Title
Retail Electricity Price and Cost Trends: 2024 Update

Authors
Forrester, Sydney
Satchwell, Andrew
Barbose, Galen L
et al.

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MARKET

Market and Retail-rate Knowhow for the Energy Transition

Retail Electricity Price and Cost Trends

2024 Update

December 2025

Sydney Forrester[1], Andrew Satchwell[1], Galen Barbose[1], Evan Cappers[1], Cesca Miller[1], and Andrew Alberg[2]

[1]Lawrence Berkeley National Laboratory
[2]National Renewable Energy Laboratory

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Report Outline

- Overview and Motivation
- Data and Methods
- Retail Electricity Price Trends
- Utility Cost Trends
- Retail Sales, Behind-the-Meter Resources, and Other Drivers of Load Growth
- Conclusion
- Appendix

Overview

Summarizes recent trends in retail electricity price levels and price drivers in the United States

Trends reported for 2019 through 2023 using publicly-available data for:

- Average retail electricity prices, retail sales, and utility revenues
- Utility capital expenditures, operations and maintenance costs, and fuel and purchased power costs
- Retail electricity sales impacts from behind-the-meter resources

Describe trends nationally and, where possible, at the state or regional levels

Qualitative case studies highlight recent and/or regionally-specific issues contributing significantly to retail electricity price trends:

- ➢ Recent high load growth
- ➢ Generation cost overruns
- ➢ California wildfire expenses
- ➢ Default residential time-of-use rates

This report does <u>not</u>:

- ➢ Track changes in retail rate *structures*
- ➢ Precisely quantify how each driver has impacted retail electricity prices
- ➢ Address every factor impacting rates (esp. those that are utility-specific)

Background and Motivation

- Retail electricity prices reflect the direct costs to generate and deliver electricity to consumers, including capital expenditures, fuel and power purchase costs, financing costs, and others
- Under cost-of-service regulation, retail electricity prices are set to recover a specified amount of revenue for a specified amount of retail electricity sales
- This report is intended to serve as a reference document* for the diverse set of decision-makers impacted by changes in retail electricity prices and to provide a factual basis for assessing recent changes in retail electricity prices and key underlying drivers
- Focuses on the past five years: long enough to see broad trends and capture price changes made through periodic rate cases

Retail electricity prices have broad impacts on:

- Electricity consumption levels
- Consumer investments in energy technologies (e.g., energy efficiency, onsite generation, electric vehicles, heat pumps)
- Household energy burden and energy insecurity
- The cost of goods and services throughout the economy

* Builds on prior Berkeley Lab research exploring retail electricity pricing drivers (e.g., Barbose 2017, Cappers et al. 2021, Cappers and Murphy 2019)

Data and Methods

Key Retail Electricity Price Drivers

Revenue Requirements ÷ **Electricity Sales** = **Retail Electricity Prices**

Utility Costs

The revenue requirement is equal to the utility's costs to serve retail customers

- Fuel and Purchased Power
- Operations and Maintenance
- Capital Expenditures/Depreciation
- Other (see examples on page 43)

Utility costs to produce and deliver electricity are determined by the amount of electricity sales

The temporal and locational BTM resource characteristics, as well as program design details, determine cost impacts (see explanation on page 25)

Behind-the-Meter Resources

Behind-the-meter (BTM) resources can either increase or decrease sales depending on deployment specifics (see explanation on page 25)

- Energy Efficiency
- Distributed PV
- Electrification (EVs, heat pump)
- Time-Varying Rates

Schematic is not exhaustive; focuses on key drivers explored in this report

Primary Data Sources

Data	Source
Retail electricity prices, sales, and revenues	EIA Form-861
Utility capital expenditures, operations and maintenance (O&M), and fuel and purchased power (FPP) costs	FERC Form-1
Behind-the-meter solar generation	EIA Form-861m and Form-860
Ratepayer-funded electric energy efficiency program savings	ACEEE state scorecard reports
Federal appliance efficiency standards electricity savings	Meyers et al. 2016
Time-based rate enrollment	EIA Form-861
Heat-pump monthly sales (air-source heat pumps)	Air-conditioning, Heating, Refrigeration Institute (AHRI)
Electric vehicle sales (light duty vehicles)	Argonne National Laboratory light duty electric drive vehicles monthly sales updates

Other Key Methodological Details

Conventions

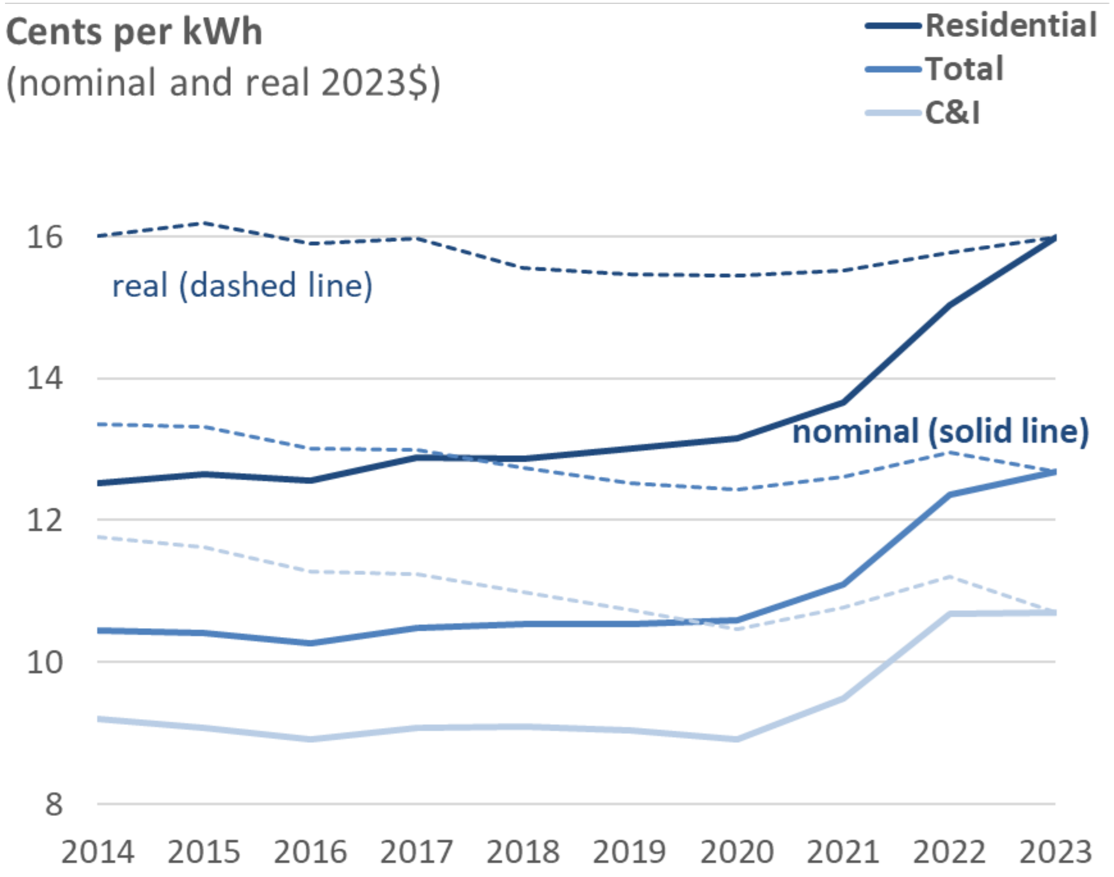
- Dollar values are reported in nominal terms (i.e., not inflation-adjusted), unless otherwise stated
- Trends over time are described in some cases in terms of *average annual growth rate* (AAGR), defined as the mean year-over-year growth-rates during the analysis timeframe (less sensitive to starting/ending-year values than the compound annual growth rate)

Key Data Limitations

- FERC Form-1 data are available for only a subset of utilities over the historical analysis period; only utilities with complete data are included in the trends derived from that data
- Even for utilities where FERC Form 1 data is available, not all utilities report in all cost categories depending on their regulatory structure and other financial and operational characteristics (see page 42 for details on FERC Form 1 data coverage in this study)
- Trends are reported at the most granular geographic level for which complete or reliable data are available

Retail Electricity Price Trends

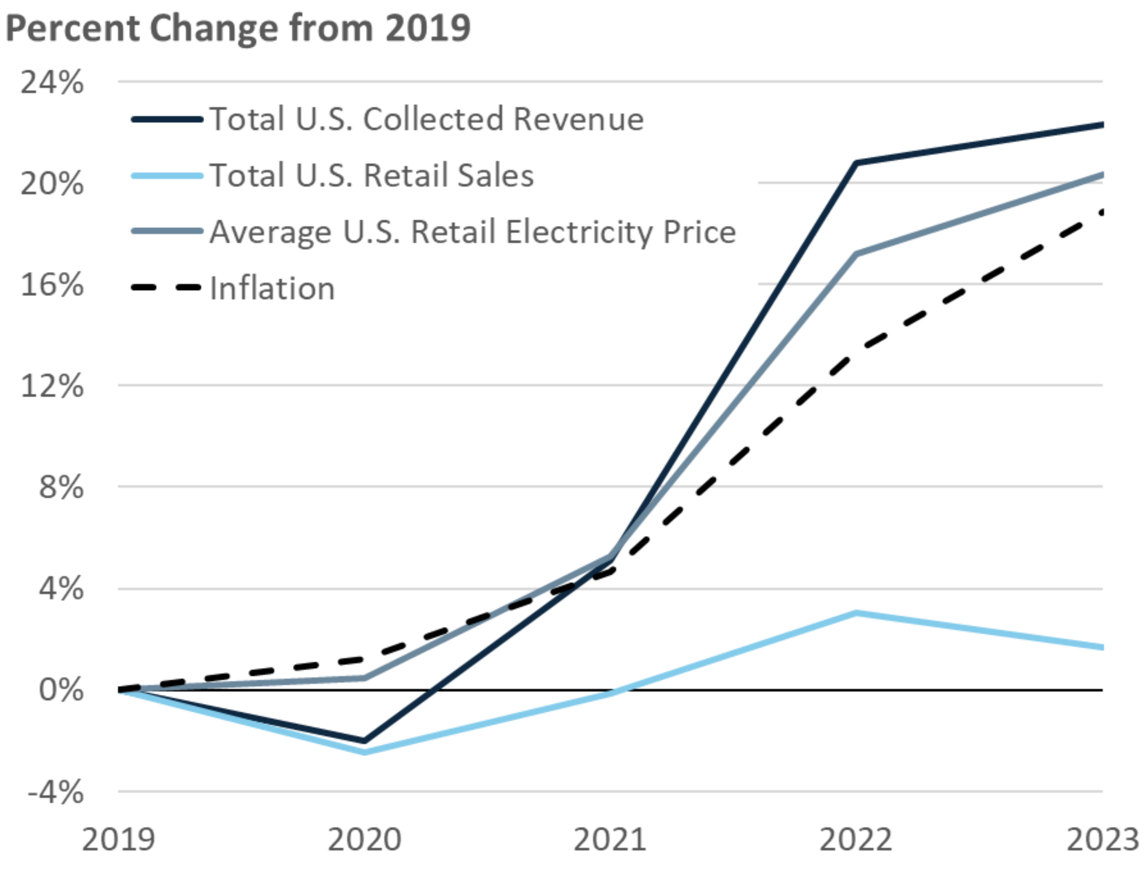
U.S. Average Retail Electricity Prices over Time



Notes: Average retail electricity prices calculated as the total revenues from retail electricity sales divided by total retail electricity sales. Inflation-adjustment made using the Consumer Price Index averaged over each respective year's 6 months.

