

AN EXAMINATION OF RISING ELECTRICITY COSTS AND RATES IN CALIFORNIA

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EXECUTIVE SUMMARY

There is growing consensus that California's electricity rates and costs are too high, but there is less consensus about why and what to do about them.

Between 2000 and 2024, California's real (inflation-adjusted) electricity rates rose by more than 50%. Before 1974, electricity rates in California were lower than the U.S. average; in 2024, they were more than double the U.S. average.

This paper examines the history of electricity rate and cost changes in California over the last 25 years. It aims to support a broader conversation on solutions that stabilize and reduce electricity costs and rates in the state.

The paper is organized into three sections:

1. **Trends in Average Real Electricity Rates** reviews California's average electricity rates relative to the U.S. average from 1970 to 2024,
2. **Trends in Investor-Owned Utility Costs** reviews of annual costs (revenue requirements) for the state's three main utilities from 2003 to 2024, and
3. **Conclusions** identifies priority areas for discussion, drawing on the reviews.

The paper shows that the divergence between California and U.S. average electricity rates has proceeded in fits and starts since the 1980s, with different drivers in different periods — high-priced qualifying facility contracts and nuclear cost overruns in the 1980s and 1990s, an electricity crisis in the early 2000s, rising costs and declining sales from 2010 to 2018, and, more recently, increased costs from wildfire mitigation. While some of the upward pressure on California's average rates came from declining sales, the largest driver of rate increases has been a large and sustained increase in costs.

There is no single cost component or cost driver that explains rising costs.

- ▶ Real annual **distribution** costs for the three investor-owned utilities (IOUs) nearly doubled between 2003 and 2024 (from \$10.7 to \$19.4 billion per year [2024\$]), though for most of this time period they were relatively flat. Costs increased in a stepwise fashion with increases concentrated in three periods, each of about equal magnitude and each with a different driver: 2008-2011 (advanced meters, smart grid investments), 2020-2022 (wildfire costs), and 2023-2024 (wildfire costs, higher returns on investment).
- ▶ The IOUs' real **transmission** revenue requirements increased steadily and by three-fold between 2007 and 2023 (\$1.8 billion to \$5.7 billion per year [2024\$]), due to a mix of renewable portfolio standard (RPS) driven needs and inadequate federal oversight over local transmission costs.
- ▶ The IOUs' real bundled **generation** rates — still an important benchmark — increased by 40% between 2012 to 2024 (from \$0.10/kWh to \$0.14/kWh [2024\$]) due to a combination of high RPS costs (2012-2014) and load migration-induced sales declines that outpaced generation cost declines (2014-); the latter was likely a result of the IOUs' long-term contractual obligations (RPS, resource adequacy, qualifying facilities) and, relatedly, California's unfinished retail sector reforms.

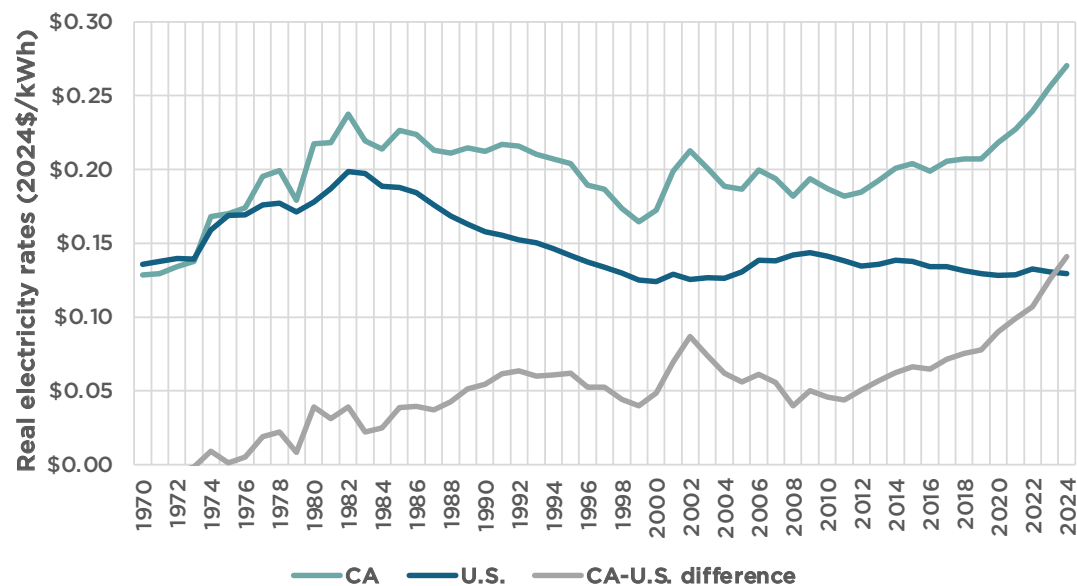
How can California's electricity costs and rates be stabilized and reduced over time? Drawing on the reviews, the paper identifies several areas to help frame discussion around possible solutions.

- ▶ **Cost transparency.** There is still disagreement over why California's electricity costs and rates are so high and whether they should go even higher. *What benchmarks, metrics, and goals would better align expectations of what costs and rates should be?*
- ▶ **Near and longer-term focus.** Tackling the root causes of high costs and rates will require multiple solutions — to address multiple causes — and sustained policy focus over time. *Which solution areas should be prioritized, both in the near term when costs, policies, and politics tend to be fixed and in the longer term when they are more malleable?*
- ▶ **Policy and regulatory simplification.** A key challenge in finding and sustaining the focus to tackle high costs is that California's electricity sector is overly complex — in its policies, regulation, accounting, planning, and programs. *What kinds of steps could help to meaningfully simplify the state's electricity sector?*
- ▶ **Wildfire costs.** Wildfire costs are now an unsustainably large part of IOU revenue requirements (10-27%). *What level of utility wildfire mitigation is socially optimal and how should mitigation costs be regulated?*
- ▶ **More efficient infrastructure use.** High transmission and distribution costs are partly due to declining load factors and generator siting and storage decisions. *What changes to interconnection, resource planning, transmission planning, programs, and prices would help to encourage more efficient infrastructure use?*
- ▶ **Retail reform.** California's retail sector lacks a coherent, long-term vision that defines the roles and responsibilities of the state, the IOUs, and unregulated providers. *How can the state come up with a vision for longer-term retail reform, given its political sensitivity and complexity?*
- ▶ **NEM reform.** NEM has some impact on average costs and rates, but its main impacts are distributional via cost shifts. *What are politically feasible approaches to reforming NEM, and what should the end goal be?*
- ▶ **Transmission cost oversight.** Utility self-approved transmission costs lack federal or state oversight. *How can federal and state regulators track and set incentives for these costs to encourage prudence?*

1 TRENDS IN AVERAGE REAL ELECTRICITY RATES

Prior to 1974, average electricity costs in California were lower than the U.S. average, but since then electricity costs have risen much faster in California than in most of the U.S. (Figure 1) In 2024, California's average electricity costs were more than double the U.S. average.

FIGURE 1. *California and U.S. Average Real Electricity Rates and California-U.S. Differences, 1970-2024*



Sources and notes: U.S. average includes California. All rates were deflated using U.S. consumer price index data from the Bureau of Labor Statistics. Data are from the U.S. Energy Information Administration (EIA), <https://www.eia.gov/electricity/data/state/>.

