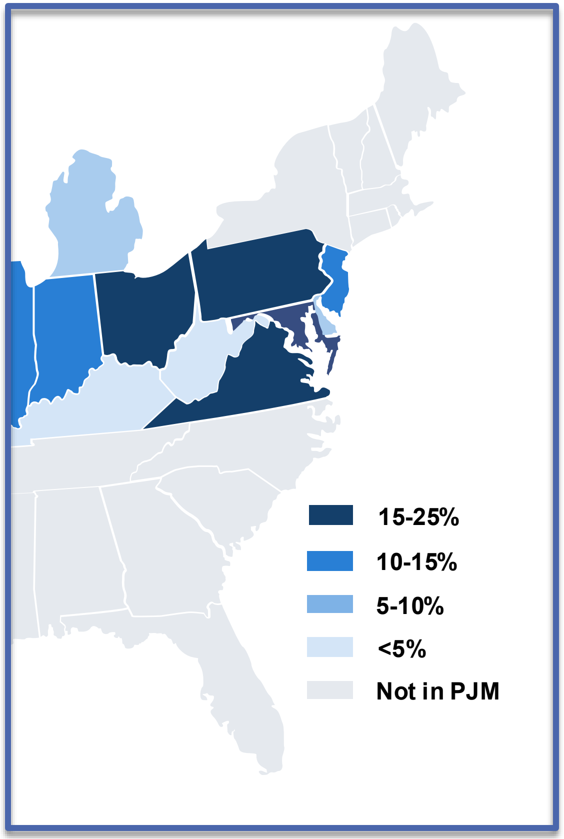
Capacity prices are one but not the only contributor to retail price increases

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. One can therefore also interpret the rapid increase in clearing prices as indicative of prices that were 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 Retail Prices Between Nov 2024 to Nov 2025



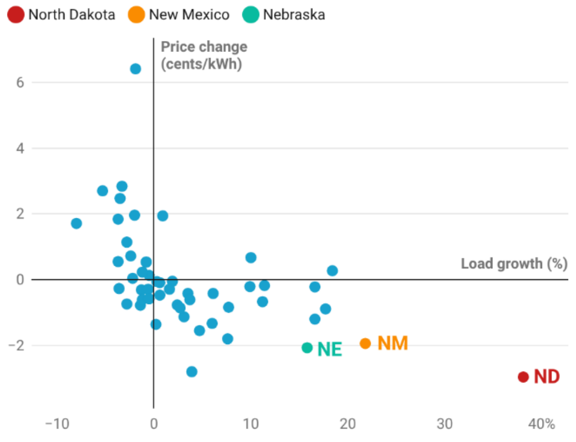
Notes and source: States with vertically integrated utilities are shielded to some extent from capacity auction price spikes because utilities can self-supply instead of purchasing capacity from PJM: from EIA Electricity Monthly Update Sept. 2025

Case Study: North Dakota, New Mexico & Nebraska demonstrate ability to lower prices

Managing load growth while reducing inflation-adjusted retail prices

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

Load Growth vs. Price Change: 2019-2024

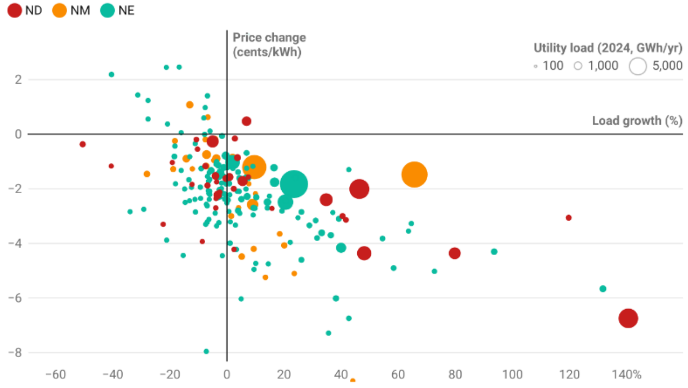


Source: EIA • Created with Datawrapper

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 from 2019-2024: North Dakota, New Mexico, Nebraska

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- and Sector- Specific Load Growth on Retail Price Changes from 2019-2024

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

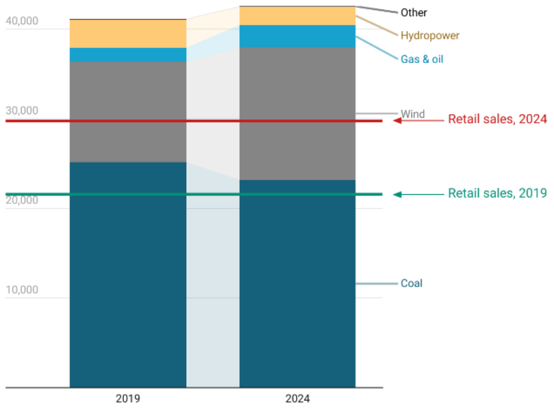
Utility Grouping	Residential Load Growth	Residential Price Change	C&I Load Growth	C&I Price Change
High Load Growth: >20%	−1%	-1.3	64%	-2.7
Low Load Growth: 0-20%	4%	-1.3	10%	-1.4
Load Contraction: shrinking	−2%	-0.9	−10%	-0.9

Source: EIA • Created with Datawrapper

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

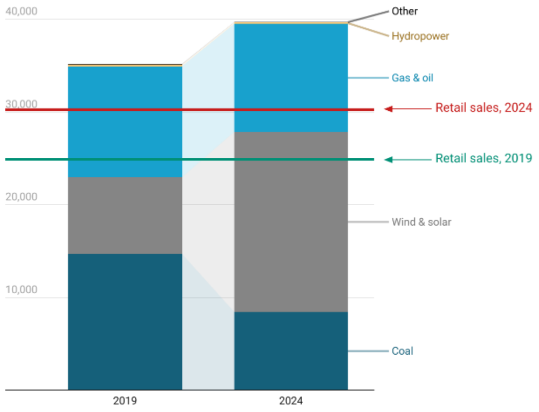
- Substantial C&I growth enabled fixed costs to be spread over more load
- Abundant, low-cost energy enabled load to be served at low incremental cost

North Dakota Generation and Retail Sales (GWh)



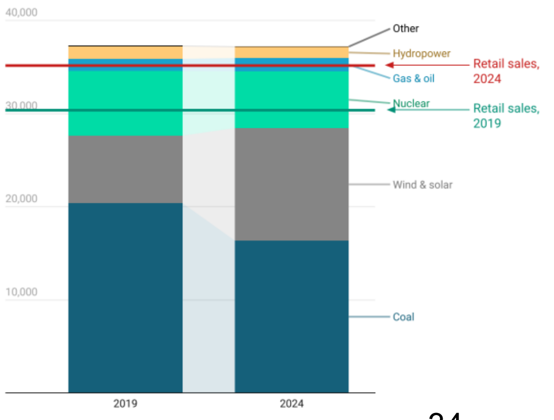
Source: EIA • Created with Datawrapper

New Mexico Generation and Retail Sales (GWh)



Source: EIA • Created with Datawrapper

Nebraska Generation and Retail Sales (GWh)



Source: EIA • Created with Datawrapper

Illinois Pricing, Recent Trends, and State Tools

Nathan Miller
Senior Director, Energy + Environmental Economics, Inc.

CONTENTS

Three Major Components of Electricity Bills for Illinois Consumers

Supply

- **Generation →** cost to produce electricity from power plants on the grid, inclusive of market prices and owned or contracted power supply.
- **Transmission →** cost to deliver electricity from power plants on the grid to the utility's distribution network.

Delivery

- **Distribution →** cost to deliver electricity from the transmission network to the customer's location on the local utility's distribution network.

Taxes + Programs

- **Taxes →** state and local taxes
- **Programs →** ratepayer-funded costs of utility energy efficiency programs, behind the meter solar programs, and state renewable energy procurements.

Supply Costs are Driven by Market Prices and Managed by Different Suppliers through Contracts and/or Owned Power Plants

Supply

- All suppliers pay market prices for supply from regional grids (MISO and PJM):
  - Energy market prices by hour (or every 5 min) for each location in Illinois
  - Capacity prices by year as determined by MISO and PJM capacity markets
  - Ancillary services for grid balancing and operations
- Suppliers can choose to manage the cost of supply by owning or contracting with power generators
- Transmission charges are based on rates regulated by FERC

Default Service

comed AN EXELON COMPANY | Ameren | MIDAMERICAN ENERGY COMPANY

The IPA buys and hedges wholesale power for default service customers in ComEd, Ameren, and MidAmerican service territories.

IPA ILLINOIS POWER AGENCY

Alternative Retail Electric Service (ARES)

ARES buy wholesale power and manage supply cost through owned power plants, contracts with power generators, and financial hedges.

Municipal Utilities & Electric Cooperatives

Municipal utilities and electric cooperatives typically buy power under contracts with an ARES provider and / or generate from their own power plants, along with wholesale market purchases.

Delivery Costs are Driven by Regulated Rates under a Cost-of-Service Structure for All Customers in IOU Service Territories

Delivery

What drives distribution rates?

- Capital investment, including grid modernization and replacement
- Cost of financing
- Operations and maintenance
- Metering, billing, and other general and administrative expenses

Default Service + ARES (IOU Service Territories)

The ICC regulates the delivery network rates for customers located within the ComEd, Ameren, and MidAmerican service territories in Illinois.