- In nominal terms, U.S. avg. retail electricity prices rose by 2.2 cents/kWh over the decade, or 0.2 cents/kWh (2.5%) annually
- Most change took place from 2019-2023 (the focal time period for this report) where rates rose 2.1 cents/kWh, or 0.5 cents/kWh (4.8%) annually
- Over the focal 5-year period (2019-23), U.S. average retail electricity prices kept pace with inflation and average residential prices rose more than commercial & industrial (C&I) prices

Decomposing Price Changes into Revenue and Retail Sales



Source: EIA 861

- Average retail electricity prices equal total collected revenues divided by retail sales
- Since 2019, collected revenues increased by more than 20%, roughly tracking inflation, while retail sales were fairly flat
- Suggests that recent increases in retail electricity prices have been driven principally by rising revenues (costs) unrelated to load growth
- While load growth was not a major driver of recent cost-growth at the national level, some states and utilities have seen significant recent load growth and forecast continued growth into the future (as discussed later)

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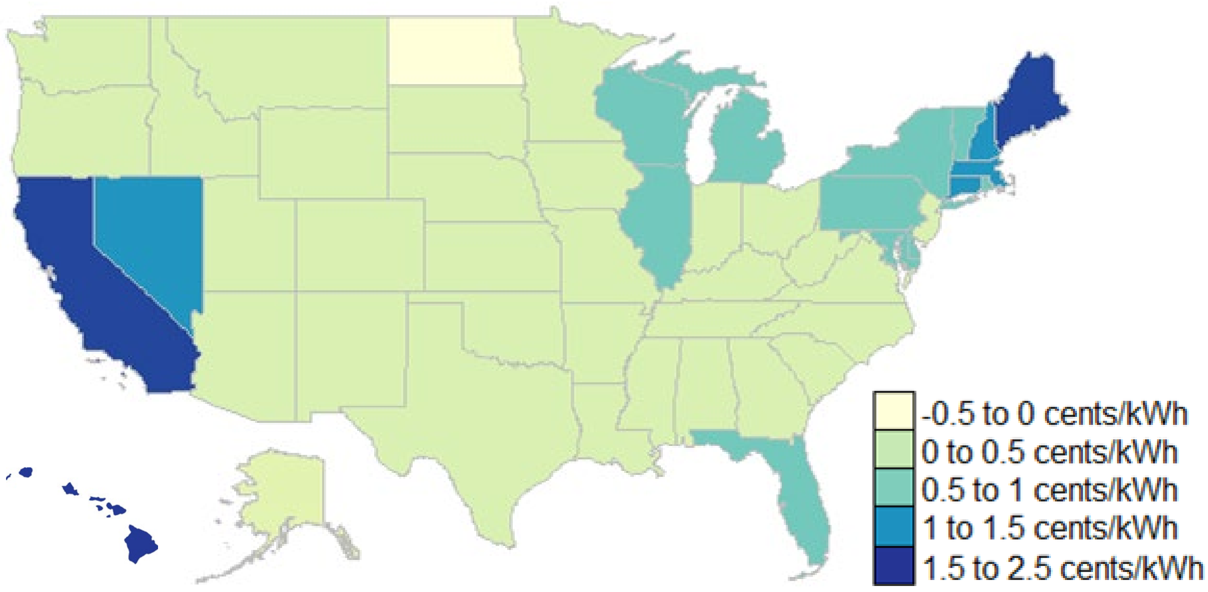
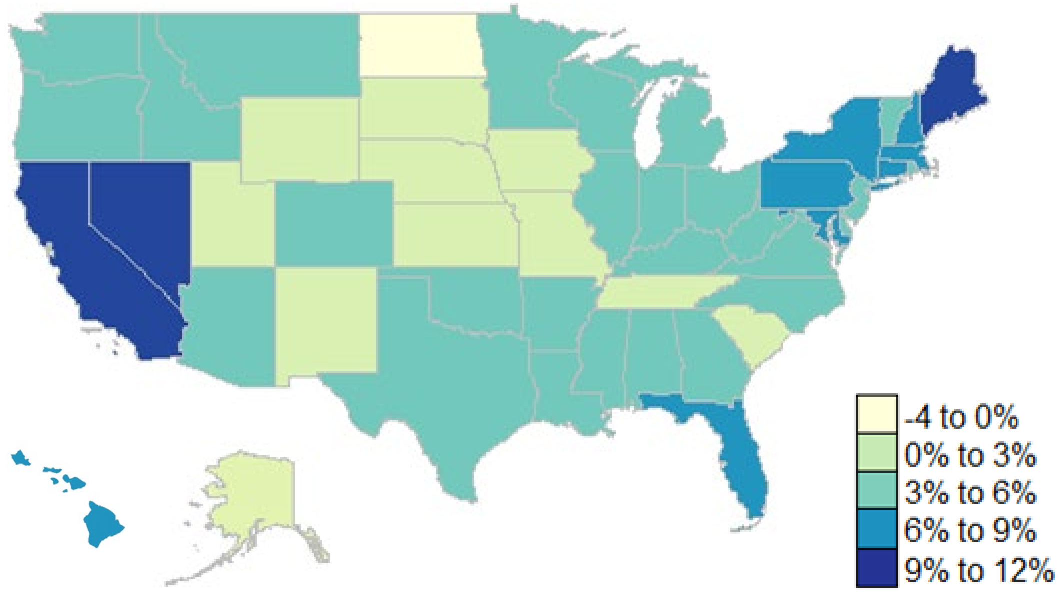
Changes in State-Level Retail Electricity Prices (2019-2023)

Average annual change (nominal cents/kWh)



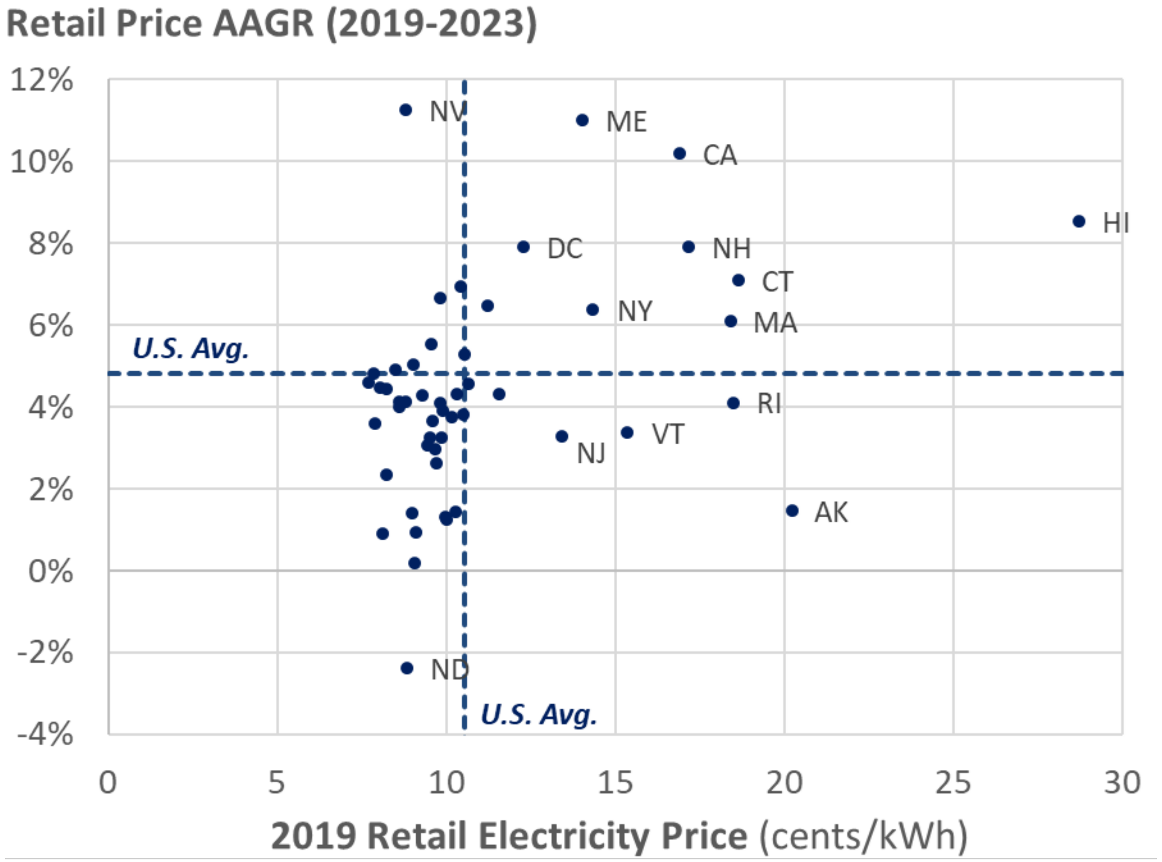
AAGR (nominal)



Source: EIA 861

- Prices in most states rose by less than 0.5 cents/kWh per year, and by <6% per year, with some variability in AAGR based on differences in absolute retail price levels across states
- Larger increases occurred throughout the Northeast and parts of the upper Midwest; largest increases were in HI (2.5 cents/kWh per year), CA (2.0 cents/kWh per year), and ME (1.7 cents/kWh per year)
- Prices in just one state (ND) fell over this period (0.2 cents/kWh per year)

Comparison of Price Changes for Low vs. High Priced States



Source: EIA 861

- States with higher-than-average retail rates saw faster electricity price increases than states where rates were relatively cheaper
  - E.g., among the 10 states with the highest prices in 2019, prices rose by 7% annually from 2019-2023, compared to 4% in the 10 lowest priced states
- The gap between high and low-priced states is therefore further widening
  - The difference in average prices between the 10 highest and 10 lowest priced states rose from 10 cents/kWh in 2019 to 14 cents/kWh by 2023

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Utility Cost Trends

Key Retail Electricity Price Drivers: Utility Costs

Revenue Requirements ÷ **Electricity Sales** = **Retail Electricity Prices**

Utility Costs

The revenue requirement is equal to the utility's costs to serve retail customers

- Fuel and Purchased Power
- Operations and Maintenance
- Capital Expenditures/Depreciation
- Other (see examples on page 43)

Utility costs to produce and deliver electricity are determined by the amount of electricity sales

Behind-the-Meter Resources

Behind-the-meter (BTM) resources can either increase or decrease sales depending on deployment specifics (see explanation on page 25)

- Energy Efficiency
- Distributed PV
- Electrification (EVs, heat pump)
- Time-Varying Rates

The temporal and locational BTM resource characteristics, as well as program design details, determine cost impacts (see explanation on page 25)