This divergence in electricity costs between California and the U.S. occurred in fits and starts — in fact, during parts of the 1990s and 2000s, electricity costs in California rose more slowly than in most of the U.S. The four periods with the most rapid average cost increases in California, relative to the U.S. average, include:

- ▶ 1980-1992 – high-priced qualifying facility (QF) contracts and nuclear cost overruns
- ▶ 2000-2002 – California's electricity crisis
- ▶ 2010-2018 – rising costs and declining sales
- ▶ 2018-present – adapting to wildfires

The first period (1980-1992) followed the aftermath of the oil crises of the 1970s and saw the three main investor-owned utilities (IOUs) locked into high-priced, long-duration QF contracts and, to

a lesser extent, nuclear projects that ran behind schedule and above estimated cost.¹ It spurred the development of a flawed electricity market in which the IOUs were overly exposed to high spot market prices during 2000 and 2001, bankrupting one of the IOUs and compelling the state to intervene and sign high-priced, long-term power contracts through the Department of Water Resources (DWR) in order to stabilize generation costs.²

In the wake of the electricity crisis, average electricity costs in California steadied and declined in real terms, narrowing their gap with the U.S. average. Beginning in the early 2010s, electricity costs rose across generation, transmission, and distribution functions (see next section), while sales fell due to a combination of rapid growth in behind-the-meter solar PV, energy efficiency improvements, and economic and demographic change, leading to an increase in average costs.³ Utility spending on wildfire prevention after the Camp Fire in 2018 explains much of the large increase in average costs in California relative to the U.S. from 2018 to 2024.

2 TRENDS IN INVESTOR-OWNED UTILITY COSTS

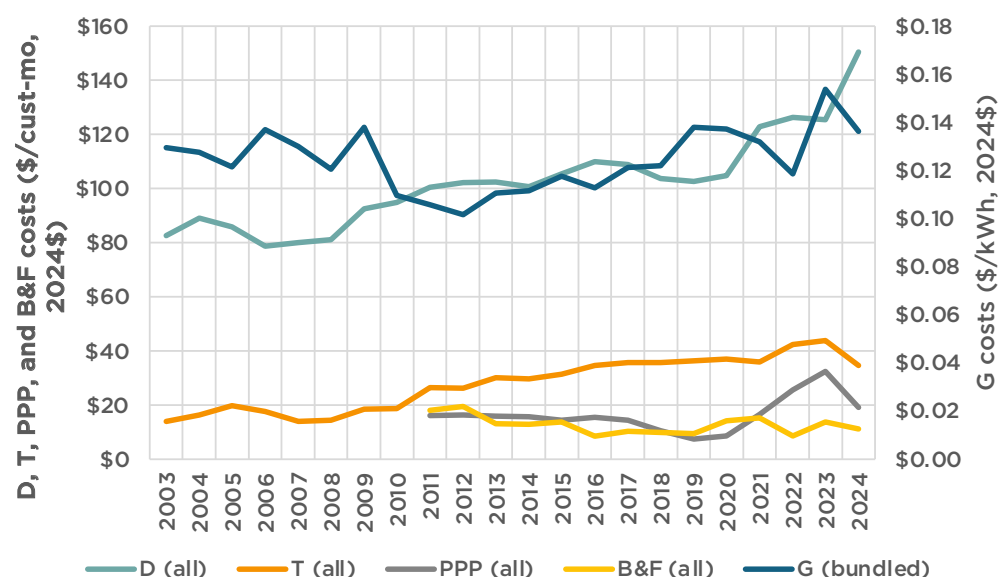
Trends in utility costs by function — generation, transmission, distribution, and other — provide additional insight on changes in California's electricity costs and rates over the last two decades. Figure 2 shows real costs by function for California's three main IOUs from 2003 to 2024. Distribution (D), transmission (T), public purpose programs (PPP), and bond and fee (B&F) costs are in units of real (2024\$) dollars per customer per month (\$/cust-mo) because these costs are largely fixed and are charged to all customers. Generation costs are in (2024\$) dollars per kilowatt-hour (\$/kWh) of utility bundled customer sales. The latter accounts for load migration from utilities to community choice aggregators (CCAs) and other retail providers.

1 In 1998, the U.S. Congressional Budget Office (CBO) estimated that more than 70% of California's above-market (stranded) costs were due to QF contracts. See CBO, 1998, *Electric Utilities: Deregulation and Stranded Costs*, <https://www.cbo.gov/sites/default/files/cbofiles/ftpdocs/9xx/doc976/stranded.pdf>. For a history of this time period, see the CPUC's 1993 *Yellow Book*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/yellow_book.pdf.

2 The three main issues that led the market to fail included high spot market prices, due to a confluence of factors; lack of IOU hedging of those prices, in part but not entirely due to limits on hedging; and frozen IOU retail rates that were intended to encourage load migration and consumer savings. Blumstein et al.'s (2002) excellent history of this time period is still available online at <https://haas.berkeley.edu/wp-content/uploads/csemwp103.pdf>.

3 We discuss growth in behind-the-meter solar PV in the next section. The impact of economic and demographic change on electricity sales in California has not been adequately studied, in our view. As an illustration of these changes, from 2010 to 2018 California's residential and industrial customer sales increased by 2% and 1%, respectively, but commercial sales declines of 4% led to total electricity sales declines of 1%. Data are from EIA, <https://www.eia.gov/electricity/data/state/>.

FIGURE 2. IOU Average Costs by Function, 2003-2024



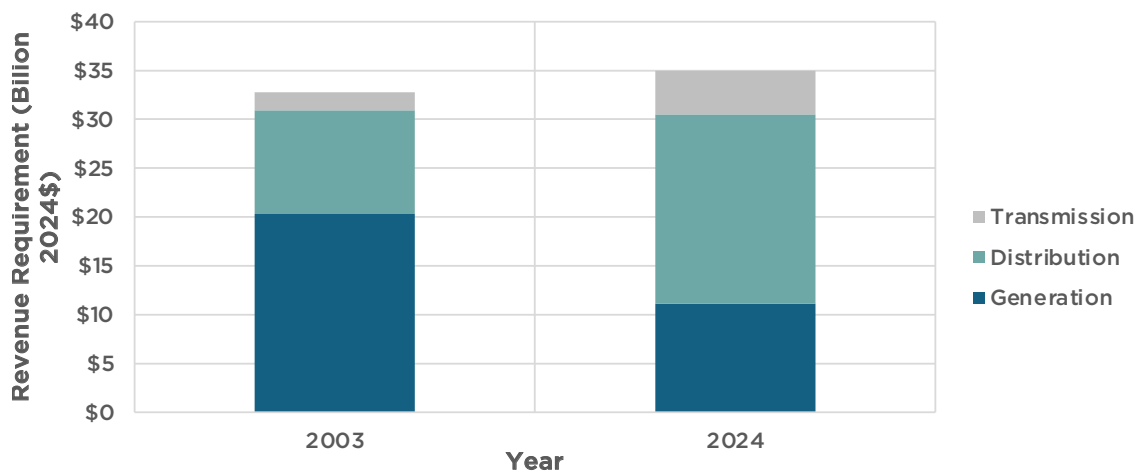
Sources and notes: All cost data is from the CPUC's California Electric and Gas Utility Costs Report ("Costs Report") series.⁴ Data for costs between 2003 and 2010 is only available in figures and we used a superimposed grid to estimate these data from figures. Distribution costs for 2003-2010 did not include taxes. To make 2003-2010 data comparable to recent data, we estimated a tax component of the distribution revenue requirement for these years by estimating the share of distribution taxes in 2011 and applying that share to previous years. Data after 2011 is based on the Electric IOU Authorized Revenue Requirement Components table ("Components table") in the Costs Report. The revenue requirements in this table are directionally similar but different than those in section 1 of the Costs Report, but the report does not explain the differences. We used the data in the Components table to provide a longer, consistent time series of revenue requirements. Data on customers and bundled sales is from the EIA's Form EIA-861 data, <https://www.eia.gov/electricity/data/eia861/>. We deflated costs using the California Department of Finance's Consumer Price Index, <https://dof.ca.gov/forecasting/economics/economic-indicators/inflation/>.