Rates are set by a cost-of-service framework and determined through multi-year rate cases every four years.

Municipal Utilities & Electric Cooperatives

Municipal utilities and electric cooperatives own their own distribution networks and make their own rates for their customers. These providers are not regulated by the ICC.

Taxes and Programs Fund State Priorities for Renewable Energy, Customer Solar, Energy Efficiency, and Community Assistance

Taxes and Programs

- What types of program fees are listed?
  - Renewable energy programs, including customer solar programs and renewable energy purchases
  - Energy efficiency programs
  - Energy transition assistance—CEJA workforce and community programs
  - Environmental mitigation costs
- What taxes are listed?
  - State taxes
  - Municipal taxes

Default Service + ARES (IOU Service Territories)

The costs of renewable energy purchases for utility-scale wind and solar and behind-the-meter customer solar are all paid for by collections from customers in the Investor-Owned Utility (IOU) service territories in Illinois.

Similarly, ratepayer-funded programs such as energy efficiency incentives are also paid for by separate charges on customer bills.

Local electricity taxes vary by city in Illinois.

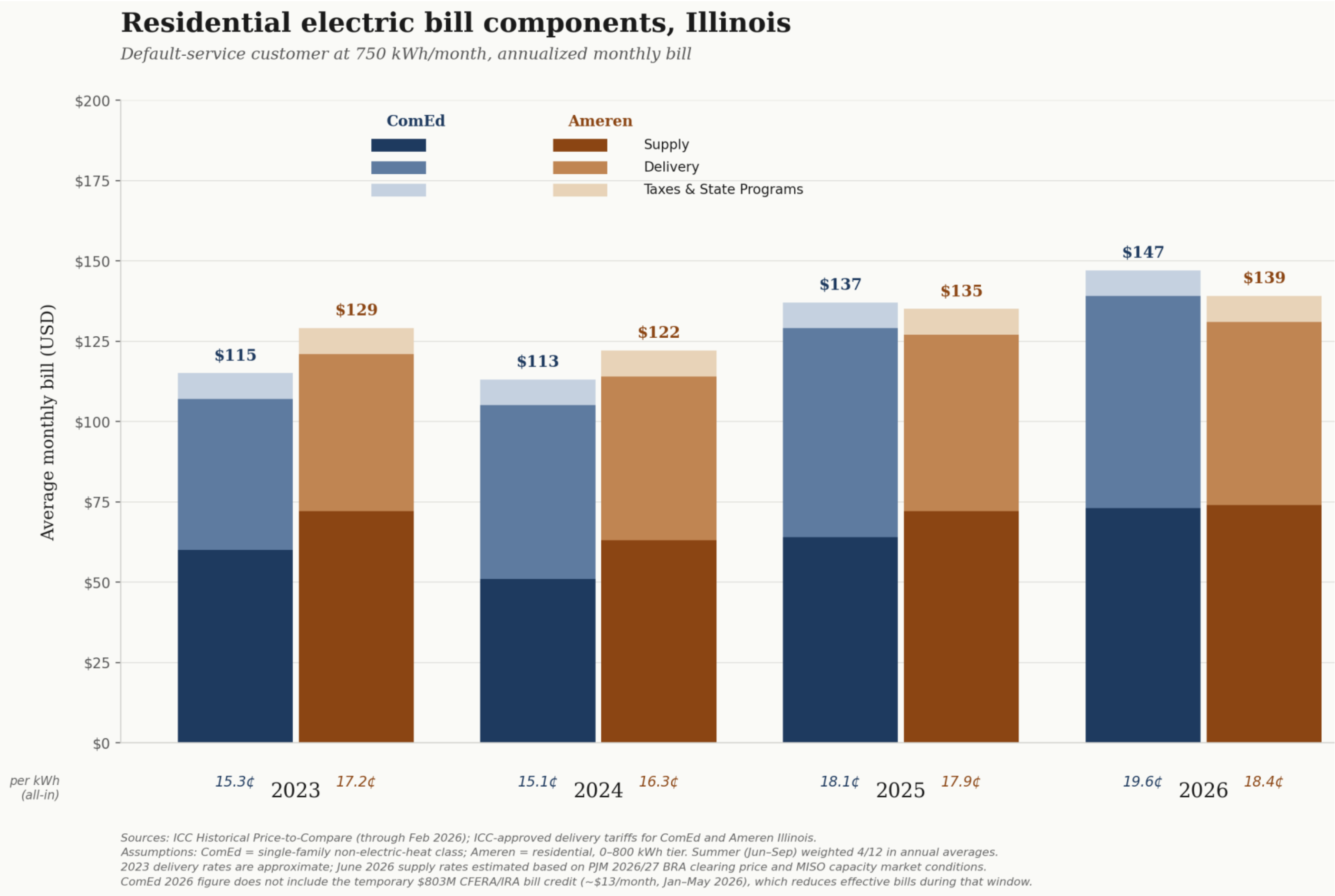
Municipal Utilities & Electric Cooperatives

Municipal utilities and electric cooperatives are not regulated by the ICC and are exempt from major state programs, including the RPS and energy efficiency programs.

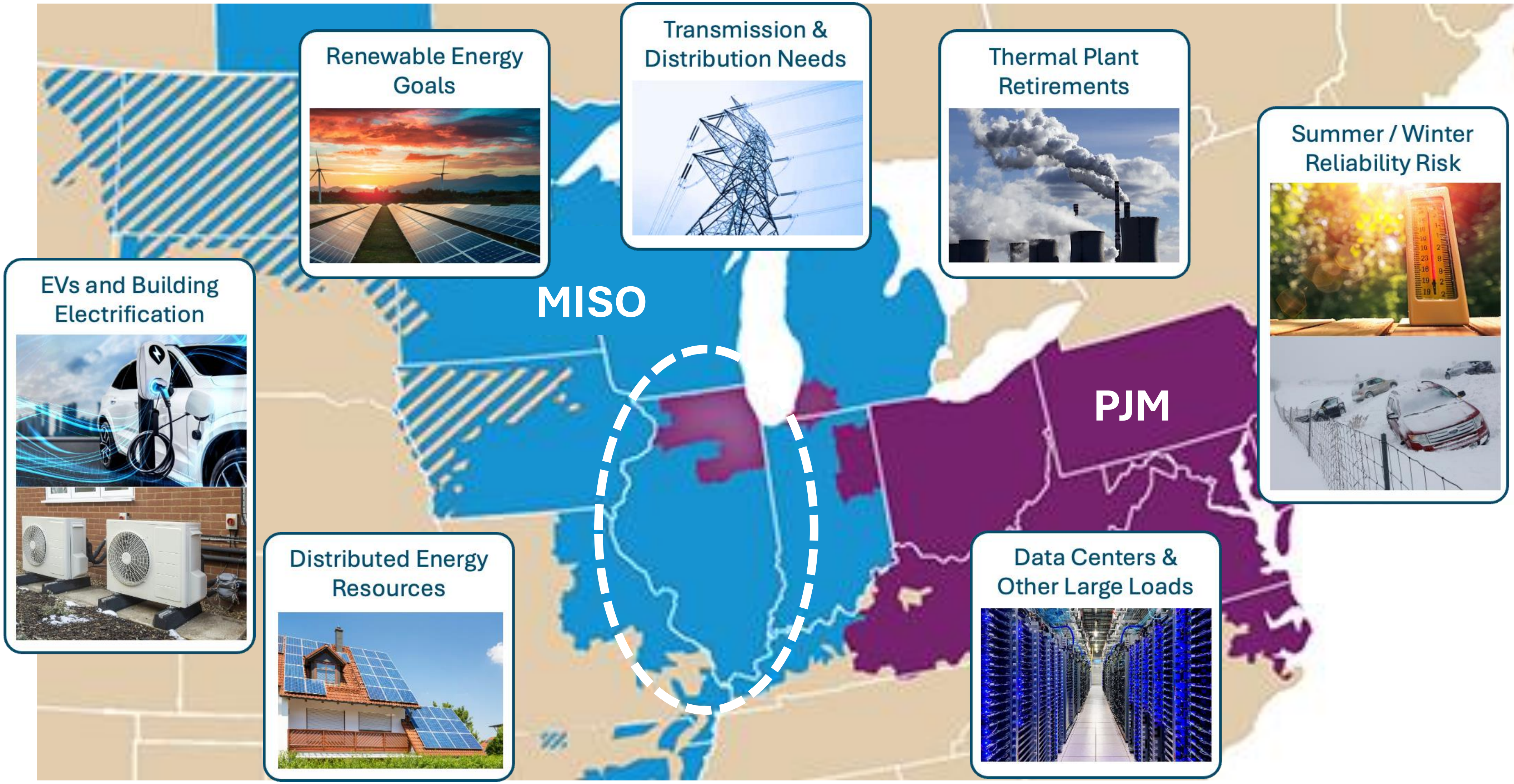
These providers may set up their own programs and charges at their discretion.