Schematic is not exhaustive; focuses on key drivers explored in this report

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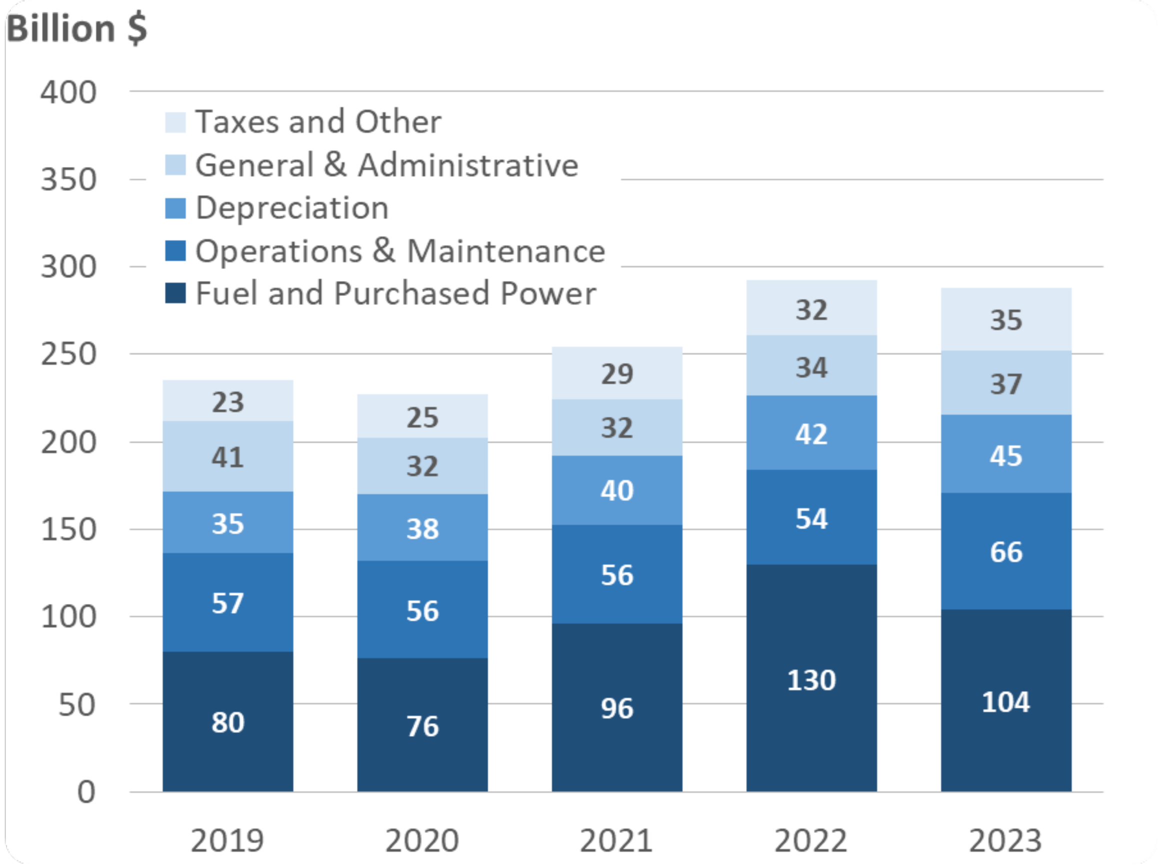
Expenses for Major U.S. Investor-Owned Electric Utilities



Notes: Data are from FERC Form 1, as summarized in EIA's Electric Power Annual (https://www.eia.gov/electricity/annual/html/epa_08_03.html). Various expense categories are consolidated for the purpose of this figure.

- Data are for a subset of all U.S. utilities, but help to illustrate the composition of utility expenses and how each component has grown in recent years
- Fuel and purchased power (FPP) is the largest expense, followed by operations & maintenance (O&M), and then depreciation
- All types of utility expenses except General & Administrative rose from 2019-2023
- FPP costs were the largest increase, representing roughly half of the total increase, though have abated since 2022
- The remaining increase in expenses was split roughly evenly across O&M, depreciation, and taxes/other

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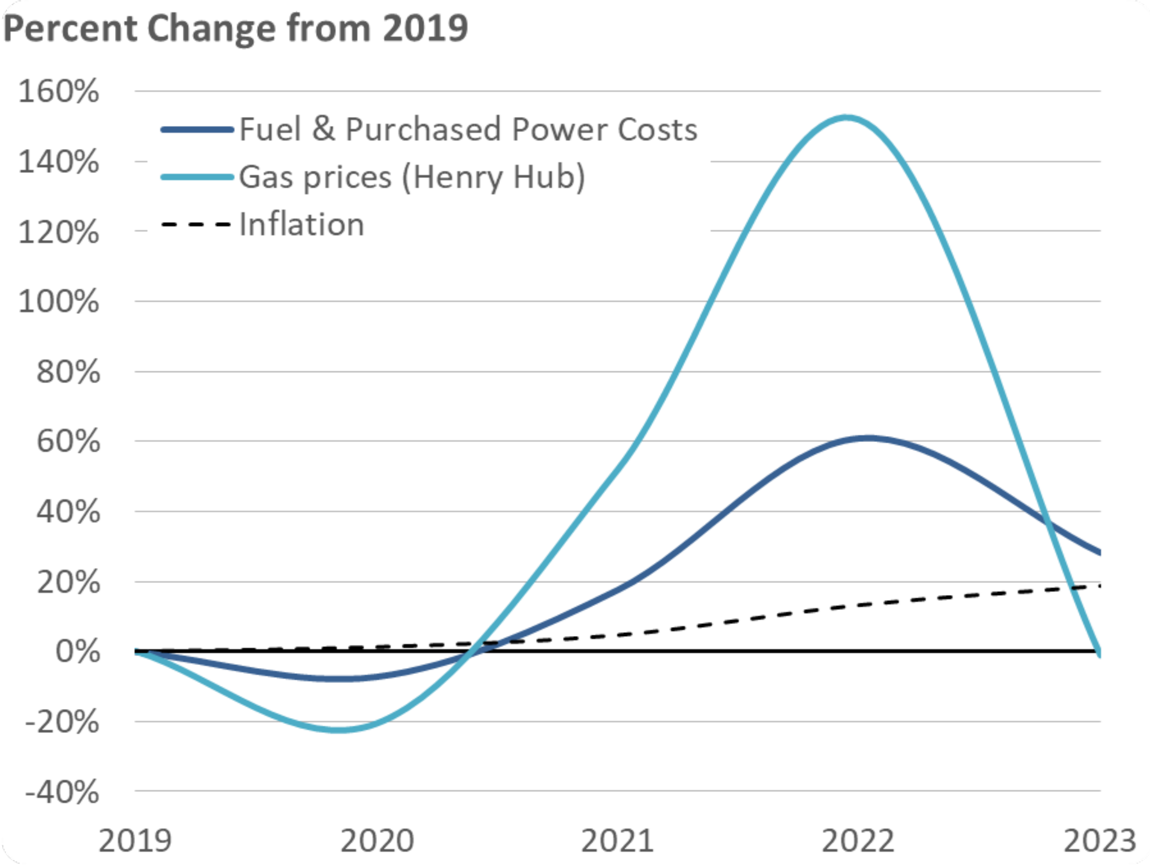
Changes in Fuel and Purchased Power Costs



Notes: Gas price data from EIA. See page 44 for absolute values (https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm)

- Utility FPP costs have risen and fallen with natural gas prices, which comprise roughly 40% of the U.S. electric generation mix
- The effect of gas prices on electricity prices is muted, given other fuel sources and financial hedges, among other factors
- While natural gas prices in 2023 returned to 2019 levels, FPP costs remain elevated at roughly 30% above 2019 levels
- FPP costs also tend to rise and fall with retail sales volume, though U.S. retail sales remained fairly flat over the past 5 years

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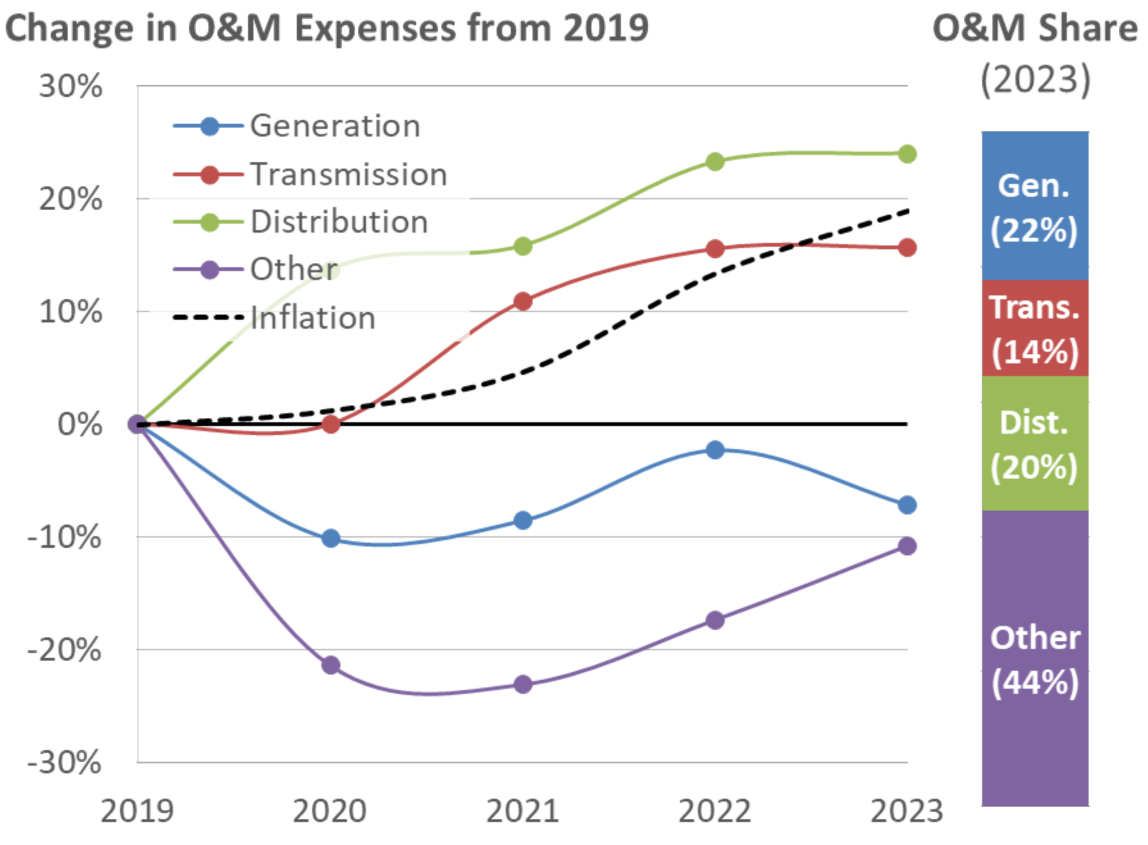
Changes in Operations & Maintenance Costs



Notes: In the left-hand figure, each line is based on those utilities with data across all years for the given O&M category. The stacked bar chart on the right is based on the subset of 83 utilities with data reported for all O&M categories in 2023. See page 43 for breakdown of "other" and page 44 for absolute values across all categories.
Source: FERC Form 1

- Among those utilities reporting O&M costs across all categories in 2023, "other" O&M represents the largest share (44%), which includes salary and property, followed by generation, distribution, then transmission (see stacked bars)
- Since 2019, distribution-related O&M costs have grown the most, followed by transmission
- In contrast, generation and other O&M costs have fallen roughly 10% since 2019
- O&M cost trends have varied regionally (see page 46): most notably, with much higher rates of distribution-related O&M cost growth in the West