Figure 2 highlights several longer-term trends. First, real per customer distribution costs experienced alternating periods of plateaus (2003-2008, 2011-2020) and steep inclines (2008-2011, 2020-2022, 2023-2024), increasing from \$83/cust-mo in 2003 to \$150/cust-mo in 2024. Real per customer transmission costs rose more steadily over this period, from \$14/cust-mo in 2003 to \$35/cust-mo in 2024. Real per sales generation costs initially fell, from \$0.13/kWh in 2003 to \$0.10/kWh in 2012, then rose to \$0.14/kWh in 2024. Real per customer PPP and bond and fee costs were largely stable or declined from 2011 to 2020. From 2019 to 2023, PPP costs rose fourfold due to wildfire-related costs. Some of these costs appear to have been reclassified as distribution costs in 2024.

As IOU costs and sales shifted over the 2000s and 2010s, so did the structure of their revenue requirements. The IOUs' total revenue requirement for generation, transmission, and distribution increased by 7% (from \$33 to \$35 billion) in real terms (\$2024) between 2003 and 2024, but as Figure 3 shows the relative size and shares of these costs changed significantly. Generation costs fell from \$20 billion to \$11 billion per year in \$2024 (from 62% to 32% of these three costs), primarily due to load migration. Distribution costs rose from \$11 billion to \$19 billion per year in \$2024 (from 33% to 55%). Transmission costs rose from \$2 billion to \$4 billion per year in \$2024 (from 6% to 13%).

4 See <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/reports-on-utility-costs>.

FIGURE 3. IOU Generation, Distribution, and Transmission Revenue Requirements (2024\$) in 2003 and 2024



Sources: See the notes to Figure 2 for the data sources and adjustments used in this figure.

The changes in IOU average costs for generation, transmission, and distribution over the last two decades do not have a simple unifying story. Changes in electricity sales and customer counts were an important driver of average cost changes. Changes in generation, transmission, and distribution costs were often structural or episodic, each with its own story. The next few sections examine each of these components individually.

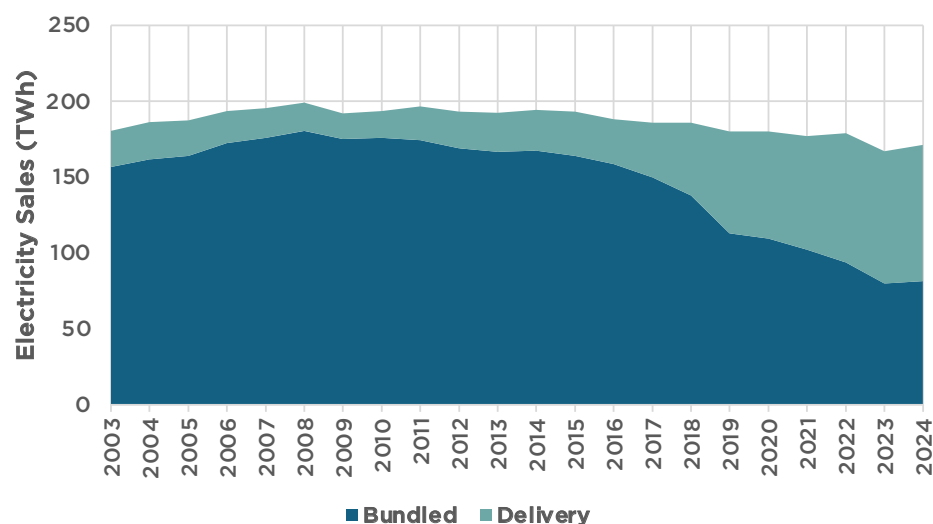
2.1 SALES AND CUSTOMER COUNTS

According to EIA data, the three IOUs' total (bundled plus unbundled) electricity sales increased in the 2000s, flattened after the financial crisis in 2008, and began to decline in the mid-2010s (Figure 4). Declines in total sales are closely linked to, but not fully explained by, growth in behind-the-meter solar PV. Between 2014 and 2024, 1-2% annual growth in sales for the IOUs would have amounted to an additional 22-45 TWh of sales, but instead sales declined by 23 TWh between 2014 and 2024.⁵ Behind-the-meter PV systems generated on the order of 25-30 TWh in 2024, which implies that they may have accounted for most of the decline in sales between 2014 and 2024 (23 TWh) but not the decline in sales growth (22-45 TWh) during this time period.⁶

⁵ In 2024, total IOU sales were 194 TWh. At 1-2% annual average growth from 2014-2024, sales would have been 215-237 TWh in 2024.

⁶ In 2024, California had 16.1 GW of behind-the-meter PV generation. At a capacity factor of between 0.18 and 0.20, these systems would have generated 25-28 TWh in 2024. The trend in flattening sales growth predates growth in rooftop PV and, to our knowledge, does not have a rigorous explanation. PV capacity data are from <https://www.californiadgstats.ca.gov/>.

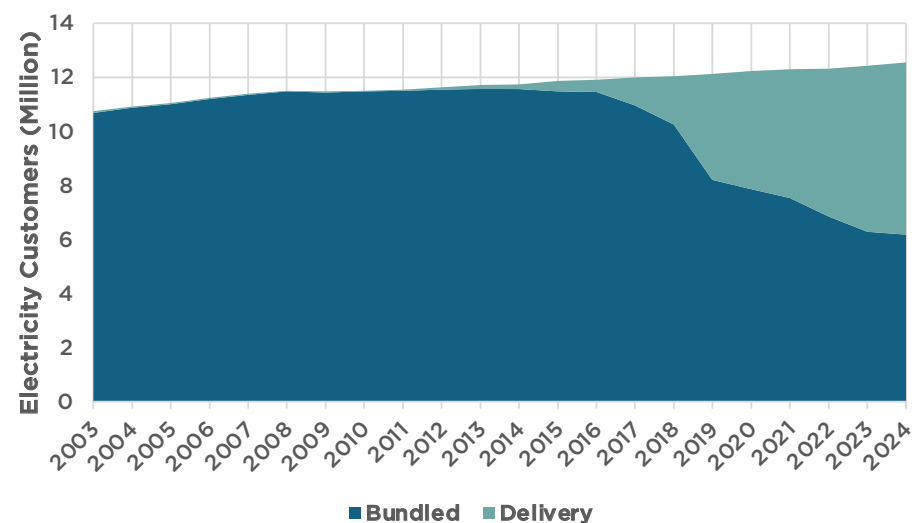
FIGURE 4. IOU Electricity Sales to Bundled and Delivery-Only Customers, 2003-2024



Source: See the notes to Figure 2.

The three IOUs' customer counts grew at 1.4% per year until 2008 and then grew at only 0.7% per year between 2009 and 2023 (Figure 5). It is unclear if this change is related to economic changes after the recession in 2008 or due to data anomalies. Slower growth in customers contributed to higher per customer costs in Figure 2.

FIGURE 5. IOU Bundled and Delivery-Only Customer Counts, 2003-2024



Source: See the notes to Figure 2.