Illustrative Monthly Bills for Residential Customers 2023-2026

- *Illustrative monthly bills* for a non-electric heat residential customer using 750 kWh per month averaged over the year
- Supply charges are ~50% of total monthly bill
  - Supply charges fell from 2023 to 2024 with natural gas prices
  - Supply charges are increasing in 2025 and 2026 with capacity market prices in PJM and MISO
- Delivery charges have been steady in Ameren but increasing in ComEd
- Taxes and state program fees vary by customer location but are small costs on bills today

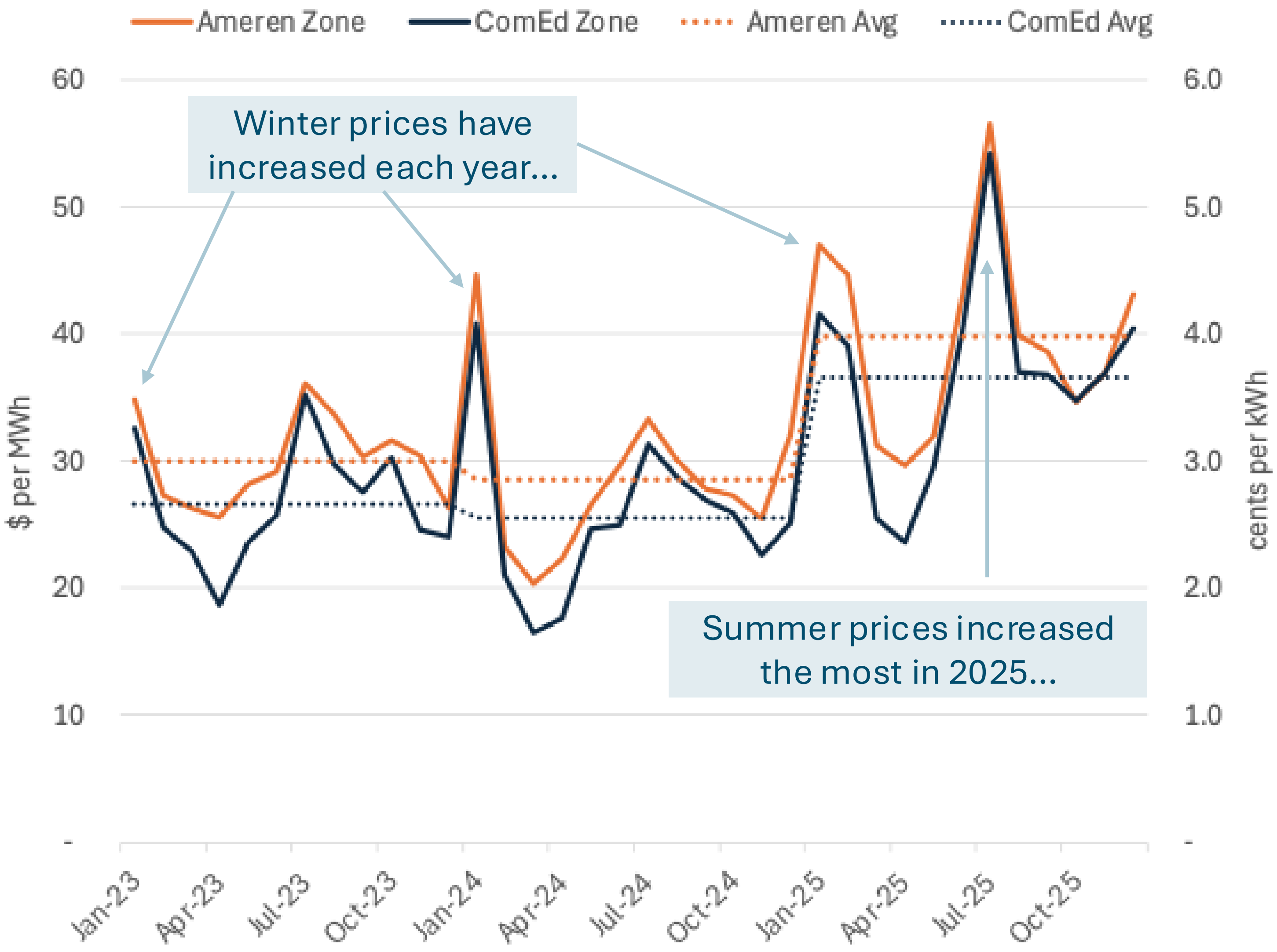


Big Picture: Illinois is Right in the Middle of the Changes and Challenges in the U.S. Electricity Sector



What is Driving Supply Costs in Illinois?
Let's Talk about Energy Prices…

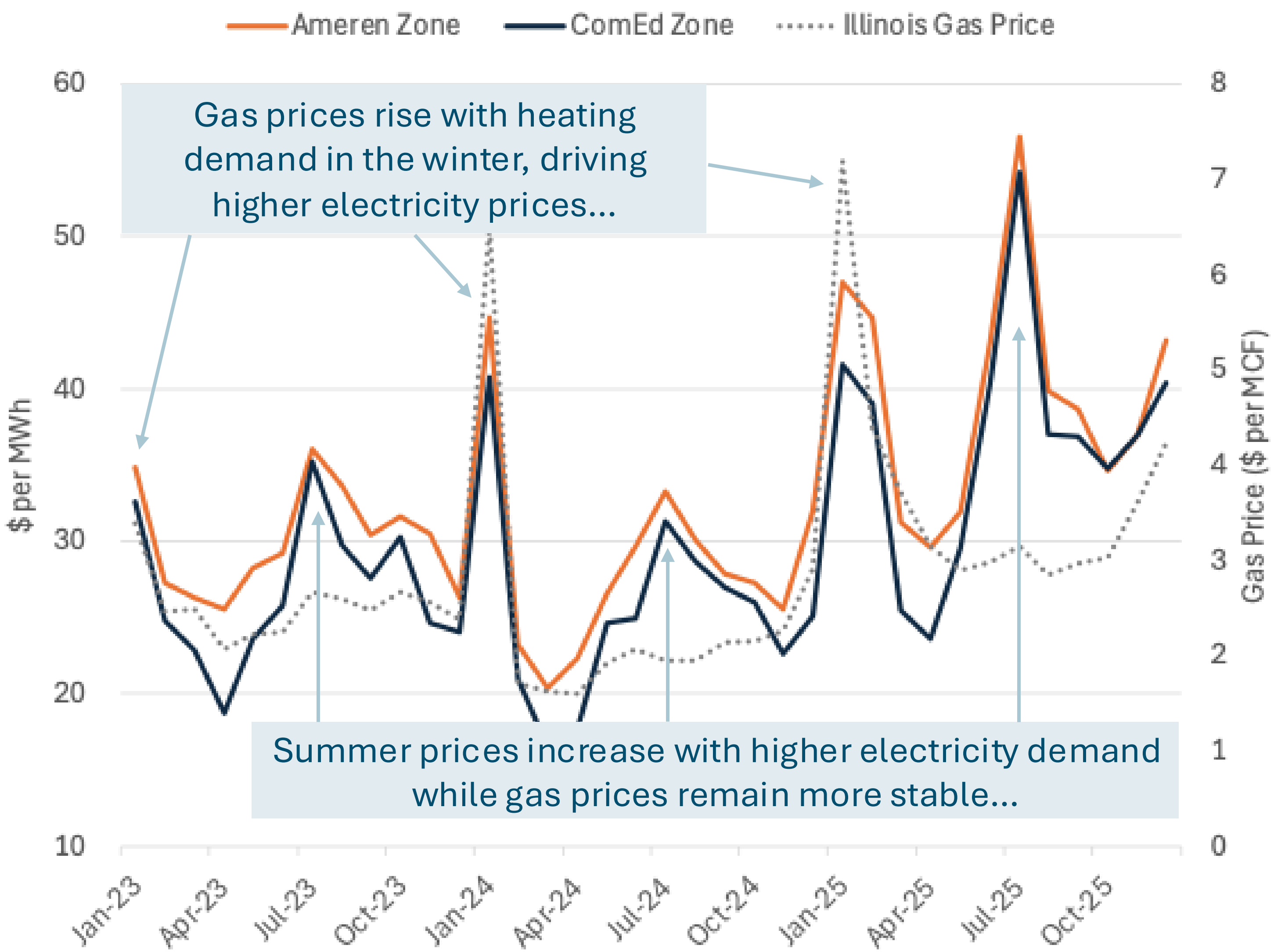
- Energy prices are determined in the MISO and PJM regional markets for the Ameren and ComEd Illinois zones
- Prices in both Illinois zones tend to move together: annual average prices in the MISO Ameren zone typically ~$3 per MWh higher than the PJM ComEd zone over the past three years
- Energy prices were similar from 2023 to 2024…but *2025 saw an increase of ~$10 per MWh, a 35-40% increase from the previous two-year average*.



Source: Day-Ahead Hourly Energy Prices for the MISO Ameren Zone and PJM ComEd Zone. Monthly and annual averages are not load-weighted.

What is Driving Supply Costs in Illinois? Let's Talk about Energy Prices…

- Energy prices are driven by the short run marginal cost from the most expensive plant needed to serve demand in any given hour…
  - In most hours, this is the fuel and variable O&M cost of a natural gas-fired power plant
  - Power plant heat rates (fuel efficiency) and gas prices are the biggest drivers of this cost
  - High demand hours tend to have higher prices because the cheapest plants are already generating, leaving higher-cost power plants to deliver remaining needs
- Energy prices in 2025 increased because of *both natural gas prices and higher summer demand*.