Case Study: California wildfire-related expenses

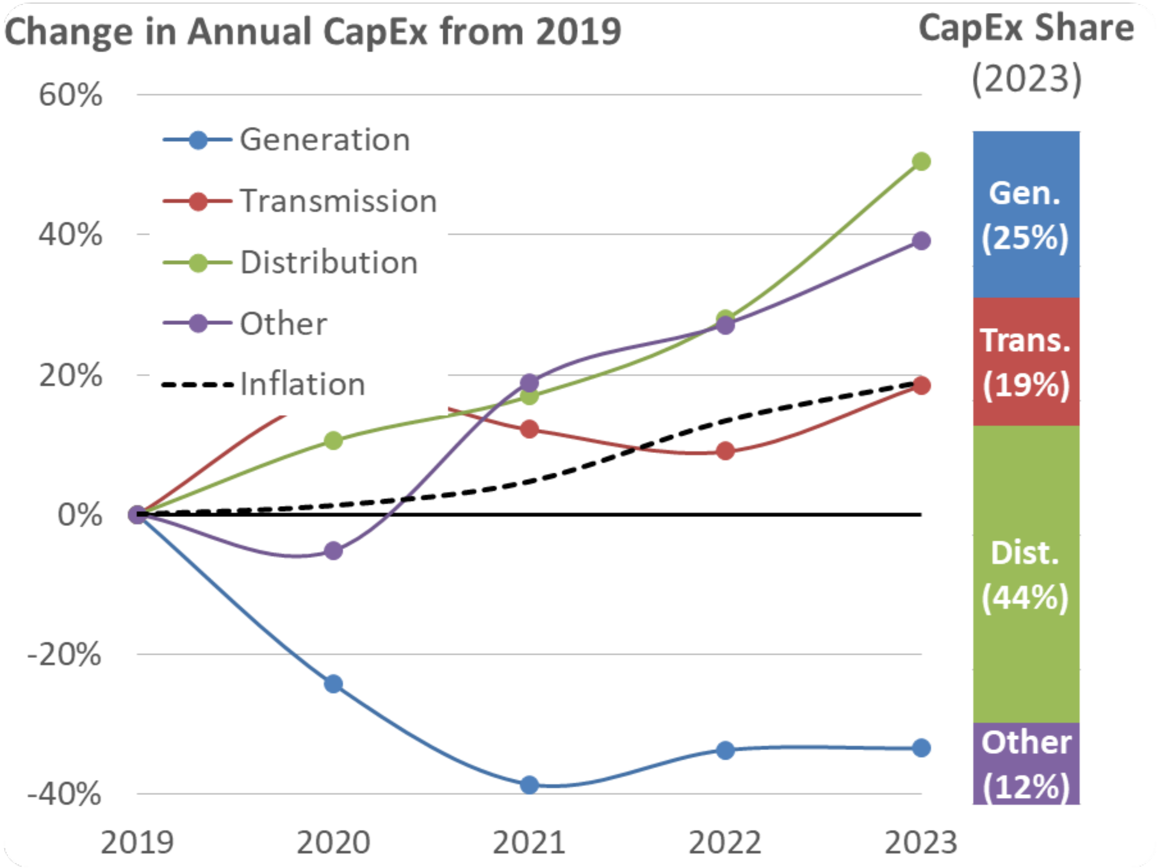
California's three largest investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), are responsible for most of the electricity transmission and distribution service in the state, including through high wildfire risk areas. From 2018 to 2022, wildfire agencies have responded to more than 7,200 fires each year on average in California (Cal Fire, 2024). The sources of the California wildfires vary among human activities and natural events, and all three of California's largest IOUs have been found guilty of igniting at least one wildfire within the past 20 years. Notably, PG&E was convicted of causing the Camp Fire in 2018 that killed 84 people and caused ~$15B in damages (Warner et al., 2024).

Partially in response to the Camp Fire, California state legislators established a Wildfire Fund in 2019 to reimburse future wildfire damage-related costs. The Wildfire Fund is partially funded by ratepayers via a non-bypassable charge of ~$0.006/kWh (or ~$3.00 per month for an average residential customer) and is intended to reduce long term costs to ratepayers, decrease financial risk for utility shareholders, and protect against increased future debt (CPUC, 2022). Through 2023, the Wildfire Fund has received more than $13B, of which ~21% has come from California IOU ratepayers (California Catastrophe Response Council, 2024).

Additionally, in 2018, the California Legislature established requirements for each IOU to develop a Wildfire Mitigation Plan (WMP), outlining actions and spending on wildfire mitigation (Wildfire Mitigation, 2018). The most significant WMP spending category is "grid design and system hardening," which includes investments in undergrounding distribution system equipment, covered conductor installations, and upgrading distribution lines and poles. These costs drive utility O&M and capital expenditures and are recovered through IOU base electricity rates, in addition to the Wildfire Fund charge.

The three IOUs' average retail electricity rates have increased significantly (~50%) over the past five years. There are several factors that have raised electricity rates in California. According to the California Public Utilities Commission (CPUC), these include increased distribution costs and, since 2020, are due to "improvements to the distribution system for wildfire mitigation", among other reasons. (CPUC, 2024).

Growth in Utility Capital Expenditures



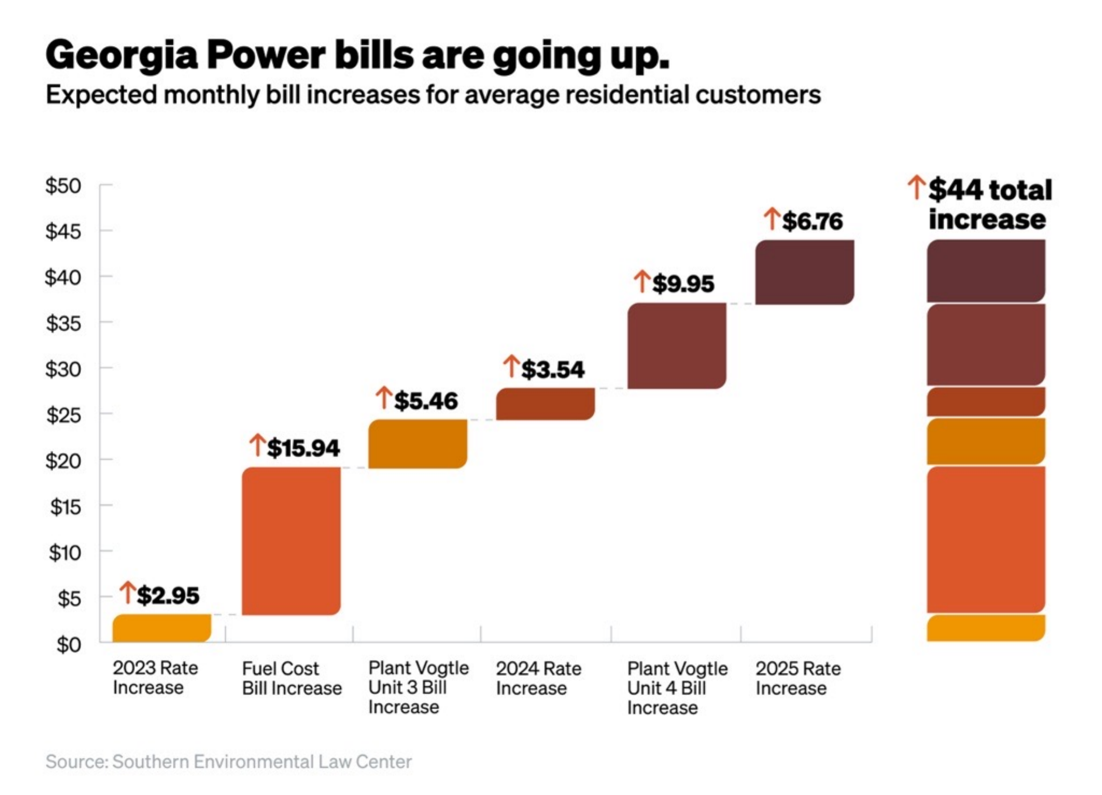
Notes: In the left-hand figure, each line is based on those utilities with data across all years for a given CapEx category. The stacked bar chart on the right is based on the subset of utilities with data reported for all CapEx categories. Values represent additions. See page 43 for breakdown of "other" and page 44 for absolute values across all categories. Source: FERC Form 1

- Capital expenditures (CapEx) are recovered through retail electricity prices gradually over time (e.g., through depreciation)
- Distribution is currently the largest source of CapEx (44% of the total in 2023; see page 45 for breakdown by functional category)
- Distribution CapEx has grown steadily and at a rapid clip—growing by 50% over 2019-2023
- Transmission CapEx fluctuated from year to year, with 2023 levels up 20% from 2019
- In contrast, generation CapEx declined by 40% from 2019-2021, then remained flat
- Trends are generally consistent across regions (see page 47)

Case Study: Utility cost overruns

Large utility infrastructure projects can cost more and take longer to complete than initially estimated, which increases utility CapEx costs. Utility cost overruns may impose additional financial costs and risks to ratepayers, including increased electricity prices and delays in receiving the benefits of new power system resources. One recent notable example is Georgia Power's Vogtle nuclear power plant Units 3 and 4, which began construction in 2009 as an addition to Vogtle's Units 1 and 2, built in 1987 and 1989, respectively (Georgia Power, n.d.). With the additional generation capacity from these new units, Vogtle became the highest capacity nuclear power plant in the United States at nearly 5 Gigawatts (International Atomic Energy Agency, n.d.).

The project originally had a budget of $14B and was expected to be operational in 2016-2017, with Georgia Power being the primary owner (~46% ownership). Instead, Vogtle Units 3 and 4 cost approximately $35B, and became operational seven years later than expected in 2023 and 2024. Reasons for the delay and cost overrun included supply chain delays, shortages in skilled workforce, and impacts of the COVID-19 pandemic (Amy, 2023).



Partly because of the Vogtle Unit 3 and 4 costs, Georgia Power's average electricity rate has increased by 33% in the past 3 years (Georgia Public Service Commission, n. d.). Residential average bill increases are estimated at ~$5 per month for Unit 3 costs and between ~$9 and ~$11 per month for Unit 4 costs (Southern Environmental Law Center, 2024; Amy, 2023; Georgia Power, 2023a; Georgia Power, 2023b).

Retail Sales, Behind the Meter Resources, and Other Drivers of Load Growth

Key Retail Electricity Price Drivers: Behind-the-Meter Resources

Revenue Requirements ÷ **Electricity Sales** = **Retail Electricity Prices**

Utility Costs

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Behind-the-meter (BTM) resources can either increase or decrease sales depending on deployment specifics (see explanation on page 25)

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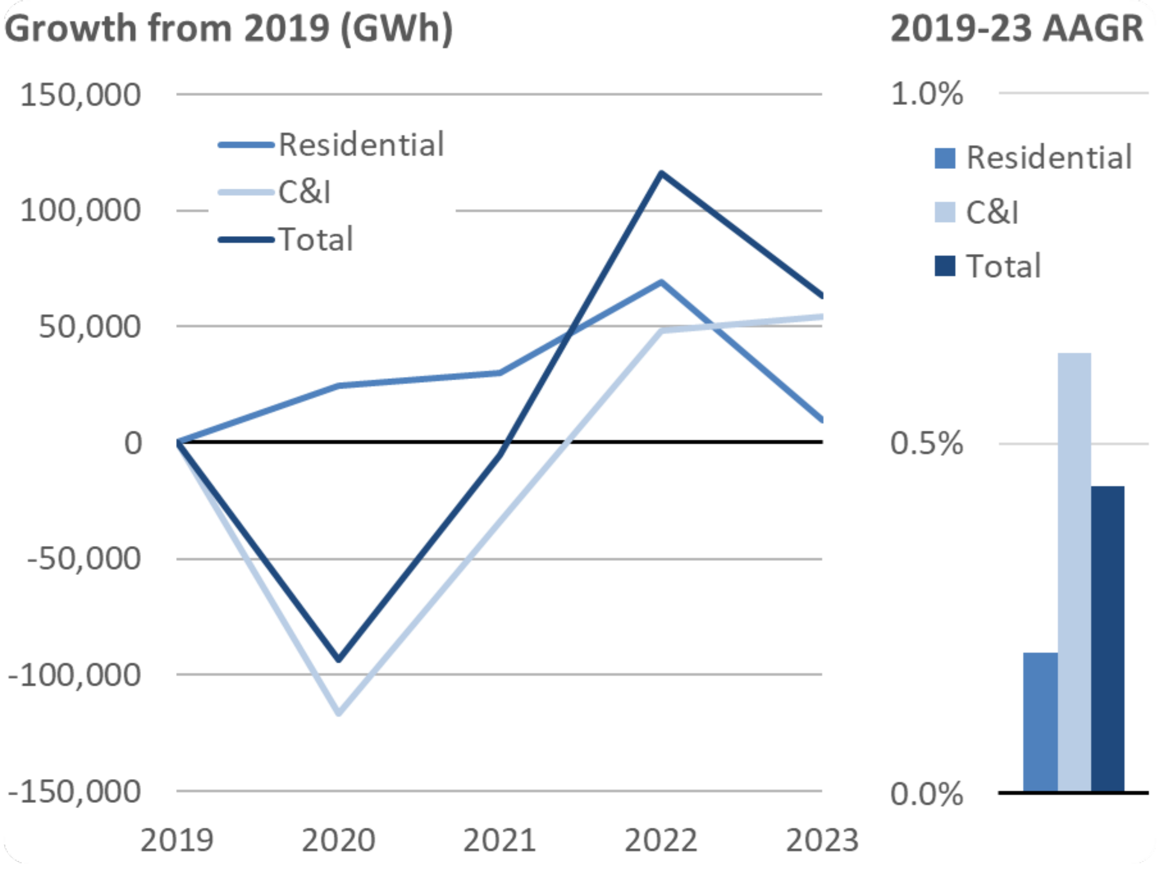
- Distributed PV
- Electrification (EVs, heat pump)
- Time-Varying Rates