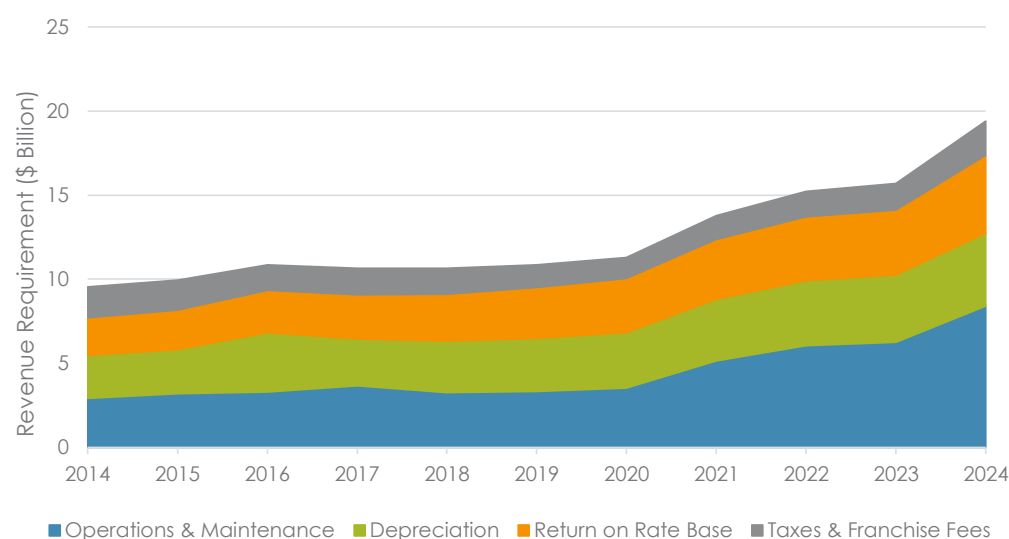
Both Figures 4 and 5 clearly show the large migration of IOU customers to CCAs and other non-utility retail providers beginning in 2017. Load migration affects the IOUs' average generation costs because unbundled customers that leave the IOUs' retail service no longer contribute to the IOUs' recovery of fixed generation costs. However, it does not affect the IOUs' average distribution and transmission costs, because the IOUs continue to charge unbundled customers for their use of the grid through their retail providers.

2.2 DISTRIBUTION COSTS

Distribution revenue requirements may include a variety of costs that are unrelated to providing distribution service but are included in “distribution” to ensure that both bundled and delivery-only customers are not able to bypass them. This paper did not do a deeper investigation of distribution line items to better understand what is included in the IOUs’ distribution costs. However, the structure of distribution costs is not immediately intuitive. Since at least 2003, depreciation costs (capital investment) have been a smaller share of the distribution revenue requirement than O&M costs (Figure 6 and Figure 7).

The three largest increases in distribution costs (2008-2011, 2020-2022, 2023-2024) had different drivers. The \$2.5 billion (2024\$) increase in real distribution costs from 2008-2011 was driven by capital spending (Figure 7), which appears to have coincided with IOU smart meter and smart grid investment programs.⁷ The \$2.8 billion increase in costs from 2020-2022 was driven by O&M costs, which was mainly due to increased spending on vegetation management and wildfire insurance.⁸ The \$3.2 billion increase in costs from 2023-2024 was driven by O&M costs and, to a lesser extent, an increase in returns and corresponding corporate income taxes, though part of the increase appears to have been a re-classification of costs from PPP to distribution.⁹ Together, the cost increases during these three time periods — 2008-2011, 2020-2022, and 2023-2024 — accounted for 97% of the increase in the IOUs’ real annual distribution revenue requirements between 2003 and 2024.

FIGURE 6. *Nominal IOU Distribution Costs by Cost Component, 2013-2024*



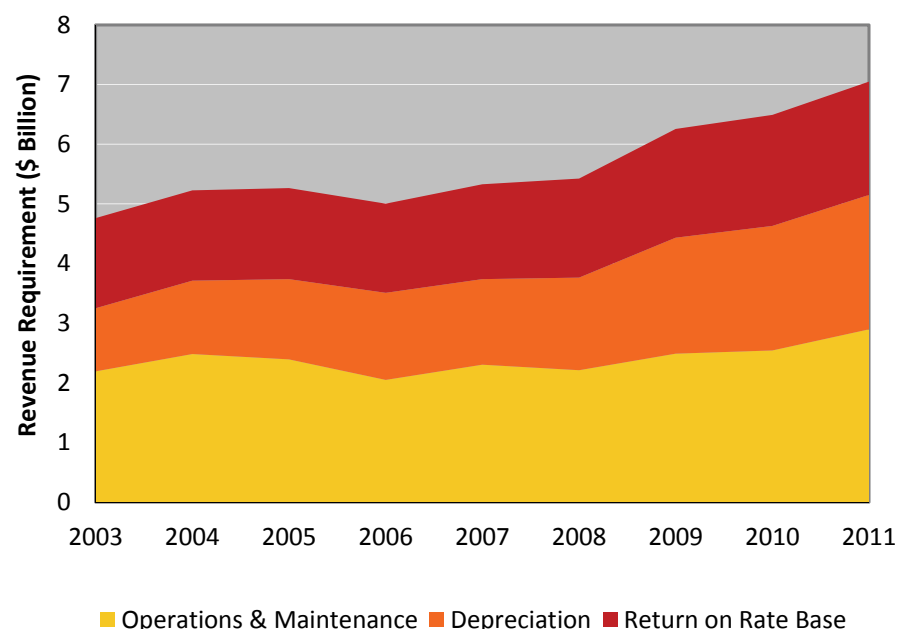
Source: Figure is from the 2024 Costs Report. The Costs Reports do not provide the data for these figures. Note, while the figure is in nominal terms, as it is copied from the CPUC report, our references to costs in the text are in real terms (2024\$).

7 For instance, SCE’s Edison SmartConnect program ran from 2009-2012. PG&E ramped up smart meter funding from 2009-2011. PG&E’s Distribution Reliability Improvement Program (DRIP, or Cornerstone Improvement Project) ran from 2009-2014. Figure 7 and all CPUC figures in this paper are in nominal terms, though all costs are reported in real terms (2024\$).

8 The CPUC’s 2022 *Costs Report* notes that the “... significant increase in O&M ... is largely attributable to the timing and approval of higher wildfire mitigation and vegetation management expenses, and authorized significantly higher wildfire liability insurance coverage” (p. 18). Distribution O&M for 2021, 2022, 2023, and 2024 also includes recovery of costs for catastrophic events.

9 PPP costs declined from \$4.0 billion in the 2023 *Costs Report* to \$2.5 billion in the 2024 report. The 2024 *Costs Report* is silent on why distribution revenue requirements increased and PPP revenue requirements decreased by such a large amount between 2023 and 2024.

FIGURE 7. *Nominal IOU Distribution Costs by Cost Component, 2003-2011*

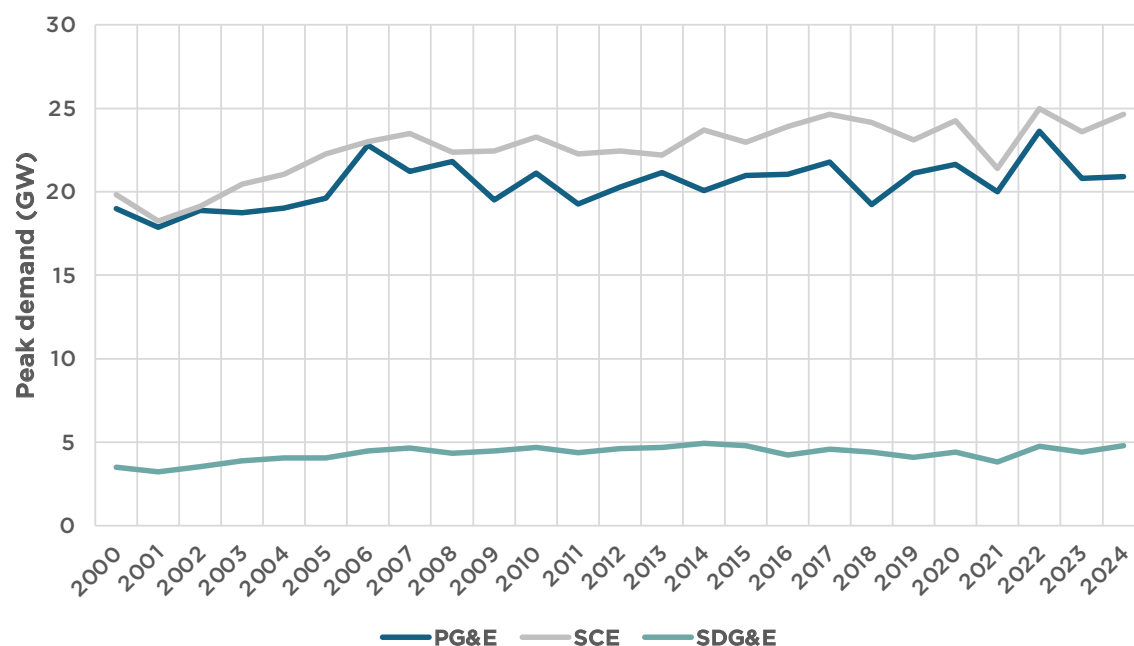


Source: Figure is from the 2011 Costs Report. Note, while the figure is in nominal terms, as it is copied from the CPUC report, our references to costs in the text are in real terms (2024\$).