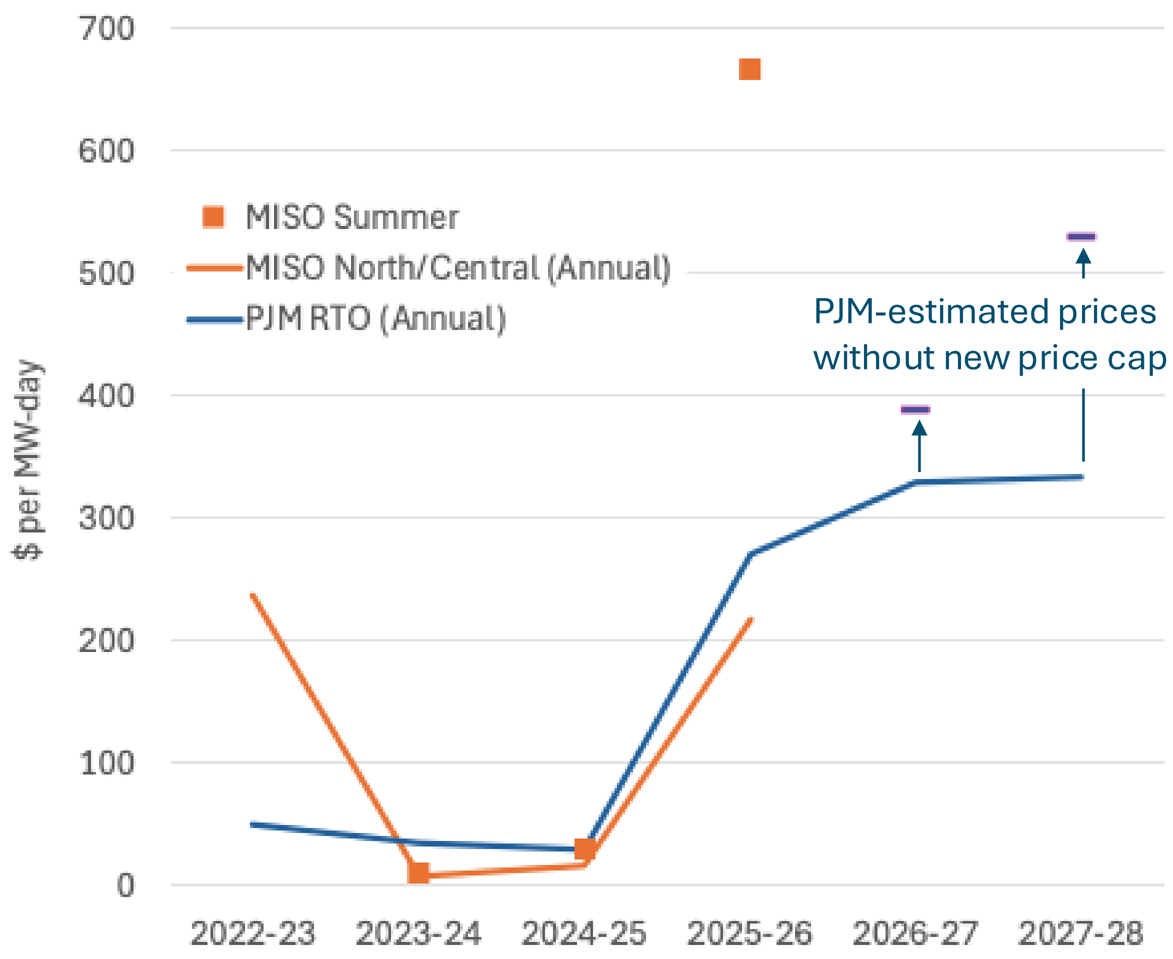


Source: Day-Ahead Hourly Energy Prices for the MISO Ameren Zone and PJM ComEd Zone. Monthly and annual averages are not load-weighted.

What is Driving Supply Costs in Illinois? Let's Talk about Capacity Prices…

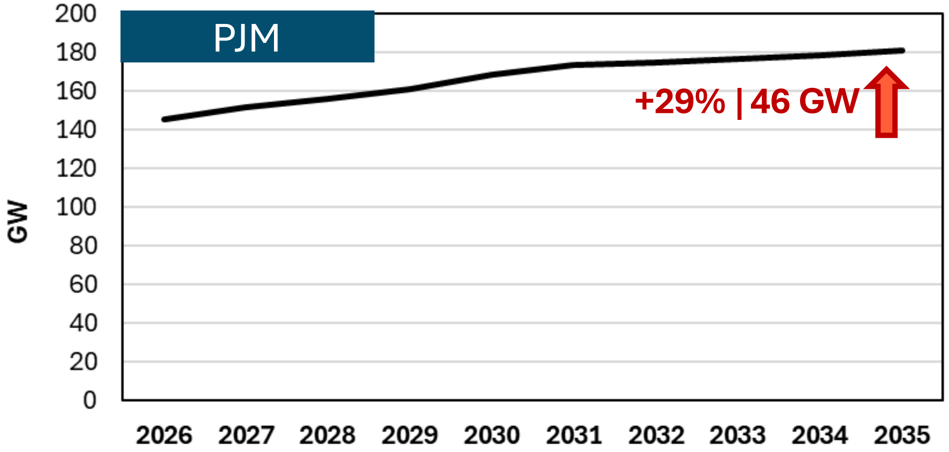
- MISO and PJM operate capacity markets to pay resources for their contributions to system reliability
- Generators contribute to reliability based on their expected availability to produce electricity during "critical hours" when there is a risk the grid may not have enough energy to meet demand
- Customers pay for these resources based on their share of the system's reliability need (in MW) at the price of capacity from MISO and PJM auctions
- Last year, Illinois state agencies (ICC, IPA, and IEPA) completed the first Resource Adequacy Study (published December 2025) directed by CEJA
  - RA Study analyzed reliability challenges facing Illinois and the broader connected regions of MISO and PJM
  - RA Study concluded that reliability risks will continue to affect Illinois and both regions, requiring solutions

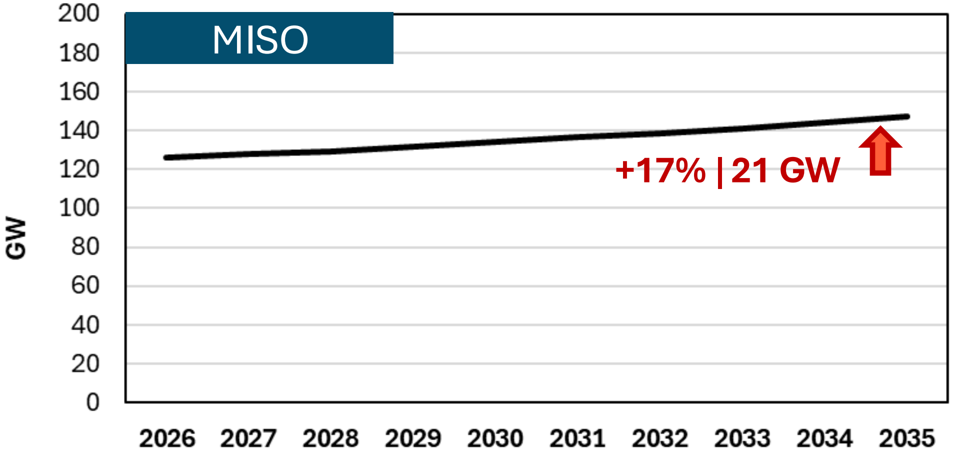
PJM and MISO Capacity Prices by Delivery Year

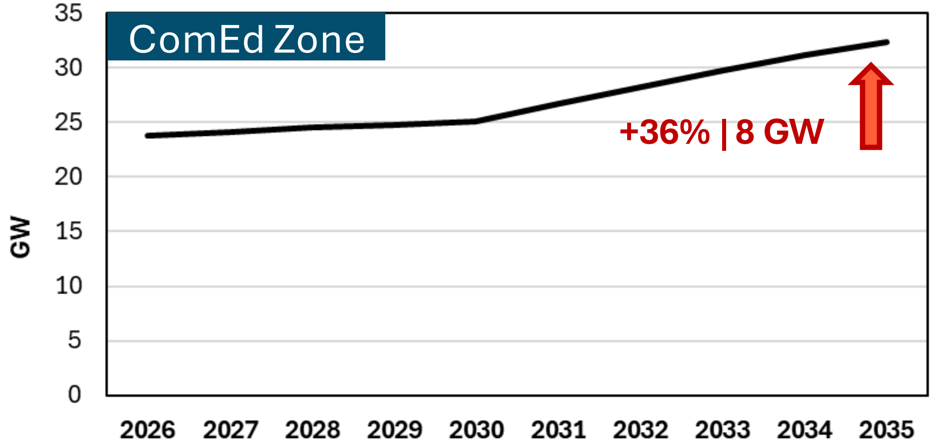


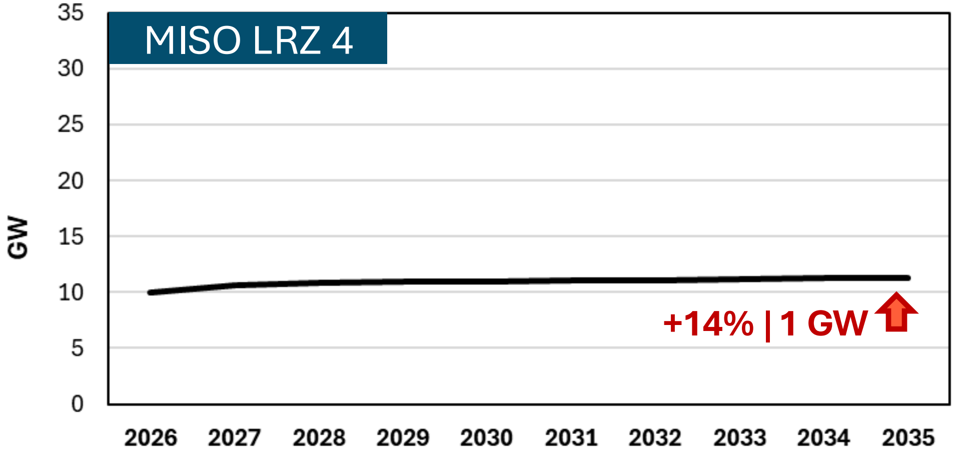
RA Study: Peak Demand is Growing in Illinois and RTO Regions

Both PJM and MISO project significant load growth in the next 10 years, which is also reflected within Illinois zones.