Schematic is not exhaustive; focuses on key drivers explored in this report

Impacts of Load Growth and BTM Resources on Retail Prices

- Load growth is impacted by economic activity (e.g., data centers, manufacturing growth) and changes in end-use technology (e.g., behind-the-meter resources)
- Load growth imposes additional utility costs to be recovered through retail rates, while also spreading the cost of prior investments across a broader base of retail electricity sales
  - Can either increase or decrease retail electricity prices, depending on how those effects balance out
  - Impacts also depend on regulatory and ratemaking factors (e.g., regulatory lag, etc.)
- Behind-the-meter (BTM) resources
  - Can either accelerate load growth (e.g., electrification) or dampen load growth (e.g., energy efficiency, onsite generation), while demand flexibility primarily dampens peak demand growth
  - Cost impacts (either positive or negative) depend very much on the temporal profile of the BTM resources and their location on the grid
  - May also incur programmatic costs (e.g., rebates from ratepayer-funded efficiency programs)
- As a reminder, it is beyond the scope of this report to estimate the impact of BTM resources or load growth on retail electricity prices (see page 37 for a discussion of future research and analysis)

Retail Electricity Sales Growth (2019-2023)

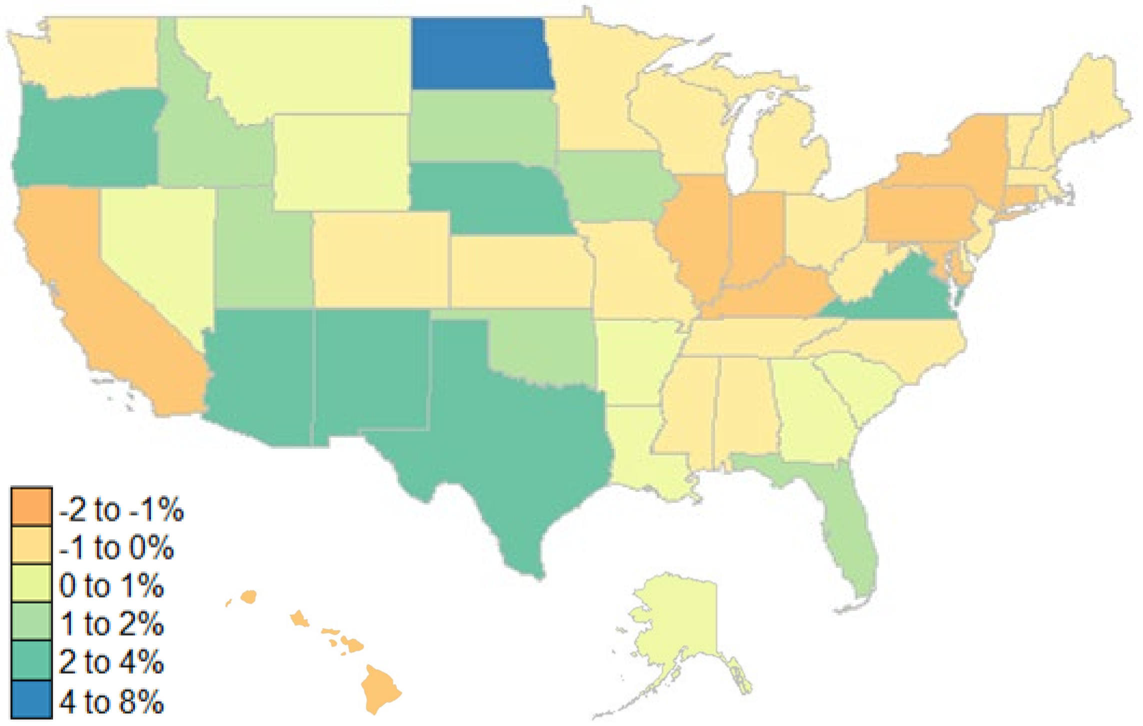


Notes: Data are from EIA 861 annual data

- Total retail electricity sales grew by roughly 60,000 GWh from 2019-2023, or roughly 15,000 GWh per year, on average
- Equates to an average annual growth rate of 0.4% per year (0.2% for residential and 0.6% for C&I)
- However, year-over-year growth fluctuated considerably over this period
  - C&I sales fell sharply from 2019-2020 with the onset of the COVID-19 pandemic, rebounding the following year
  - Residential sales dropped markedly from 2022-23, partly due to milder weather (NOAA, 2024), while C&I sales remained flat

Average Retail Sales Growth across States

Retail Electricity Sales AAGR (2019-2023)



Notes: See page 48 for data on sales AAGR by customer class.

- While total U.S. retail electricity sales grew by 0.4% per year from 2019-2023, state-level trends are quite varied
- More than half of all states saw declining load over that period
  - Those states with the greatest declines in retail sales also had relatively high growth rates in retail electricity prices (CA, HI, NY, PA, MD, IL)
- In contrast, 7 states saw load growth of more than 2% annually
  - ND stands out with a 7% annual growth rate, largely due to data centers, contributing to the decline in average prices shown previously (see page 28 case study on significant load growth)

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Case Study: Significant load growth for some utilities

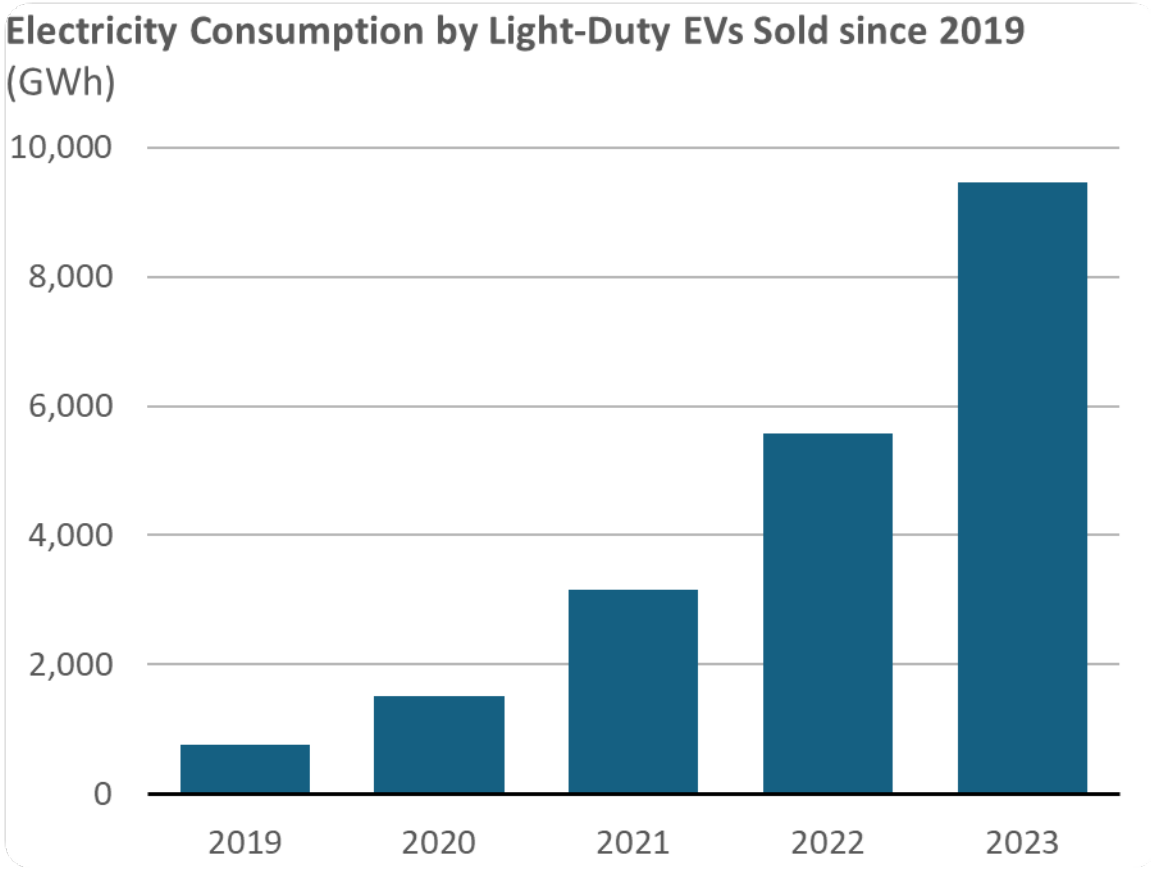
Many utilities in the US have experience annual growth in electricity sales consistently below 1% for the last two decades. From 2003-2023, total U.S. electricity sales grew by 10.5%, for an AAGR of 0.51% (EIA 2024a).

However, some utilities have seen a dramatic increase in load growth in recent years and/or are forecasted to see significantly higher growth in the near-term. The table at right shows the ten highest public- and investor-owned utility AAGRs from 2019-2023 and 2019-2023 difference by GWh. Most utilities in the table experienced AAGRs greater than 10% per year.

Utilities and grid operators consistently point to two primary drivers for this growth: data centers and advanced manufacturing. Data centers in Oregon, Florida, North Dakota, Virginia, and Texas led directly to the high growth rates observed for several of the utilities in the table at right.