Distribution investments are driven primarily by local peak demand forecasts. If total (bundled + delivery) sales fell in the 2010s (Figure 4), it raises the question of whether real distribution costs should have also declined rather than remaining approximately constant in real terms for most of the 2010s. Without distribution system loading data it is difficult to answer this question.

However, at the level of the IOU systems, peak demand over the 2010s was relatively stable for PG&E, increased slightly for SCE, and declined slightly for SDG&E (Figure 8). Because the distribution system is sized around local peak demands, if demands are relatively stable it suggests that the distribution system revenue requirement should remain approximately constant in real terms.

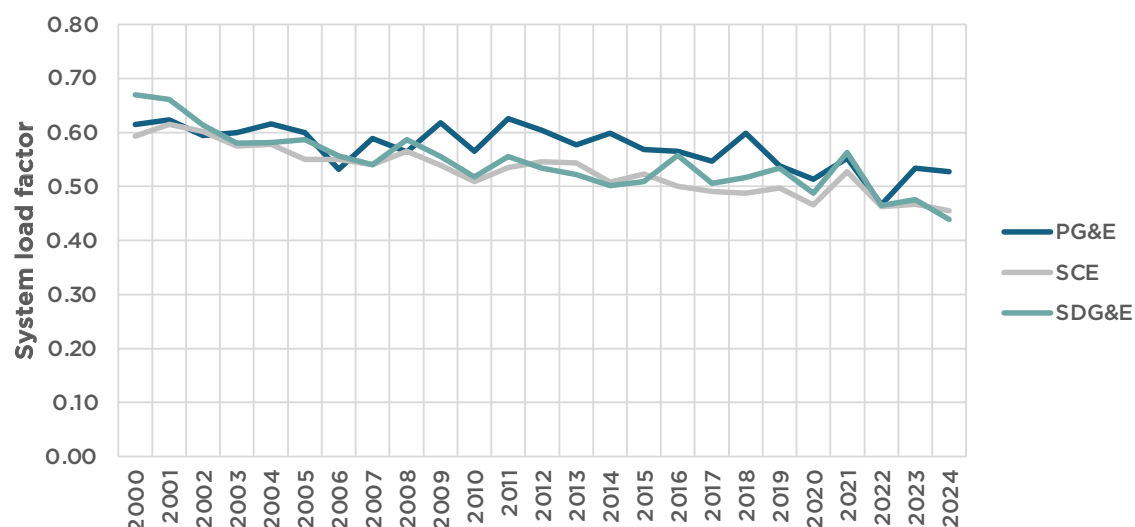
FIGURE 8. *Peak Demand in the PG&E, SCE, and SDG&E Planning Areas, 2000-2024*



Source: Peak demand data is “Historical Net Peak” in Form 1.5 of the CEC’s California Energy Demand Update (CEDU) 2024 Forecast, <https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-2>.

The peak demands in Figure 8 and declining sales (Figure 4) suggest that the IOUs’ system load factors — average demand divided by peak demand — should be declining, which indeed has been the case since the early 2000s (Figure 9). In the 2000s, declines in system load factors were the result of peak demand growing faster than energy demand. Beginning in the 2010s, peak demand flattened but energy demand declined, again resulting in declining load factors. Because electricity systems are sized around peak demand, systems with declining load factors will tend to see increases in their average per kWh costs and volumetric rates, even if utility revenue requirements are constant.

FIGURE 9. System Load Factors in the PG&E, SCE, and SDG&E Planning Areas, 2000-2024



Source and notes: Energy demand data is from “Total Energy to Serve Load” in Form 1.2 of the CEDU Forecast. Total Energy to Serve Load is total consumption plus losses minus self-generation for each utility planning area.

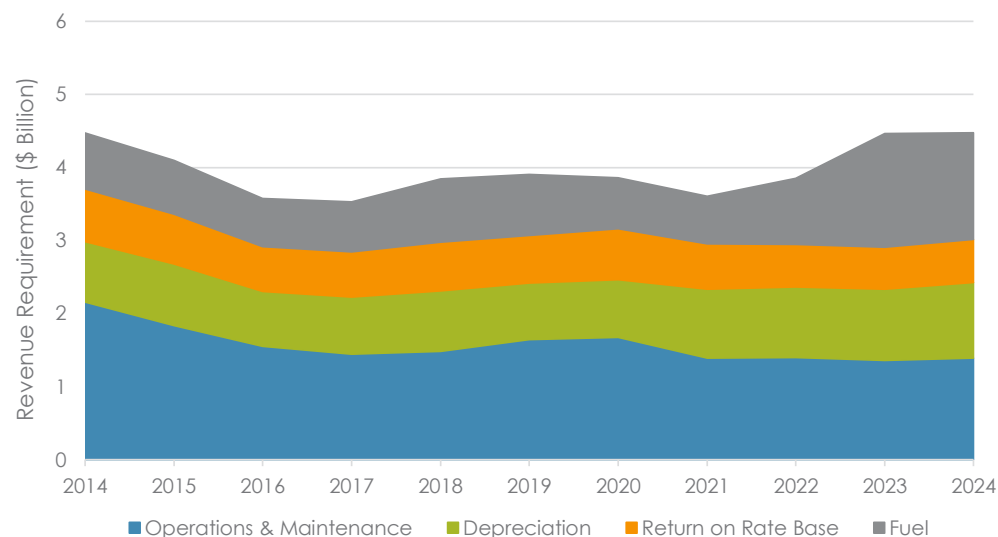
2.3 GENERATION COSTS

As part of market restructuring under AB 1890, the IOUs divested most of their thermal generation in 1998. However, they retained their nuclear and hydro generation and over the next two decades were allowed to retain or invest in some additional gas-fired generation. To provide the additional supply needed to meet demand, the IOUs procured generation capacity and energy through long-term contracts or CAISO energy market purchases. Current IOU generation costs are thus a mix of utility-owned generation (UOG) costs (40% in 2024) and purchased power costs (60%).¹⁰

IOU revenue requirements for UOG (excluding fuel) increased from around \$1.5 billion in 2003 (nominal) to around \$3.5 billion in 2010 and declined to around \$3 billion in 2024. Most (71% in 2024) of the IOUs’ revenue requirement for UOG (excluding fuel) consists of nuclear and hydro costs.

¹⁰ These shares are based on the share of purchased power in the IOUs’ generation revenue requirement. UOG is assumed to be one minus the share of purchased power.