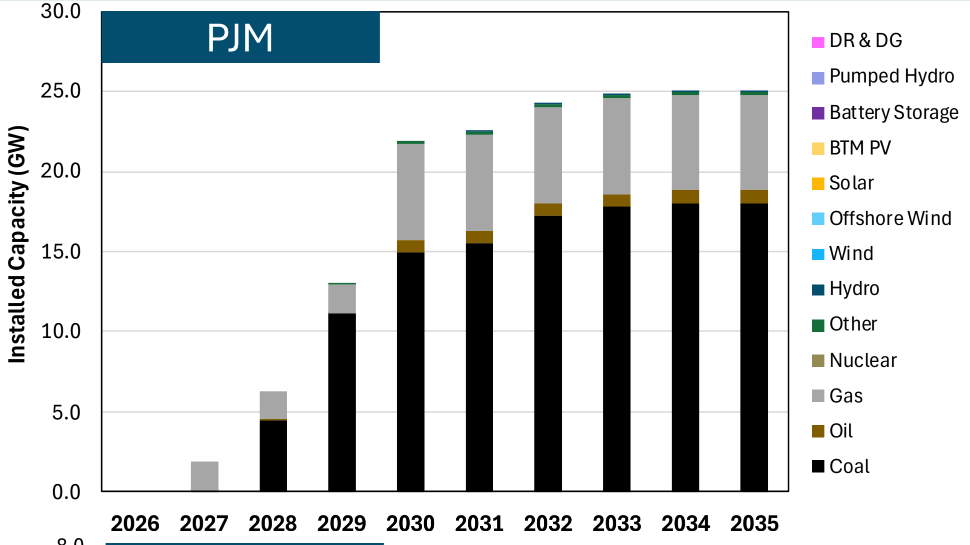


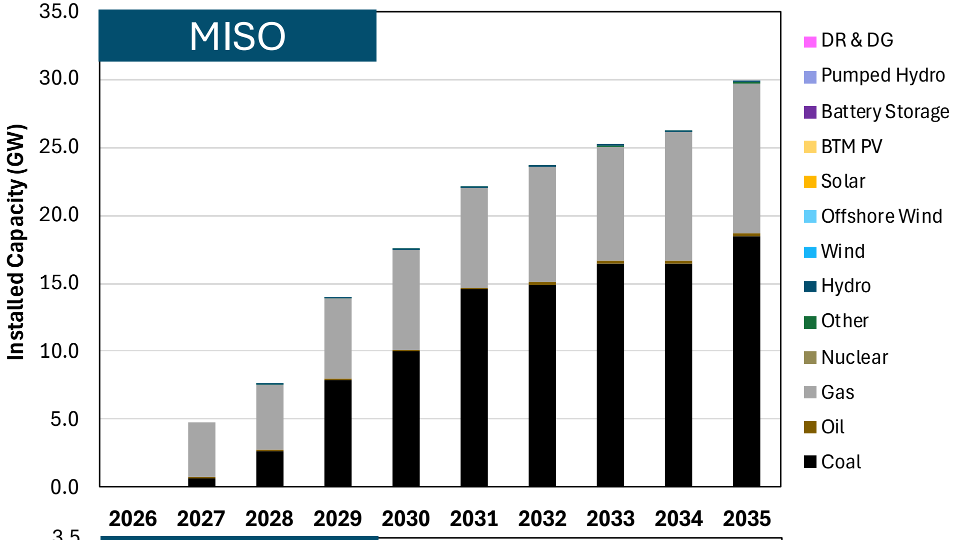


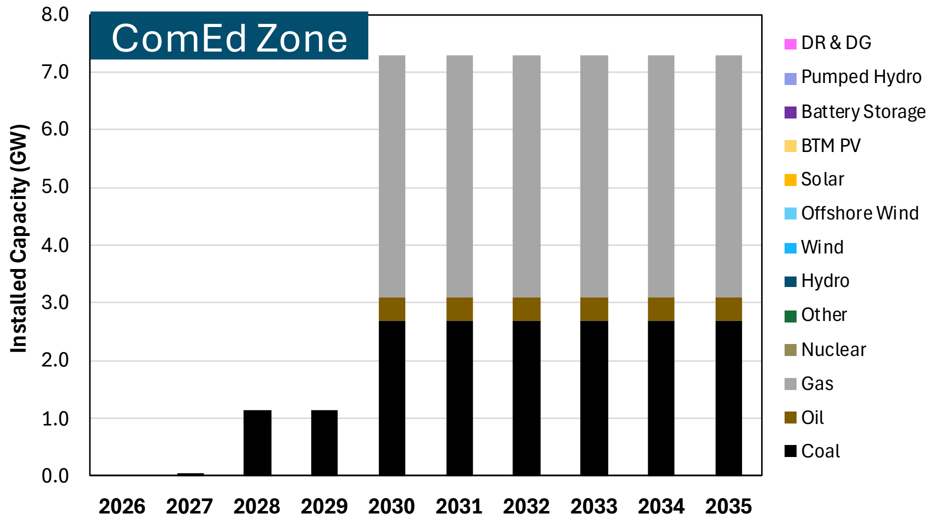
Sources: ComEd & Ameren utility load forecasts; RTO published load forecasts

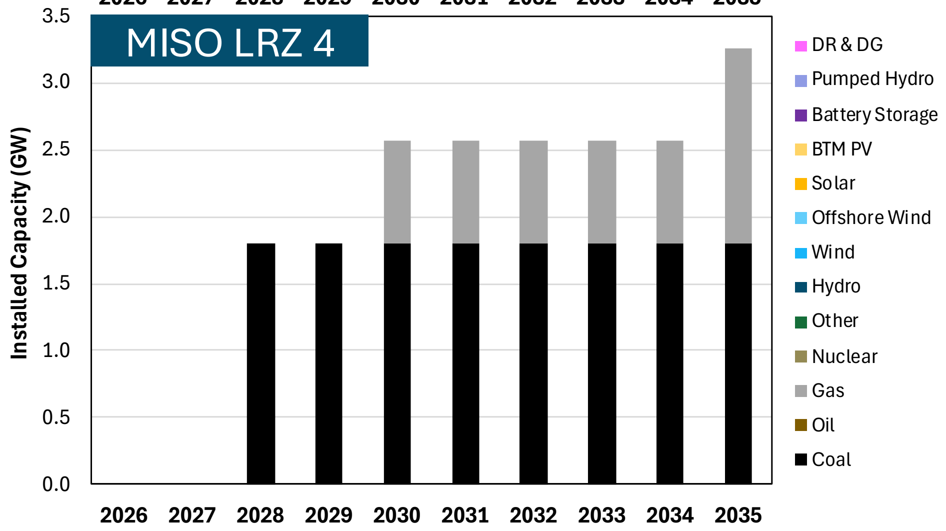
RA Study: Existing Fossil Resources are Scheduled to Retire

Significant amounts of coal and gas-fired generation is scheduled to retire in both regions over the next 10 years.