Top 10 Utilities for Recent Load Growth by %			Top 10 Utilities for Recent Load Growth by GWh		
Utility Name	State	2019-2023 AAGR	Utility Name	State	2019-2023 Difference
Umatilla Electric Coop Assn	OR	24%	Florida Power & Light Co	FL	15,566,890
Mountrail-Williams Elec Coop	ND	21%	Virginia Electric & Power Co	NC	10,151,705
Chugach Electric Assn Inc	AK	16%	Northern Virginia Elec Coop	VA	4,253,322
Nodak Electric Coop Inc	ND	15%	Umatilla Electric Coop Assn	OR	4,059,325
Northern Virginia Elec Coop	VA	15%	Arizona Public Service Co	AZ	3,525,735
City of Denton	TX	14%	MidAmerican Energy Co	IA	3,414,578
Dalton Utilities	GA	14%	Mountrail-Williams Elec Coop	ND	3,053,913
Montana-Dakota Utilities Co	ND	10%	Salt River Project	AZ	2,986,146
Bluebonnet Electric Coop, Inc	TX	10%	Southwestern Public Service Co	NM	2,407,301
Berkeley Electric Coop Inc	SC	9%	Entergy Texas Inc.	TX	2,156,381

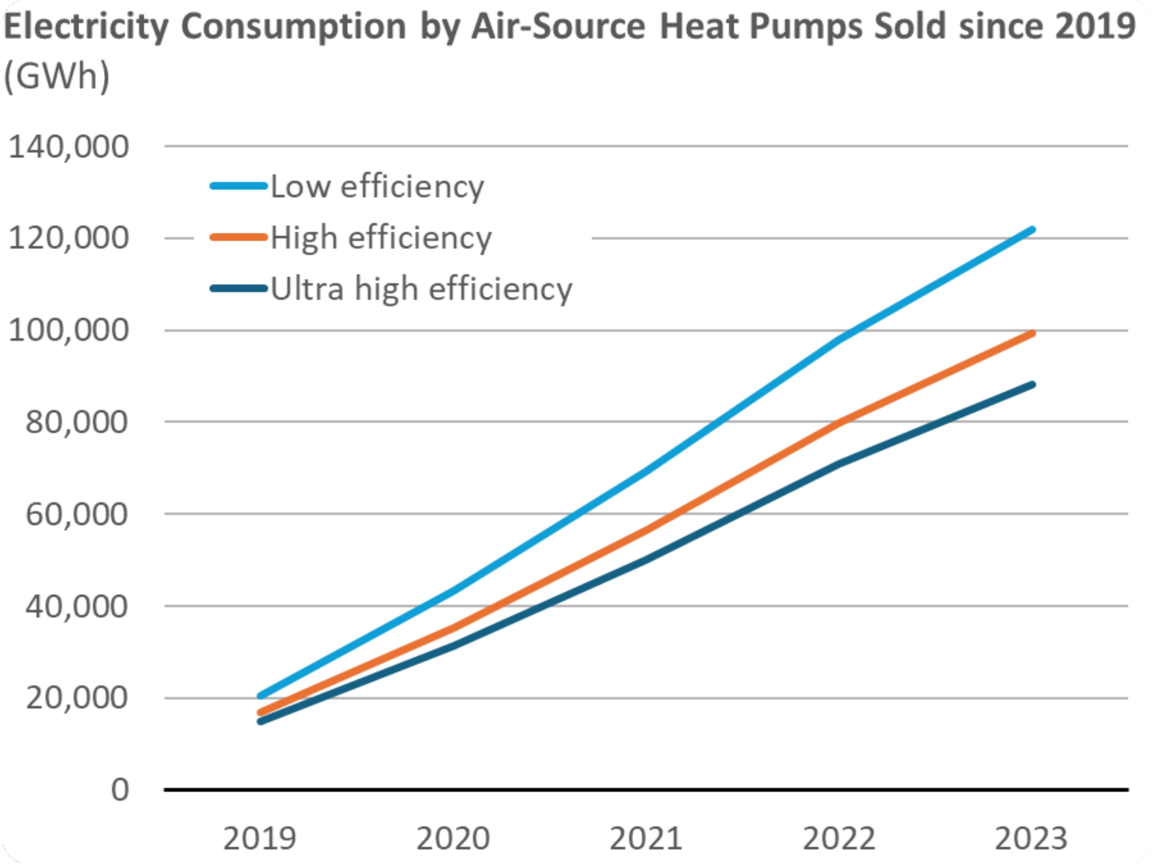
Load Impacts from Electric Vehicles



Notes: Electricity consumption estimates are based on make and model-specific battery size and estimated range. Vehicle miles traveled (VMT) assumptions are based on the midpoint between Zhao et al. (2023) and the median plug-in and hybrid electric VMT reported in the 2022 National Household Travel Survey.

- Light-duty electric vehicle (EV) sales increased from 325,000 vehicles sold in 2019 to 1.4 million in 2023, representing 16% of new vehicle sales sold in 2023 (EIA 2024b)
- Corresponds to roughly 10,000 GWh of added retail electricity consumption (sales) from light-duty EVs sold over the past 5 years
  - Including historical sales of medium- and heavy-duty EVs would add further to those totals
- Annual EV electricity sales accelerated over that timeframe, with roughly a 4,000 GWh of increased electricity consumption from light-duty EVs sold in 2023 alone

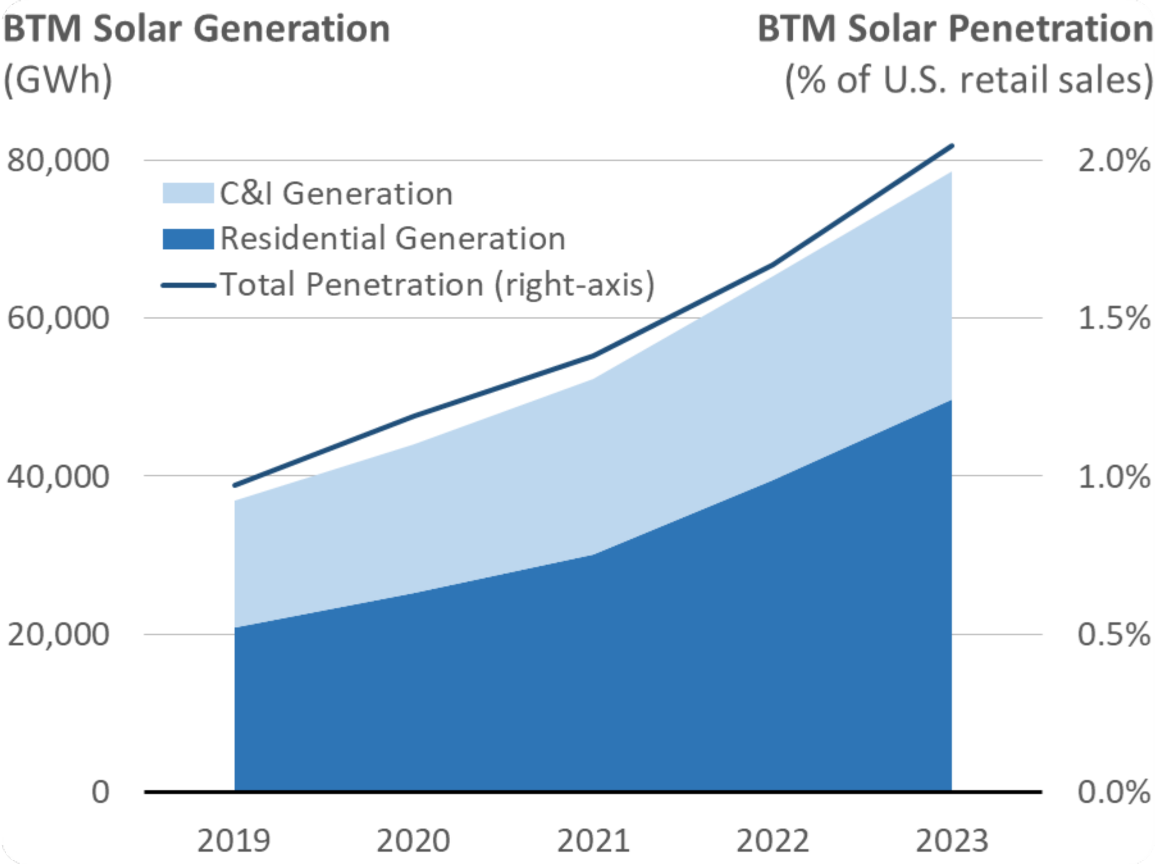
Load Impacts from Air-Source Heat Pumps



Notes: Estimates of low efficiency, high efficiency, and ultra high efficiency heat pump consumption are from the NREL ResStock 2024.2 dataset release for packages 1, 2, and 3, respectively.

- More than 3.6 million air-source heat pumps were sold in the U.S. in 2023, which is a 16% increase from 2019
- Electricity consumption by air-source heat pumps sold from 2019-2023 totals between 88,000 and 120,000 GWh, depending on the efficiency level of the units sold
- Net impact on retail electricity sales depends on the extent to which new heat pumps are replacing fossil-based heating equipment (increasing electricity sales) vs. existing, less efficient electric heating equipment (reducing electricity sales)

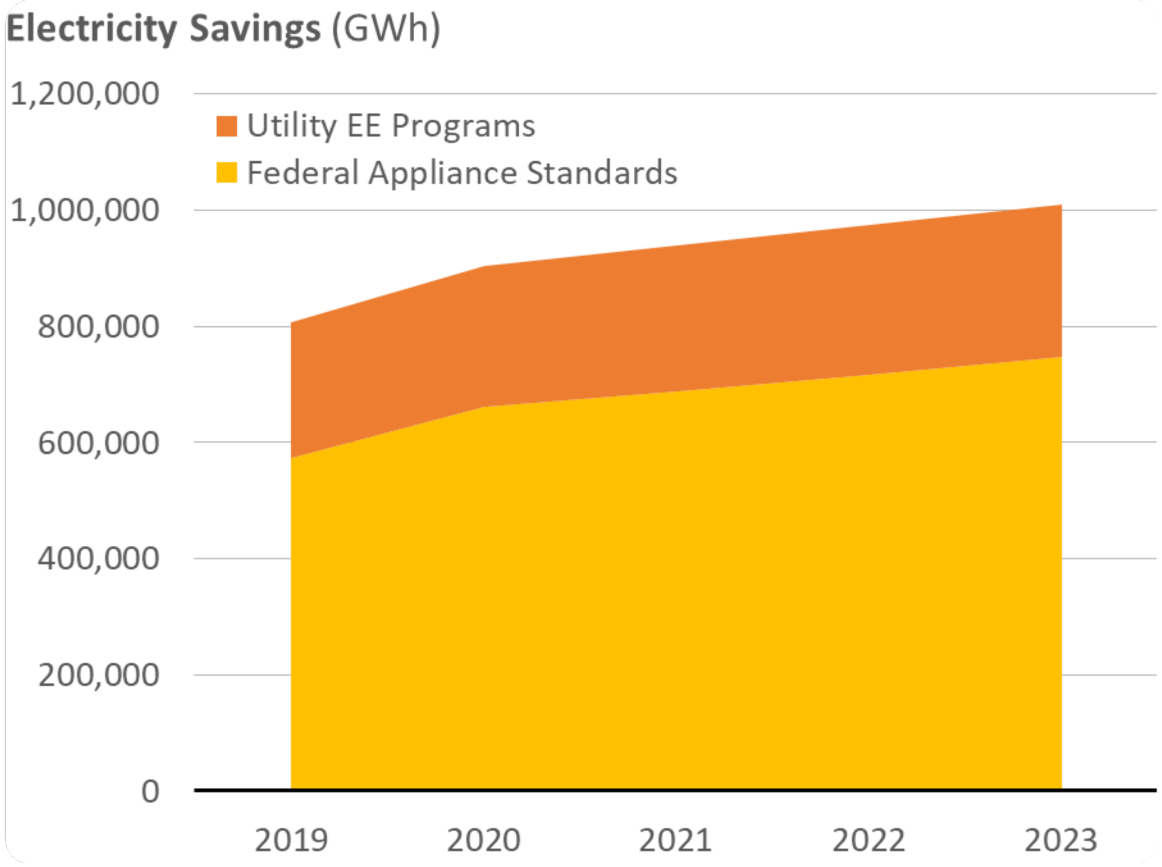
Load Impacts from Behind-the-Meter Solar Growth



Source: EIA 861m and EIA 860

- Depending on the net metering structure, behind-the-meter (BTM) solar generation typically represents a one-for-one displacement of retail electricity sales (i.e., reduction in load)
- BTM solar generation grew by roughly 40,000 GWh from 2019-2023, reaching roughly 2% of sales
- Equates to roughly a 40% reduction in retail sales growth over this period
- Residential solar represent about 70% of total BTM solar growth

Load Impacts from Energy Efficiency Programs and Standards



Notes: Values represent net load reduction in each year from relevant efficiency measures implemented to-date. Estimates account for savings decay over time from measures implemented in prior years.