FIGURE 10. *Nominal Utility UOG Costs by Component, 2013-2024*



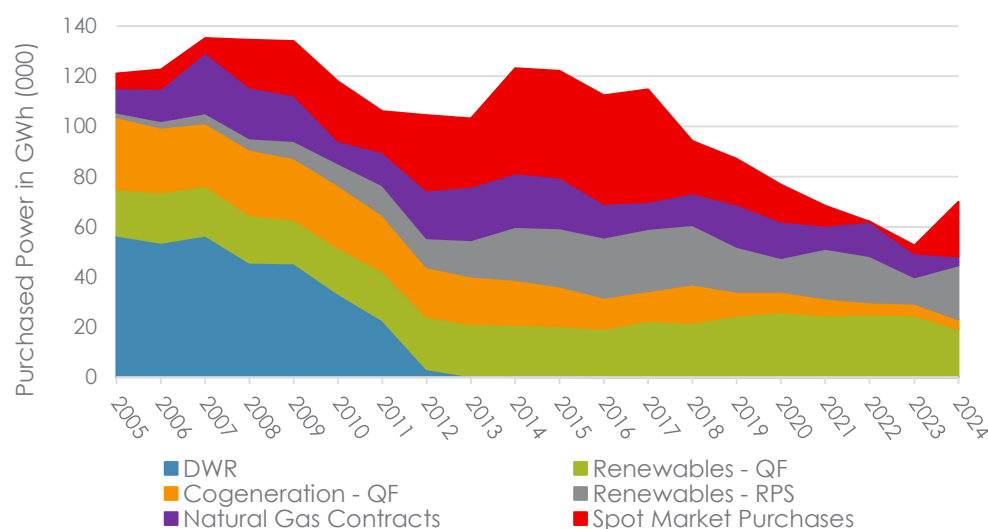
Source: Figure is from the 2024 Costs Report. Note, while the figure is in nominal terms, as it is copied from the CPUC report, our references to costs in the text are in real terms (2024\$).

The IOUs have purchased several types of power over the past 20 years:

- ▶ **DWR contracts** – long-term contracts signed by the DWR on behalf of the IOUs after the electricity crisis in 2001 and paid for by ratepayers
- ▶ **Renewables QF** – QF contracts with small-scale renewable generators
- ▶ **Cogeneration QF** – QF contracts with cogeneration facilities
- ▶ **RPS contracts** – contracts with larger-scale renewable generators to meet the IOUs’ RPS obligations
- ▶ **Natural gas contracts** – longer-term and shorter-term contracts with natural gas generators
- ▶ **Spot market purchases** – procurement of day-ahead and real-time energy, ancillary services, and other reliability and administrative costs in the CAISO market

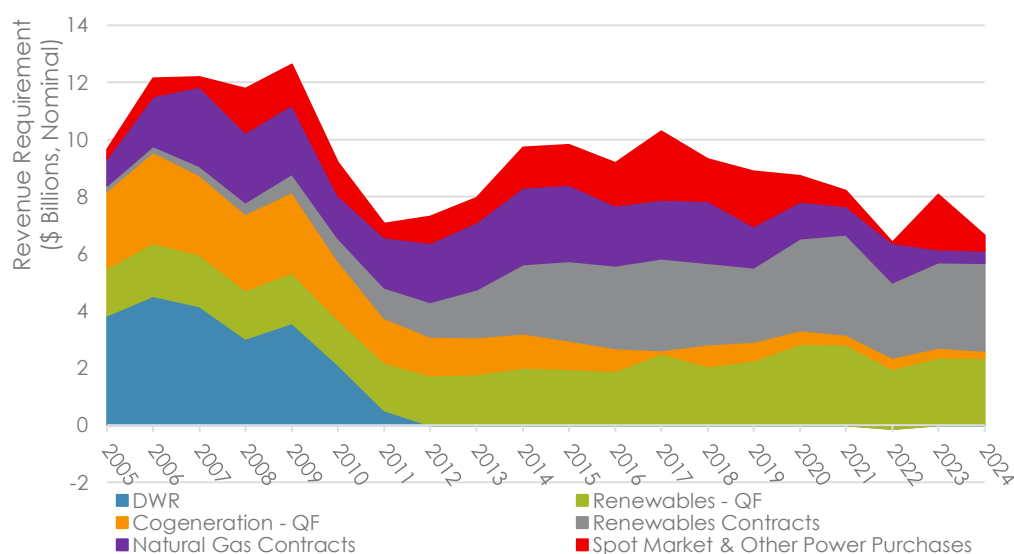
Figures 11 and 12 show the IOUs purchased power and revenue requirements for purchased power from 2005 to 2024, for each of the types of purchased power listed above.

FIGURE 11. IOU Purchased Power Mix, 2005-2024



Source: Figure is from the 2024 Costs Report.

FIGURE 12. Nominal IOU Revenue Requirements for Purchased Power, 2005-2024



Source: Figure is from the 2024 Costs Report. Note, while the figure is in nominal terms, as it is copied from the CPUC report, our references to costs in the text are in real terms (2024\$).

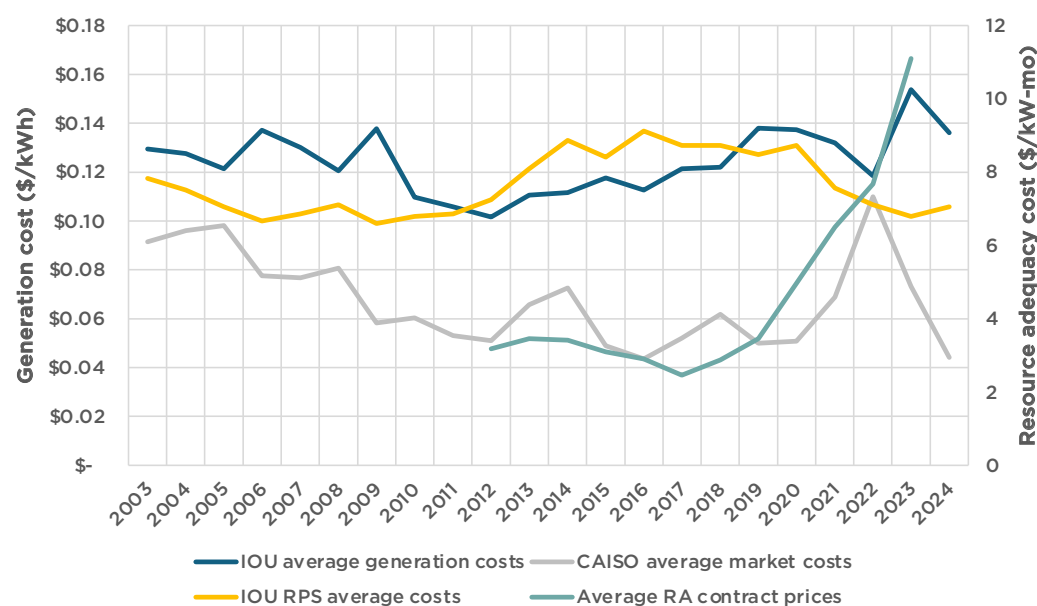
The two figures provide one possible narrative for trends in the IOUs' average generation costs.¹¹ In the 2000s, the IOUs' purchased power consisted mostly of higher cost DWR contracts and

¹¹ These two figures should be interpreted with caution. The implied RPS contract price (revenue requirement divided by purchased power) in 2023 in the figure is around \$200/MWh (nominal \$), though in the 2023 *Costs Report* the CPUC states that, "The weighted average RPS procurement expenditures for the IOUs decreased from 12.4 ¢/kWh in 2021 to 10.5 ¢/kWh in 2022, in real dollars" (p. 36). The implied spot market price in 2023 is several thousand dollars per MWh, which, even accounting for netting of market revenues and costs and adjustment accounts, suggests that something might be wrong with the 2023 data. The purchased power trends figures in previous *Costs Reports* also appear to have data issues; for instance, in the 2014 report the revenue requirement for renewable QFs is zero in 2016, though in later reports it is approximately the same value as in 2015.