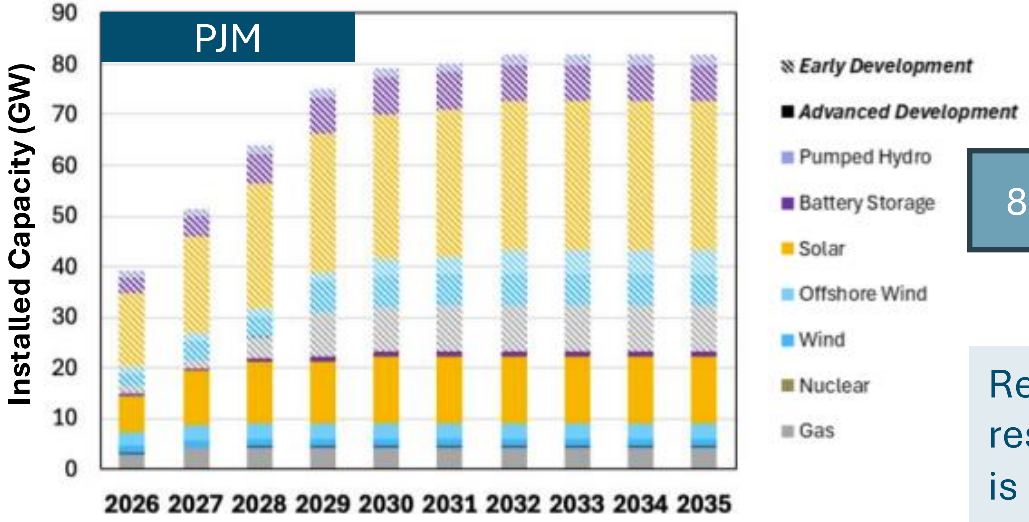




Sources: US EIA, S&P Global, and Hitachi Energy's Velocity Suite

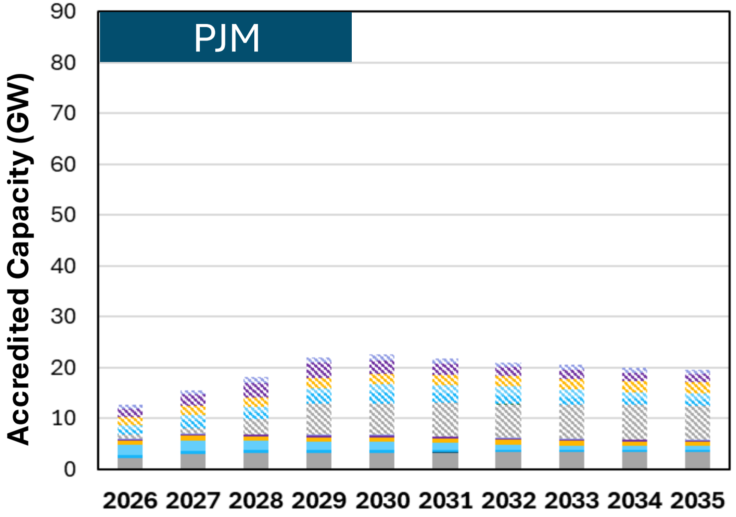
RA Study: New Resources Not Keeping Pace with Reliability Needs

New resources in development are mostly solar, wind, and batteries which have limited reliability value (in MW).

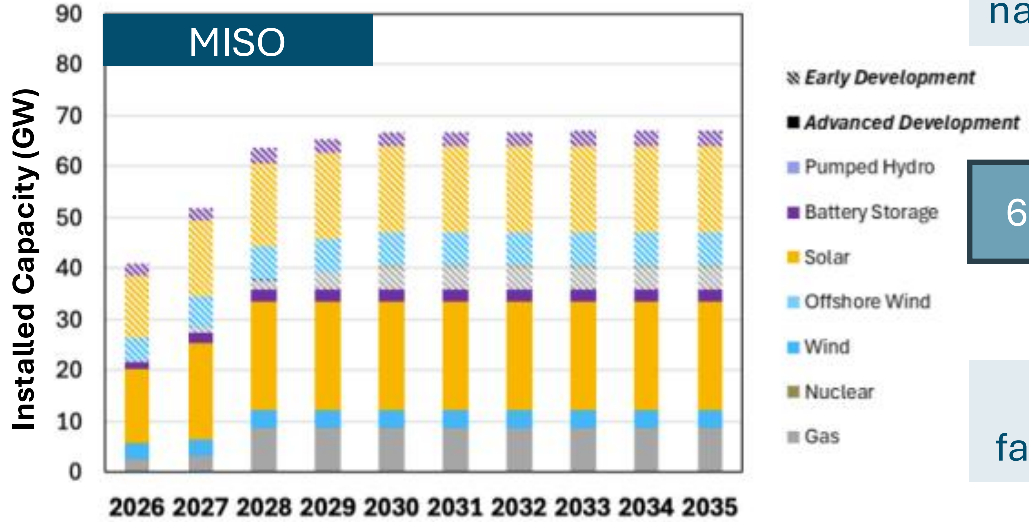


PJM

80 GW → 22 GW of reliability

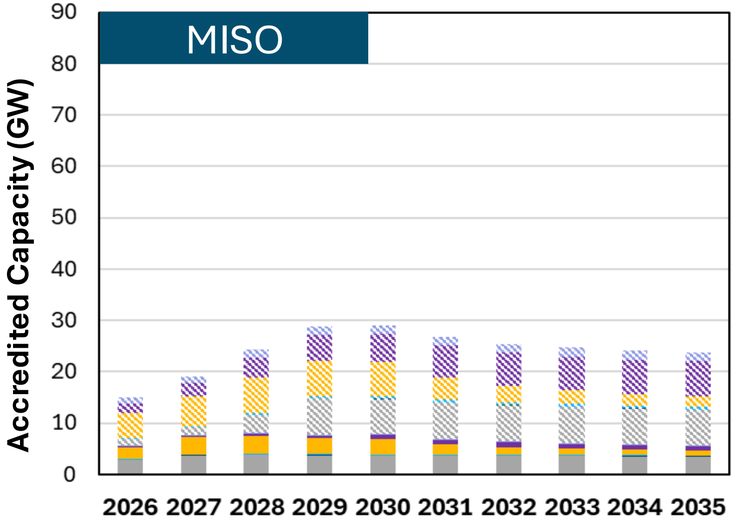


Reliability value of all new resources in development is much lower than total nameplate capacity...



MISO

65 GW → 27 GW of reliability

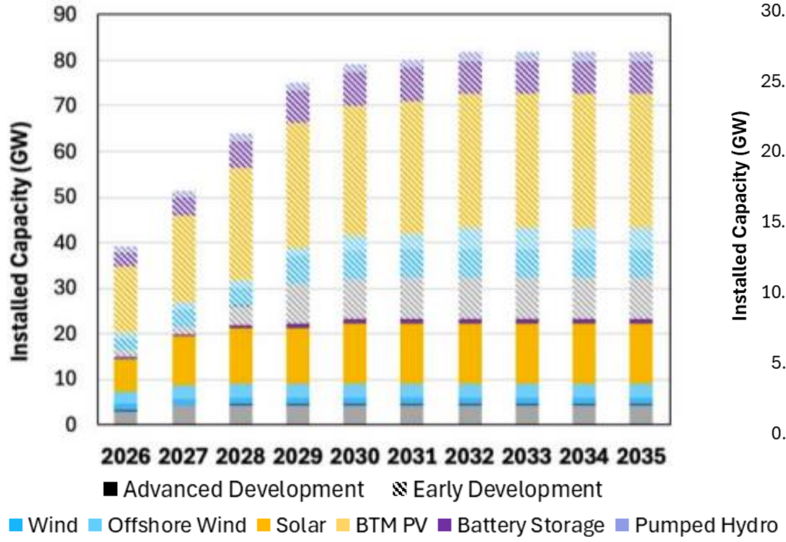


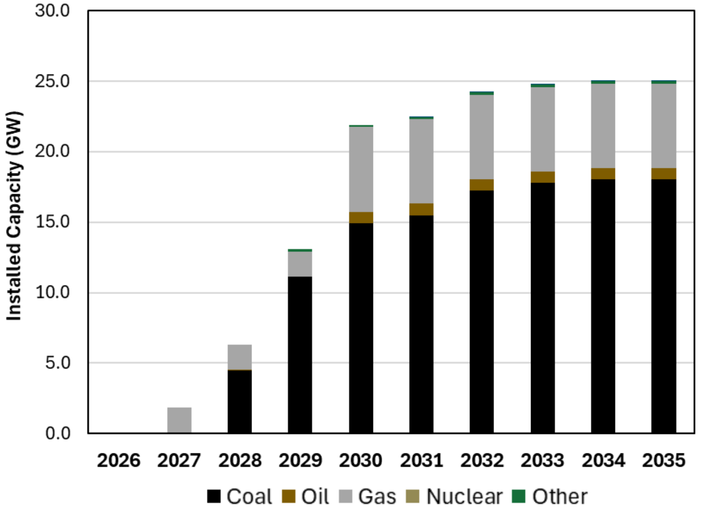
...and new resources also face delays to come online.

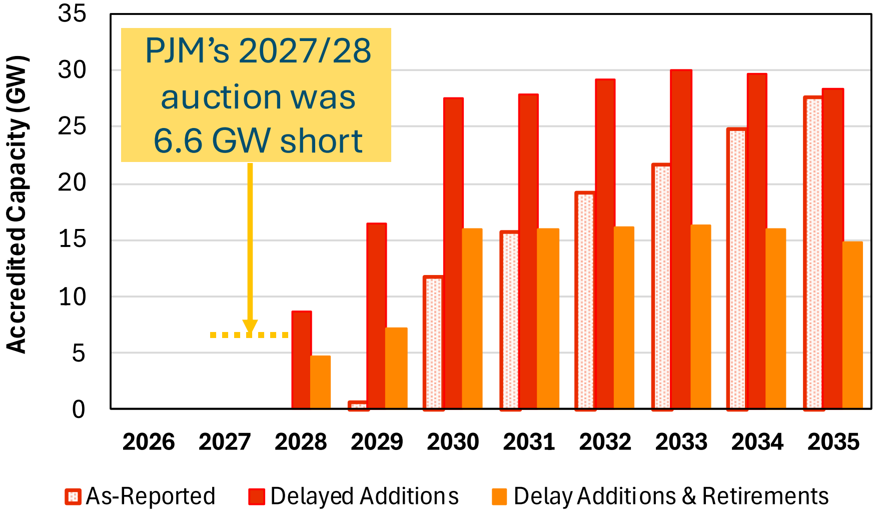
RA Study: PJM and MISO are Facing Growing Reliability Needs

Potential Resource Additions | **Potential Retirements** | **Range of RA Shortfall Risk**