- Electricity savings from utility ratepayer-funded energy efficiency (EE) programs and federal appliance efficiency standards grew by roughly 250,000 GWh from 2019-2023
- Represents more than 4x total realized retail electricity sales growth over that time period
- More than 80% of that growth in savings is associated with federal appliance efficiency standards
- Additional energy savings (not shown here) generated from other sources, including state building efficiency standards and “naturally occurring” efficiency improvements

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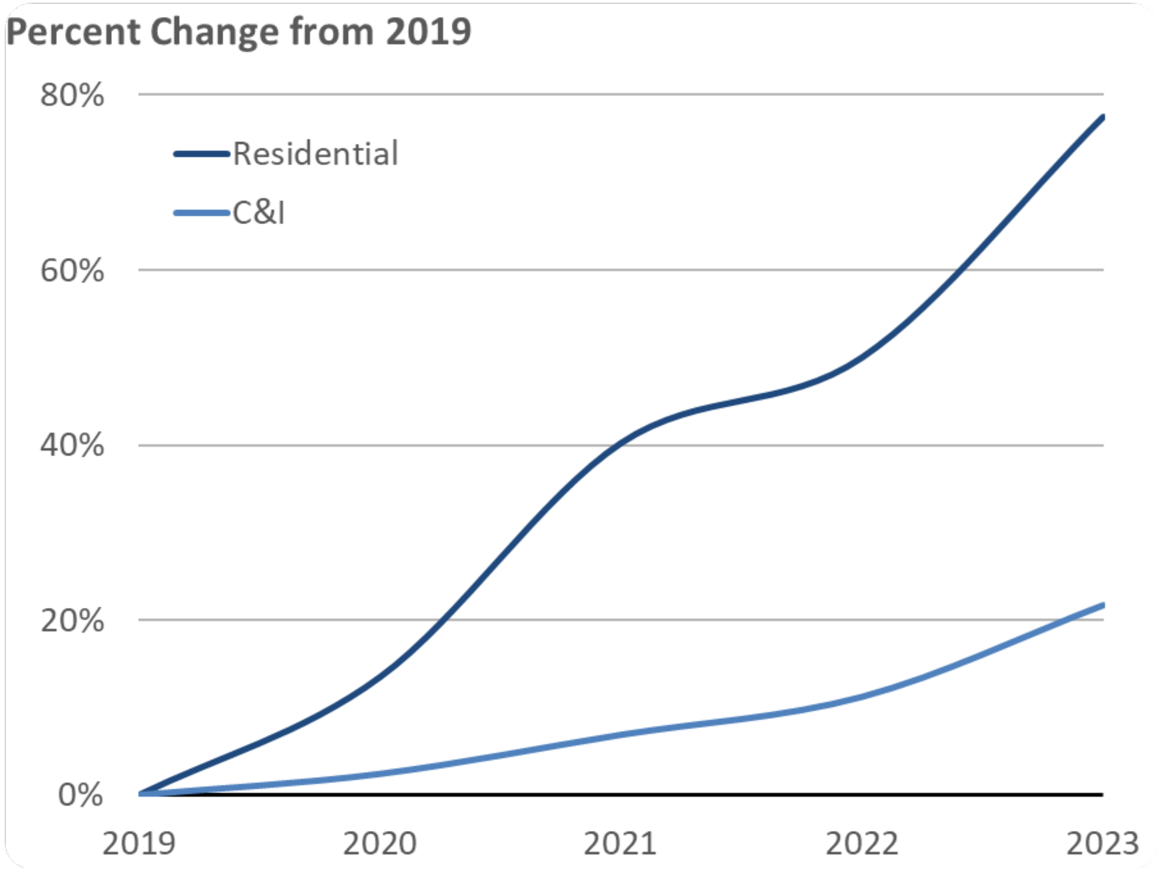
Customer Enrollment in Time-Varying Rates



Source: EIA 861

- The intent and design of time-based rates is to encourage load shedding and shifting that puts downward pressure on growth in electricity costs and retail electricity prices over the long-run
- In aggregate, residential customer enrollment in time-based pricing (including time-of-use and critical peak pricing) has increased almost 80% from 2019 to 2023
- Commercial customer enrollment has also increased steadily and more than 20% higher in 2023 than 2019
- In 2023, more than 10% of all residential customers and more than 11% of all C&I customers were enrolled in time-varying rates nationwide

Case Study: Default residential time-of-use rates

Notable State 2023 TOU Enrollment		
State	**Residential Customer Enrollment (%)**	**C&I Customer Enrollment (%)**
Arizona	37%	6%
California	30%	69%
Colorado	37%	8%
Delaware	57%	7%
Maryland	47%	3%
Michigan	37%	39%
Missouri	44%	2%
Oklahoma	33%	3%

Time-of-Use (TOU) rates vary the price of electricity at different times of the day and are intended to more closely match hourly differences in utility costs compared to average electricity rates. TOU rates incentivize customers to shift their energy consumption from peak to off-peak hours, reducing demand on the grid during peak hours and helping to reduce overall energy costs and emissions (Satchwell et al., 2019).

Since 2019, several states and utilities have implemented *default* residential TOU rates and moving all residential customers to TOU rates unless they opt out. The change is motivated by decades of smaller scale pilot programs and voluntary enrollment that demonstrated bill savings for customers able to change their electricity consumption in response to changing prices (Satchwell et al., 2019). Increased deployment of advanced metering infrastructure and "smart meters" that can measure household hourly electricity consumption has further enabled TOU rates (Colorado Department of Regulatory Agencies, 2022).

Notable examples of TOU rates include Arizona Public Service and Oklahoma Gas and Electric with long-standing TOU rate offerings and Xcel Energy in Colorado that implemented a default residential TOU rate in 2022. Other examples include California (in 2019) and Michigan (in 2023) that ordered their investor-owned utilities to default residential customers to TOU rates.

Conclusion

Key Takeaways

- U.S. average retail electricity prices increased 4.8% per year from 2019 to 2023 on a nominal basis and some state average retail electricity prices increased more than 8.0% per year
- Taking inflation into account, U.S. average retail electricity prices were mostly flat between 2019 and 2023, though have been rising faster than inflation for residential customers
- Most categories of utility costs increased from 2019 to 2023, and especially for distribution CapEx that grew by 50% - more than double the rate of inflation
- Retail electricity sales remained nearly flat from 2019 to 2023 and was not a major driver of cost-growth in recent years at the national level, though some states and utilities experienced significant load growth due to new data centers and industrial facilities
- Customer investments in behind the meter resources grew and had varying impacts on retail electricity sales: On an absolute basis, energy efficiency load impacts grew the most by roughly 250,000 GWh from 2019 to 2023 and, on a percentage basis, electric vehicle load impacts grew the most at more than 400% from 2021 to 2023

Potential Data Needs and Future Research Areas

- Future updates to this report could aim to address important data gaps:
  - More granular data on distribution system costs, including wildfire mitigation costs
  - State or utility-level data on heat pump and EV sales
  - Data on the efficiency of new heat pump sales and what technologies were replaced
  - Data on programmatic costs for utility ratepayer-funded programs (for EE, DR, etc.)
- Potential research areas to further explore:
  - Decomposing retail rate increases into underlying drivers
  - Estimating the impact of new sources of load growth (data centers, manufacturing) on retail electricity prices
  - Estimating the impact of BTM resources on retail electricity prices, and the efficacy of strategies for mitigating those impacts (e.g., managing EV charging, deploying heat pumps in combination with building efficiency or in locations to avoid natural gas system costs)
  - Estimating the impact of rate structures (e.g., TOU) on overall retail electricity prices and utility costs

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Appendix

FERC Form 1 Coverage

State	Gen. CapEx	Transm. CapEx	Dist. CapEx	Other CapEx	Gen O&M	Transm. O&M	Dist. O&M	Other O&M	FPP
AK	1	2	2	2	2	2	2	2	2
AL	1	1	1	1	1	1	1	1	1
AR	1	1	1	1	1	1	1	1	1
AZ	3	3	3	3	3	3	3	3	3
CA	2	2	2	1	2	2	2	2	2
CO	2	2	2	2	2	2	2	2	2
CT	0	2	2	2	0	2	2	2	2
DC	0	1	1	1	0	1	1	1	1
DE	0	2	2	2	0	2	2	2	2
FL	3	3	3	3	3	3	3	3	3
GA	0	1	1	1	1	1	1	1	1
IA	2	1	2	2	2	2	2	2	2
ID	1	1	1	1	1	1	1	1	1
IL	0	1	1	1	0	1	1	1	1
IN	4	4	4	4	4	4	4	4	4
KY	3	3	3	3	3	3	3	3	3
LA	4	4	3	4	4	4	4	4	4
MA	1	3	3	3	2	3	3	3	3
MD	0	2	2	2	1	2	2	2	2
ME	0	1	1	1	0	1	1	1	1
MI	2	0	3	3	3	3	3	3	3
MN	3	3	3	3	3	3	3	3	3
MO	2	3	3	3	2	3	3	3	3
MS	2	2	2	2	2	2	2	2	2

State	Gen. CapEx	Transm. CapEx	Dist. CapEx	Other CapEx	Gen O&M	Transm. O&M	Dist. O&M	Other O&M	FPP
NC	2	1	2	2	2	2	2	2	2
ND	1	1	1	1	1	1	1	1	1
NH	0	1	2	2	0	2	2	2	2
NJ	1	2	2	2	0	2	2	2	2
NM	1	1	1	1	1	1	1	1	1
NV	2	2	2	2	2	2	2	2	2
NY	4	7	7	7	5	7	7	7	7
OH	2	7	9	9	4	9	9	9	9
OK	2	2	2	2	2	2	2	2	2
OR	2	2	2	2	2	2	2	2	2
PA	0	4	6	6	0	6	6	6	6
RI	0	1	1	0	0	1	1	1	1
SC	2	2	2	2	2	2	2	2	2
SD	2	2	2	2	2	2	2	2	2
TN	0	1	1	1	0	1	1	1	1
TX	3	5	5	5	3	5	5	5	3
UT	0	0	0	1	1	1	1	1	1
VA	2	2	2	2	2	1	2	2	2
VT	1	1	1	1	1	1	1	1	1
WA	2	2	2	2	2	2	2	2	2
WI	7	3	7	7	8	8	8	8	8
WV	1	1	1	1	1	1	1	1	1
WY	1	1	1	1	1	1	1	1	1

Notes: Numbers show the count of utilities in 2023 for each state and cost category to better understand the level of coverage for each cost category and state. All but 3 utilities included in this analysis (across all categories) are investor-owned. In total, there are 172 investor-owned utilities (of 207 total) that reported FERC Form 1 data in 2023. Within this sample, there are no utilities represented in Hawaii, Kansas, Montana, and Nebraska.

FERC Form 1: Total Reported Spending in 2023

	Number of utilities reporting	2023 Total Spending ($B)
Generation CapEx	75	$19.0
Transmission CapEx	99	$20.0
Distribution CapEx	112	$47.4
Other CapEx	112	$10.8
Generation O&M	84	$14.0
Transmission O&M	114	$15.9
Distribution O&M	115	$17.2
Other O&M	115	$35.3
FPP	113	$94.3

- Spending values in the table provide a rough sense of the relative size of spending in each category, but cannot be directly compared to one another, because of the different set and number of reporting utilities for each category. For this reason, the report focuses on percentage change (as opposed to absolute change) over time to better compare.