renewable QF and cogeneration QF payments. As these DWR and QF contracts rolled over and with falling average wholesale (CAISO) market costs (Figure 13), IOU average energy (UOG + purchased) costs declined from 2009 to 2012. In the early 2010s, the IOUs began to sign long-term renewable contracts to meet their RPS requirements, which drove up IOU generation revenue requirements between 2012 and 2014.¹² This period coincided with a sharp increase in CAISO market costs (+ \$10-\$15/MWh, Figure 13), due to higher natural gas prices, which does not appear to have affected IOU spot market purchases (see Figure 12) but may have had indirect impacts on IOU generation costs.¹³

After 2014, IOU RPS costs stabilized (Figure 13) but load migration to CCAs accelerated, leading to a decline in sales (Figure 4). Although the IOUs' purchased power declined by about the same amount as the decline in sales between 2014 and 2024, their total generation revenue requirement declined only moderately because most of their purchased power costs were locked up in longer-term RPS, renewable QF; and to a lesser extent, RA contracts.¹⁴ As a result, average IOU generation costs increased between 2010 and 2020 despite a generally falling trend of CAISO market costs and RA contract prices (Figure 13). The sharp increase in CAISO market costs and average RA prices over 2019-2023, due to higher natural gas prices and tightening RA supply, did not appear to have affected IOU generation costs until 2023 but may have affected the CCAs and other suppliers much earlier, increasing average electricity rates for the state as a whole between 2020 and 2023.

FIGURE 13. Real IOU Average Generation Costs, IOU Average RPS Procurement Costs, CAISO Average Market Costs, and RA Contract Prices (2024\$), 2003-2024



12 The CPUC's *Padilla Report* (2015) series attributes this increase in costs to the fact that the IOUs began signing contracts with new, rather than existing, renewable facilities to meet their RPS obligations during this timeframe: "the IOUs contracted with existing renewable facilities at the beginning of the RPS program and with mostly new facilities in more recent years in order to meet the 20% and 33% RPS targets" (p. 5). Based on Figure 1 (p. 11) in the 2024 *Padilla Report*, it appears that average IOU RPS procurement expenditures leveled off after 2014.

13 Higher market price projections during this time period could have led to higher priced contracts, for instance. See the CAISO's 2014 *Annual Report on Market Issues & Performance* for more on the drivers behind market price increases.

14 According to EIA data, bundled sales fell by 52%, from 167 TWh in 2014 to 82 TWh in 2024. From Figure 11, the IOUs' purchased energy fell by approximately 55%, from around 125 TWh in 2014 to around 55 TWh in 2023 (the increase to 70 TWh in 2024 was entirely met through spot market purchases). IOU contracts are subject to a variety of regulatory rules that govern contract lengths. SB 350 requires that 65% of RPS energy procurement must be from long-term contracts of 10 years or more. The CPUC's standard offer contracts adopted in 2020 (Rulemaking 18-07-017) create 7-year maximum terms for existing resources and 12-year maximum terms for new resources. Most IOU contracts with new resource adequacy resources, procured through long term procurement plans or more recently integrated resource plans, have been for 10 years.

Sources and notes: CAISO total market costs are “average total costs of energy and reserve” from the CAISO’s Annual Report on Market Issues & Performance. These costs include day-ahead energy costs, real-time energy costs, the CAISO’s grid management charge, bid cost recovery costs, reliability costs, and reserve costs. The IOUs appear to include all of these costs in “spot market & other power purchases” (Figure 12). IOU average RPS costs are recreated from Figure 1 in the 2025 Padilla Report: Costs and Cost Savings for the RPS Program. These costs are weighted average RPS procurement expenditures. They are in 2024 dollars but were deflated using a different index than the other series in this figure. RA contract prices are weighted average contract prices for system RA from the CPUC’s annual Resource Adequacy Report series. This series did not report weighted average prices before 2012. Data for 2024 was not available at the time of writing.

2.4 TRANSMISSION COSTS

The IOUs’ transmission revenue requirements may include several categories of costs:

- ▶ Costs for transmission projects selected through the CAISO’s annual transmission plan
- ▶ Costs for lower voltage, “self-approved” transmission projects that are repair and replacement related and are not reviewed or approved in the CAISO transmission planning because they do not expand transmission transfer capacity
- ▶ Transmission network upgrade costs triggered through generator interconnection
- ▶ Reliability costs that are not included in other cost categories¹⁵

FERC regulates most transmission costs and rates. The CPUC represents the interests of California ratepayers as an intervenor in FERC rate cases. The CPUC established a Transmission Project Review (TPR) Process in 2023 to review the IOUs’ transmission investments.¹⁶

The CAISO’s transmission planning process (TPP) is also regulated by FERC rather than the CPUC. Despite this, inputs to the TPP draw heavily from state processes. Load forecasts used in the CAISO’s transmission plan are based on forecasts from the California Energy Commission’s (CEC’s) Integrated Energy Policy Report (IEPR) process, adapted by transmission owners to create node-specific demands. Unlike most other ISOs, the TPP uses a long-term generation forecast in all of its transmission studies. This forecast is based on resource portfolios developed by the CPUC.¹⁷

Aside from the \$1.0 billion decline in annual transmission revenue requirements between 2023 and 2024, real transmission costs have been on an upward trend since 2007 (Figure 14). The 2023-2024 decline was reportedly due to true-ups and lower O&M spending on wildfire mitigation. For 2007-2023, there are multiple possible factors that may have driven increases in IOU per customer average transmission costs.

- ▶ Load growth, shifts in the location of demand, or load forecast error
- ▶ Generator deliverability costs
- ▶ Aging infrastructure
- ▶ Strategic behavior
- ▶ Wildfire-related costs

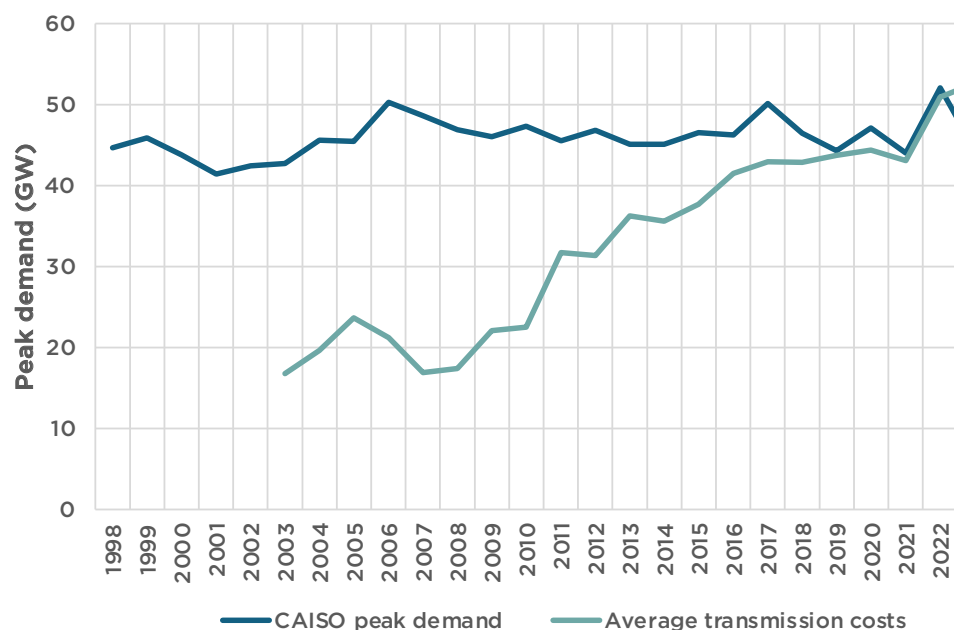
15 For instance, it appears that in the early 2000s the IOUs included some CAISO market costs in their transmission costs. See for instance, the 2011 *Costs Report*. Over time, these costs appear to have been moved to purchased power costs.