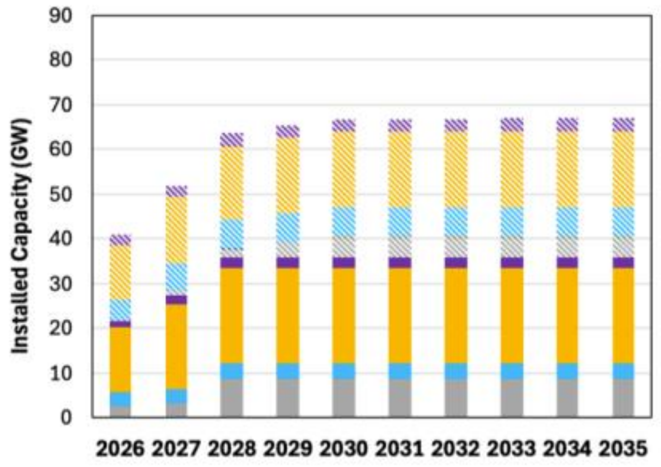
PJM

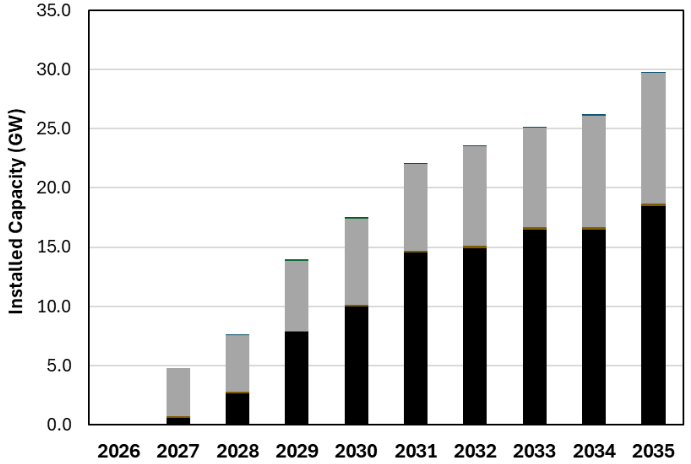


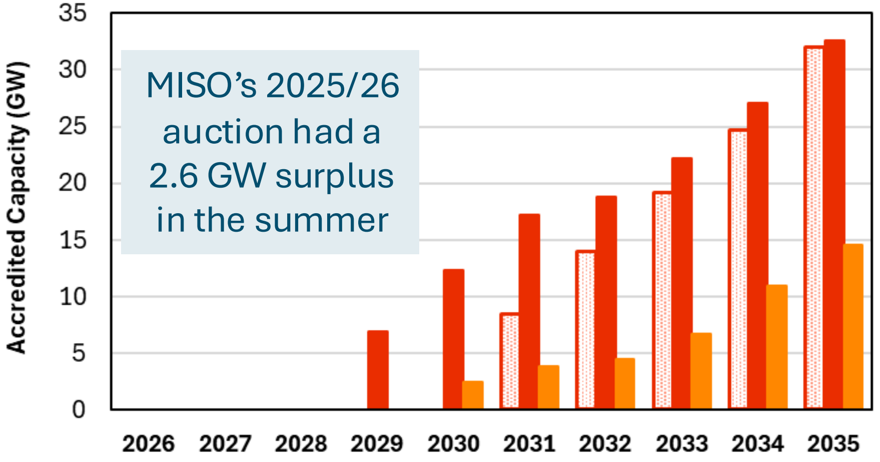




MISO







What is the State of Illinois Doing About All This?

Climate and Equitable Jobs Act (CEJA) (2021)

- Set new state-wide clean energy policies and implementing mechanisms
- Directed state agencies to perform periodic Resource Adequacy Studies, including to develop a Mitigation Plan to address any RA shortfalls identified.

RA Study (2025)

- RA Study assesses risk to Illinois and broader market regions and concludes that there is a resource adequacy shortfall risk which warrants analysis of options under a Mitigation Plan.

Clean and Reliable Grid Affordability Act (CRGA) (2026)

- CRGA establishes new tools for planning, procurement, and programs to meet clean energy and reliability needs
- CRGA establishes a new Integrated Resource Plan to guide implementing actions and policies of the state.

Mitigation Plan (2026 - ongoing)

Integrated Resource Plan (2026 - ongoing)

- State Agencies (ICC, IPA, IEPA) are developing coordinated studies for the Mitigation Plan and IRP
- Results of both studies will inform subsequent state actions.
- Additional studies, procurement efforts, and program designs are also underway in parallel.

How Illinois Is Supporting Customers and Advancing Renewable Energy

Jim Rouland
IPA Planning & Procurement Bureau Chief

Supporting Customers through IPA Programs

Active and Ongoing:

1. **Default service procurements** (block energy for Ameren IL, ComEd, and MidAmerican; and capacity hedge for Ameren IL)
2. **Utility-scale renewable energy procurements** (wind, solar, and brownfield sited PV)
3. **Customer programs**
   - **Illinois Shines** (also called the Adjustable Block Program or ABP)
   - **Illinois Solar for All** (ILSFA)
4. **Carbon Mitigation Credits** (CMCs)

In Development:

1. **Resource Adequacy Study & Integrated Resource Planning** (with ICC, IEPA, and IFA)
2. **Utility-scale energy storage procurements**
3. **New customer programs**
   - **Geothermal heating & hot water program**
   - **Storage for All**

Customer Savings & Support Today

Default service procurements

- Citizens Utility Board found default service saved customers approx. $2.17b (June 2015 – May 2025)

Utility-scale renewable energy procurements

- Through the 2024 Long-Term Plan, over 5 GW of wind, solar, and brownfield PV was procured (28 projects)

Solar	Wind
373 MW	200 MW
6 projects	1 projects

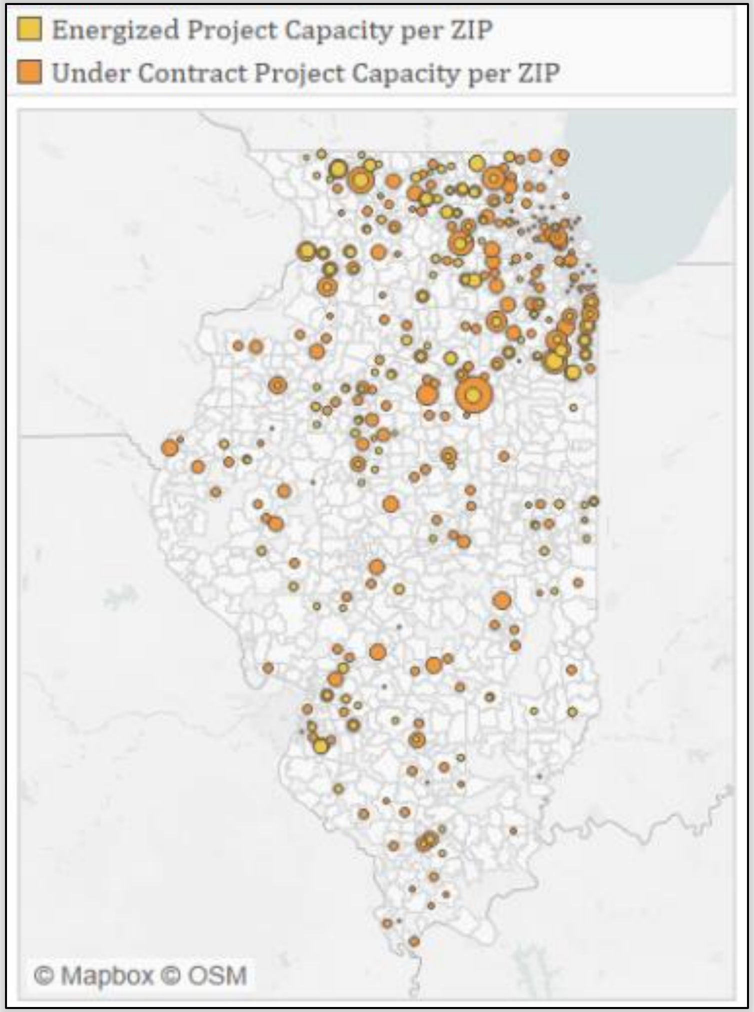
Solar	Wind
450 MW	750 MW
3 projects	2 projects

Brownfield Solar	Solar	Wind
25 MW	429 MW	1,277 MW
2 projects	4 projects	4 projects

Solar	Wind
488 MW	1,100 MW
2 projects	4 projects

Advancing Renewables With Customers

IL Shines - Community Solar Projects



Illinois Shines

Facilitating projects through clear access to information, vendors and financial support via REC prices, but providing far more to customers, developers and communities through the services and support of the Program.

Recent Key Statistics

- During FY25 alone, 66 Traditional Community Solar projects become energized, growing the total amount of TCS to 217.
- The programs have over 40,000 active community solar subscribers
- Over 2,500 Equity Eligible Persons have been registered through the IPA's Energy Workforce Equity Portal
- Successful Mentorship Program following the 2023 pilot. Second Mentorship Program cohort occurred in early 2025, with two additional cohorts created for the current Program Year!