- Costs included in "Other" categories:

  Other CapEx (FF1, pg. 204): Land and land rights, structures and improvements, fuel holders products and accessories, prime movers, generators, accessory electric equip, asset retirement costs for other production

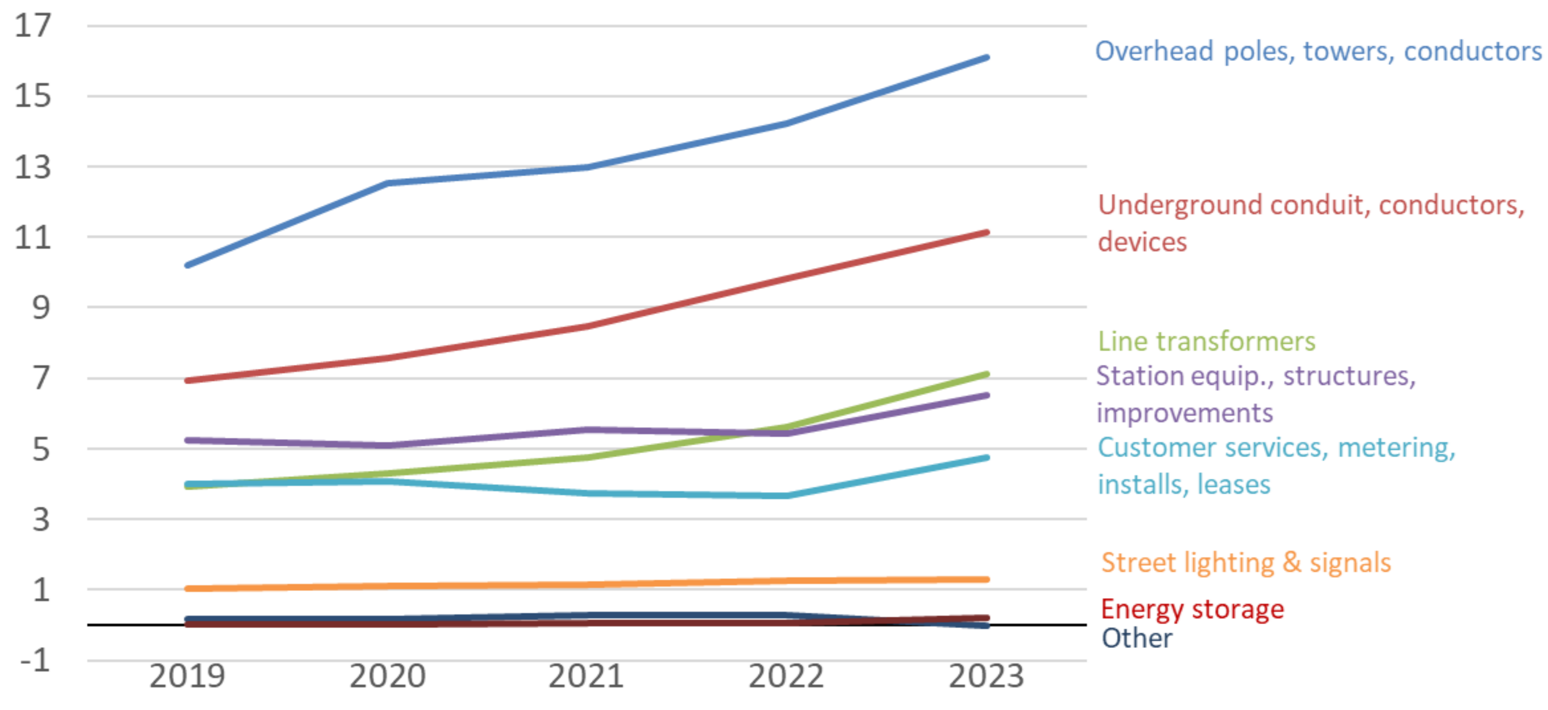
  Other O&M (FF1, pg 322-323): Regional market expenses incl. operation supervision, market facilitation monitoring and compliance, rents, computer maintenance and equipment; Customer accounts expenses incl. supervision, meter reading, collections; Customer service and informational expenses; Sales expenses; Administrative and general expenses incl. salaries, office supplies, property insurance, injuries and damages, employee benefits, franchise requirements, advertising, rent

Absolute values for O&M, CapEx, Fuel, and Gas Prices

		2019	2020	2021	2022	2023
CapEx	Generation [$B]	28.5	21.6	17.5	18.9	19.0
	Transmission [$B]	16.8	19.7	18.9	18.3	19.9
	Distribution [$B]	31.5	34.8	36.8	40.3	47.4
	Other [$B]	7.8	7.3	9.2	9.9	10.8
O&M	Generation [$B]	15.1	13.6	13.8	14.7	14.0
	Transmission [$B]	13.7	13.7	15.2	15.9	15.9
	Distribution [$B]	13.9	15.8	16.1	17.1	17.2
	Other [$B]	39.5	31.1	30.4	32.7	35.3
Misc.	CPI [index]	254	257	266	288	302
	FPP [$B]	73.5	68.2	86.5	118.4	94.3
	Henry Hub Gas [$/MMBTU]	2.56	2.03	3.89	6.45	2.53

Distribution Capital Expenditures by Functional Categories

Distribution Capital Expenditures 2019 to 2023 (Billion $)



Notes: "Other" includes land rights and asset retirement. Source: FERC Form 1

- ☐ Within the distribution capital expenditure category, overhead equipment is consistently the largest cost category, followed by underground equipment; both increased from 2019 to 2023
- ☐ Line transformers is the only other cost category with growth over the entire study period
- ☐ All other categories have seen relatively flat spending from 2019-2023 with the exception of station equipment and customer services, which have only seen growth in recent years

Operation & Maintenance Expenditures by Region

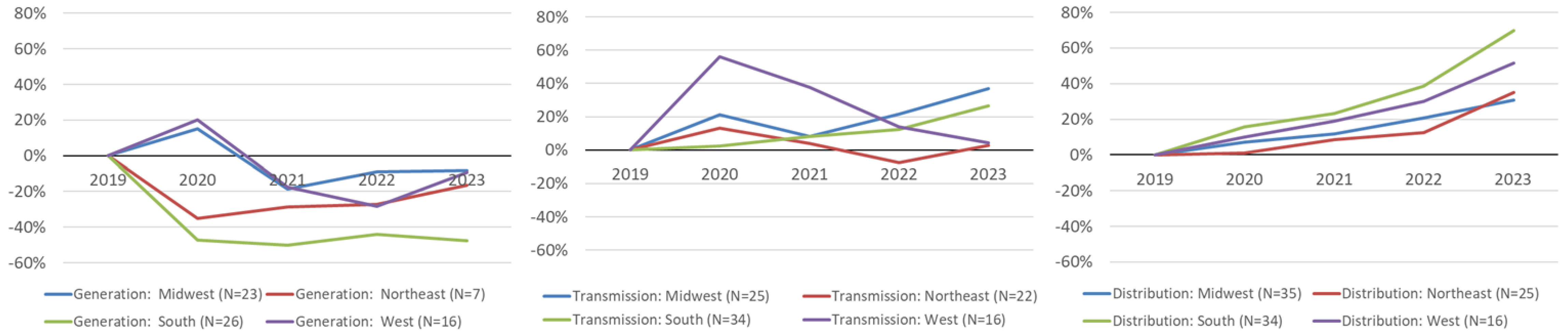
Percent Change in O&M Expenditures from 2019

Notes: Figure shows percent change in nominal O&M from 2019 values for each O&M category and Census region. N values indicate utility count for each. Source: FERC Form 1

- Generation O&M growth has been modest in all regions (roughly +/-10% change since 2019)
- The West stands out in terms of distribution O&M growth (60% since 2019, compared to 0-20% in other regions)
- Transmission O&M grew by 20% in all regions, except the West, where it remained flat

Capital Expenditures by Region

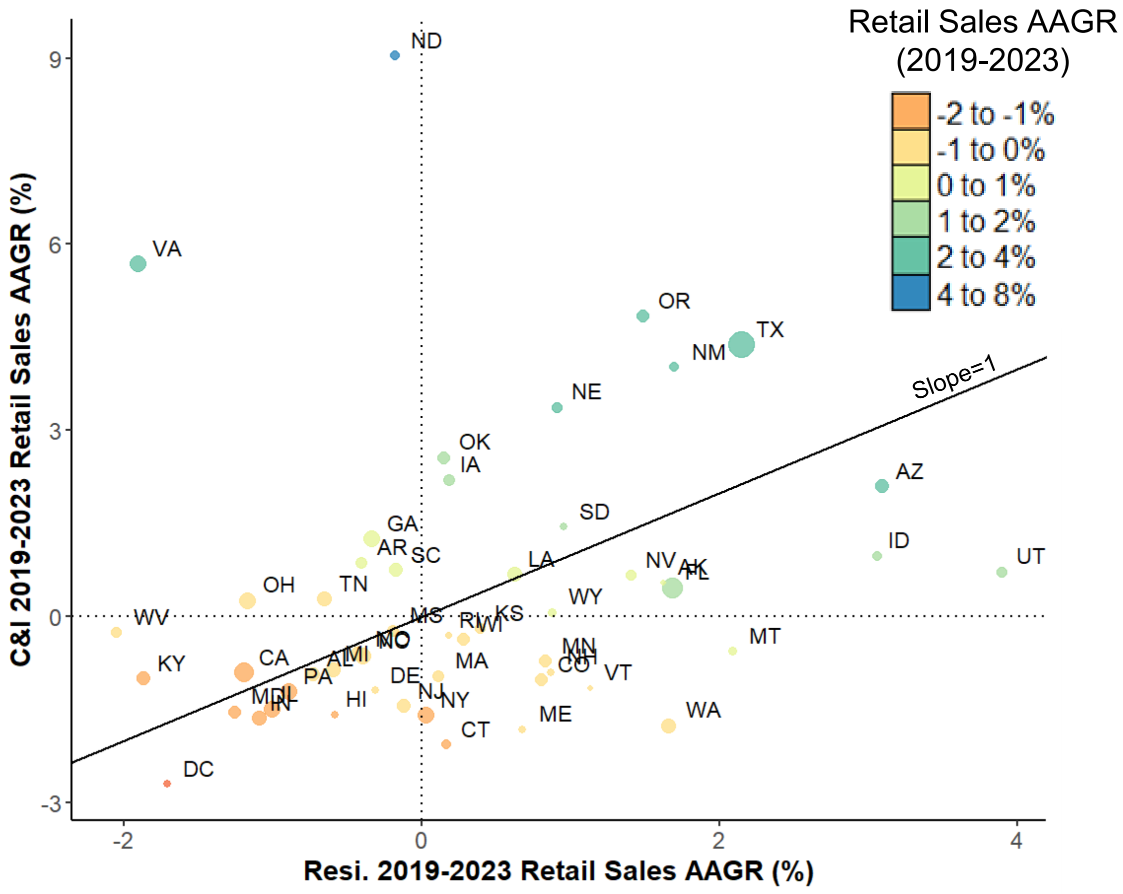
Percent Change in CapEx from 2019



Notes: Figure shows percent change in nominal CapEx from 2019 values for each CapEx category and Census region. Values represent annual additions. N values indicate utility count for each. Source: FERC Form 1

- Generation CapEx (left panel) in all regions has declined since 2019, though can be volatile year-to-year, reflecting lumpiness of these costs
- Transmission CapEx (middle panel) growth also tends to be volatile from year-to-year, with the South and Midwest seeing the steadiest growth
- Distribution CapEx (right panel) steadily rose across regions, addressing needs related to aging infrastructure, increasing demand, reliance and resilience needs, and/or system upgrades to accommodate DERs

Retail Sales AAGR by Customer Class and State



Notes: Colors correspond to those on page 25 and reflect AAGR for total retail sales (with cool colors for positive AAGR and warm colors for negative AAGR).

- State-level C&I growth rates over the 2019-2023 period were more varied than residential growth rates, ranging from a roughly -3% to +9% AAGR, compared to -2% to +4% for residential
- Residential growth rates exceeded C&I growth rates in most (33) states (i.e., below the diagonal line in the figure)
- Contrasts with national trends, where total U.S. C&I growth rate was higher than residential
- Relatively high U.S. C&I growth rates were driven by robust growth in a handful of states—as described earlier, tied to growth key industrial sectors (e.g., data centers, oil & gas)

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