Illinois Shines
Building Our Solar Future

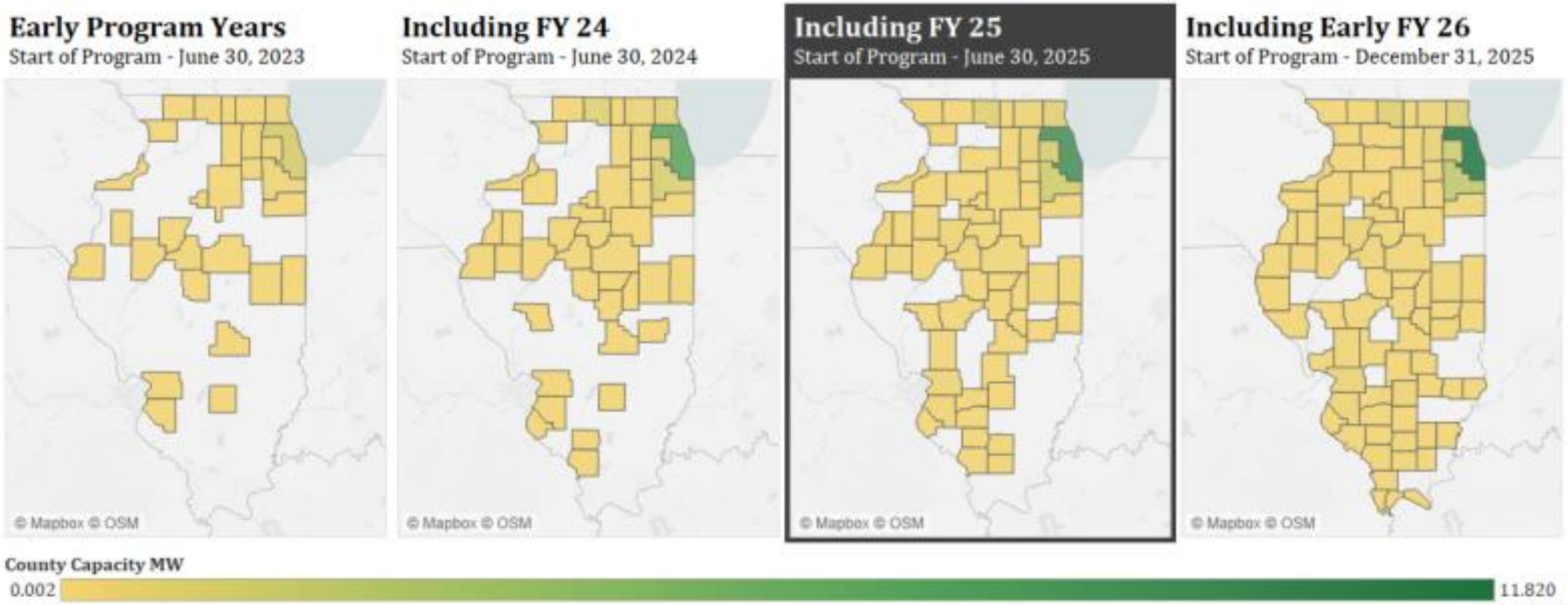
Advancing Renewables Through Customers

Illinois Solar for All

Providing income-eligible households, nonprofits, and public facilities access to solar – providing guaranteed savings to customers while ensuring equitable participation.

The Program enables action from within communities through Grassroots Educators and partnering with LIHEAP Administering Agencies.

ILSFA – Residential Small DG Projects



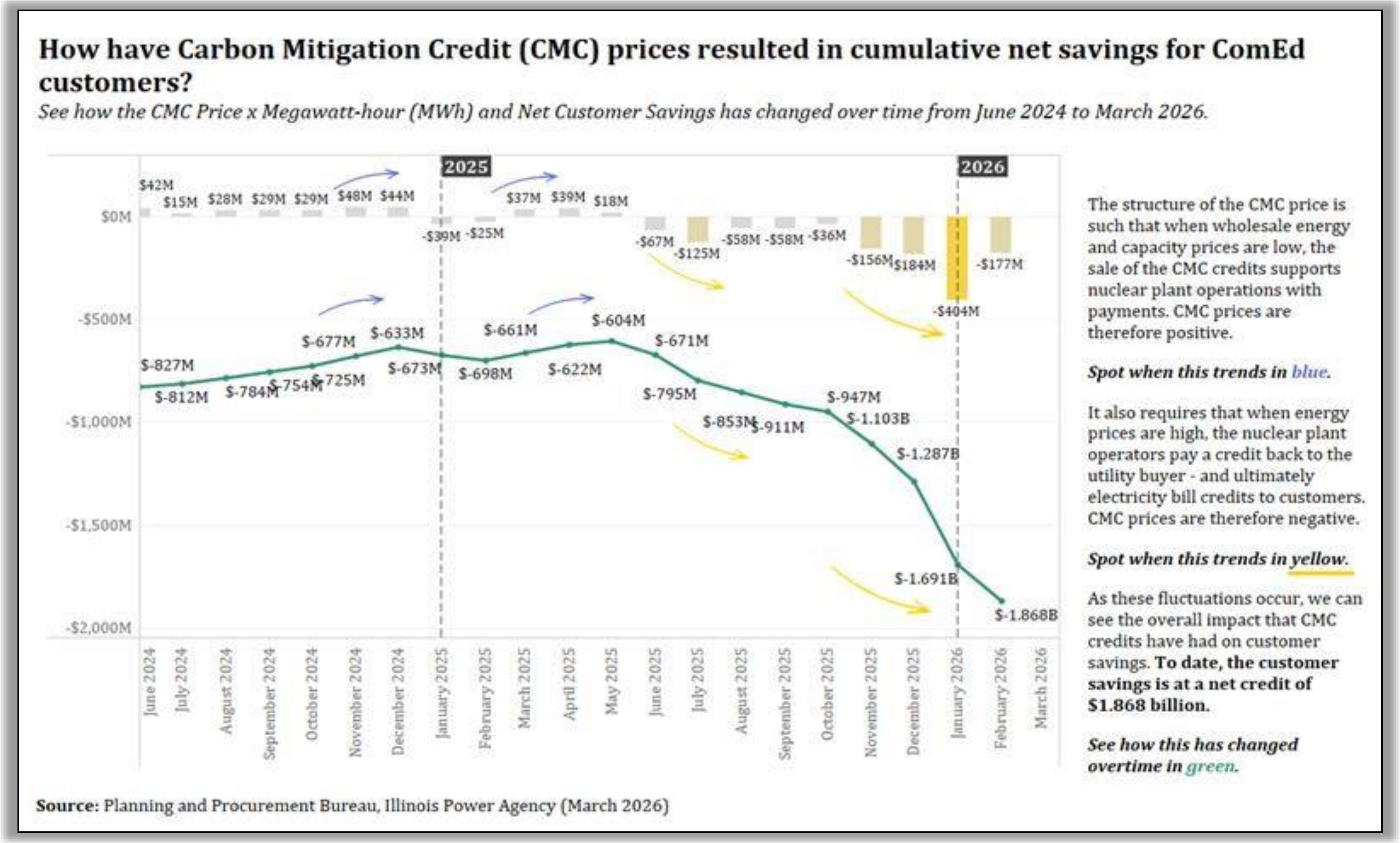
Recent Key Statistics

- 84% of ILSFA Projects promote energy sovereignty (participant ownership)
- More Residential Solar (Small) Projects were approved in FY25 than all preceding fiscal years combined!
- In 2025, eight LAAs participated – connecting LIHEAP households to ILSFA community solar offers.

Nuclear Energy Support Measures

Carbon Mitigation Credits (CMC)

- Over $2 billion in program savings to date
- Covers three nuclear facilities – Dresden, Byron, and Braidwood
- Initial savings driven by the spread between the contracted price less the capacity price and electricity prices
- Recently, additional savings due to investment tax credit refunds
- Learn more here



Value In Development

ILLINOIS POWER AGENCY

Resource Adequacy Study & Integrated Resource Planning (link)

- Issued the RA Study Report in Dec. 2025 which spurred need to develop a Mitigation Plan in 2026.
- The IRP is occurring in tandem with the Mitigation Plan - focused on complimentary aspects to the Mitigation Plan, but more expansive in scope.

Utility-scale Energy Storage (link)

- Codified through CRGA, seeks to secure 3 GW of storage – developed by ~2030
- Provides increased resource diversity to support, resource flexibility, and additional capacity to put downward pressure on capacity prices and support resource adequacy

New Customer Programs

- **Geothermal** – an initial step to support a growing clean energy market for geothermal heating and hot water.
- **Storage for All** – to be considered by the IPA through the forthcoming Energy Storage Procurement Plan (2027); looks to support energy storage development for income-eligible communities in concert with the Illinois Solar for All Program

For More Information!

ILLINOIS POWER AGENCY

- IPA Clean Energy Dashboard (https://cleanenergy.Illinois.gov)

- View the IPA's Annual Report
  - Full report: Link
  - Or use the QR code on the right!

Scan for Annual Report

- For expanded access to IPA Renewables Programs and other Renewables Resources (https://ipa.Illinois.gov./renewable-resources.html)

Q&A

Contact Information

James (Jim) Rouland
IPA Planning & Procurement Chief
james.rouland@illinois.gov

Will Gorman
Research Scientist at Lawrence Berkeley National Laboratory
wgorman@lbl.gov

Nathan Miller
Senior Director at Energy + Environmental Economics
nathan.miller@ethree.com

Megha Hamal
IPA Chief Strategy & Communications Officer
megha.hamal@illinois.gov