16 The TPR consolidated separate review processes for PG&E and SCE, included SDG&E, standardized reporting, and increased opportunities for stakeholder engagement.

17 This approach — using state agency-generated load forecasts and resource portfolios to assess reliability needs, ostensibly including generator RA deliverability needs, in shorter-term transmission planning and allocating costs through transmission charges to loads — is unique to California. At the very least, the cost allocation that results from this approach would likely need to change if the CAISO were to expand to an RTO.

At the system level, load growth should not have been a significant driver of transmission costs in California, as CAISO's total coincident peak demand has been relatively flat since 2006 (Figure 14).¹⁸ It does not appear that either the CEC or the CAISO publish either data on historical forecasts or forecast errors, making it difficult to assess load forecast accuracy.¹⁹

FIGURE 14. CAISO Coincident Peak Demand and Average IOU Transmission Costs (2024\$)



Sources and notes: CAISO peak demand is from <https://www.caiso.com/documents/californiaisopeakloadhistory.pdf>. Average transmission costs are from Figure 2. Before at least 2010, the IOUs transmission revenue requirements included some CAISO costs related to congestion and other operational reliability issues. In a footnote, the CPUC's 2011 Costs Report explains that the spike in transmission costs in 2005 was primarily due to "reliability services" and "intra-zonal congestion costs," for which it cites the CAISO's 2005 Annual Report.²⁰

Most CAISO-approved transmission investments over the past two decades appear to have been driven by reliability needs rather than economic or public policy needs.²¹ However, the CAISO's incorporation of CPUC generation forecasts in its reliability planning makes it difficult to discern the extent to which reliability needs have been driven mainly by changing load patterns, generator retirements, generator additions, or end-of-life replacement.²² The limited amount of either economic or public policy transmission needs identified in CAISO's transmission plans suggests that reliability transmission may have met a significant amount of generation-driven needs for congestion mitigation and resource adequacy. However, again it is difficult to confirm whether reliability has been the primary driver of transmission expansion because generator interconnection costs are reimbursed to generators and included in the IOU transmission revenue requirements.

18 This paper does not explore whether changes in the location of demand could have been a major driver of transmission costs.

19 The CEC did not respond to inquiries about whether such data might be available.

20 As an aside, it is not clear how accurate this statement is. In the *Costs Report*, the spike in costs appears to be attributable to PG&E, but the 2005 CAISO report indicates that most of its reliability-related operating cost increases in 2004 – due to increases in minimum load cost compensation (MLCC) and out-of-sequence (OOS) costs – were due to congestion in the Los Angeles area.

21 This statement is based on a high-level review of CAISO transmission plans. This paper did not attempt to do a more systematic analysis of the categorization and costs of transmission projects.

22 CAISO also does not provide a summary of transmission costs by category, as some other ISOs do.

Self-approved transmission investments have been a large portion (50%) of the IOUs' transmission capital expenditures since at least 2013.²³ In 2018, the CPUC initiated efforts to increase transparency around self-approved investments, alarmed by the lack of oversight and the amount of spending on these projects.²⁴

The impact of replacement-related investments on the real transmission revenue requirement should, in principle, be negligible, as an old asset (the replaced facility) is fully depreciated and removed from the utilities' books and replaced by a new one. However, that may not occur in practice if the new asset is more expensive in real terms or if old assets are not yet fully depreciated. It is difficult to tell how much self-approved projects have driven increases in IOU transmission revenue requirements. The CPUC ultimately does not have jurisdiction over these costs.

Based on the Costs Report series, wildfire costs also appear to be an important driver of higher transmission costs since 2020, but this paper did not do a deeper exploration of FERC rate cases to assess the relative contribution of wildfire-related costs versus other different drivers.²⁵

3 CONCLUSIONS

There are two separable questions surrounding rate increases in California over the last two decades:

1. Why are California's electricity rates significantly higher than those in other states?
2. Why have California's investor-owned utility costs increased much faster than inflation over the past two decades?

Part of the answer to the first question would involve benchmarking unit costs — for instance for upgrading a distribution substation — and comparing them against other states. This paper does not explore differences in unit costs, but it would be useful to do so. The trends leading to high unit costs in California began decades ago.

The paper does offer some insight on the first question through its analysis of the second. Distribution, transmission, and generation all contributed to rising utility costs over 2003-2024. Real per customer distribution revenue requirements were, in fact, flat for most of this period except for three large increases: (1) a brief increase in capital spending from 2008-2011, which was likely due to AMI and, to a lesser extent, other smart grid investments, (2) increases in O&M spending in 2020-2022 due to wildfires, and (3) increases in O&M spending and returns in 2023-2024. Increases in costs in these three periods are equivalent to 29%, 32% and 37%, respectively, of the \$8.7 billion per year increase in IOU real distribution revenue requirements between 2003 and 2024.

23 The 2023 *Costs Report* reports that self-approved projects accounted for 50% of the IOUs' transmission investments between 2013 and 2022, though these data are based self-reported totals before the IOUs began to report project-level data to the CPUC in 2020.

24 The CPUC was concerned with self-approved projects at all three IOUs but PG&E's scale of self-approved projects was several fold larger than either SCE or SDG&E's in terms of both absolute investments and percent of total capital additions. The CPUC discovered that PG&E only had a limited planning process in place for these projects. See presentations by Traci Bone and Geneva Looker (<https://www.ferc.gov/sites/default/files/2020-08/BoneCPUC.pdf>) and Traci Bone (https://www.energy.gov/sites/prod/files/2018/11/f57/3-2%20Bone_The%20Disconnect%20Between%20Transmission%20Policies%20and%20Planning%20-%20DOE.pdf).

25 The *Costs Report* series only reports transmission costs at the aggregate transmission revenue requirement level.

Real per customer transmission costs rose steadily between 2007 and 2024. The drivers of transmission cost increases likely include a lack of FERC oversight and investments to support deliverability for renewable generation, but the contribution of different drivers is unclear. Transmission is now a much larger share of total electricity costs in California than it was in the 2000s. The increase in IOU real transmission revenue requirements between 2003 and 2024 (\$2.7 billion per year) was around one-third of what it was for distribution.

Load migration to CCAs has complicated understanding of generation cost changes. For IOUs, generation costs for bundled customers decreased in the 2000s, as the effects of the CA crisis wore off, then increased after 2010 due to a combination of higher RPS costs (2011-2014) and load migration (after 2014) that left the IOUs with expensive longer-term contracts. CCA generation costs are not regulated by the CPUC though likely track IOU costs. Increases in CAISO market costs, due to higher natural gas prices, and RA costs, due to tightening supply, after the pandemic may have contributed to generation cost increases.

3.1 PRIORITY AREAS AND CONSIDERATIONS FOR ADDRESSING HIGH RATES

The results of this analysis raise several considerations for how electricity costs and rates in California might be stabilized and reduced over the longer term. These considerations focus on identifying issue areas rather than solutions.

Benchmarks, metrics, goals, and expectations. Part of the challenge in developing solutions that address rising electricity rates is that there is still so much uncertainty about what the drivers are. Arriving at more rigorous, authoritative explanations of why changes in costs and rates are occurring and whether changes are reasonable requires more visibility, or, said differently, more transparency in the right places. It may involve benchmarking IOU costs, defining affordability and setting metrics to track it, and developing cost metrics that are more aligned with the realities of California's increasingly unbundled retail sector and can be used to track costs for the next 10 to 20 years. A goal of more transparency would be to align expectations throughout the industry of what costs and rates should be — for instance, what level of distribution (\$/customer-mo or \$/kW-year) and transmission network costs (CAISO transmission access charge) is reasonable — to help spur explanations from the CPUC, utilities, the CAISO, the CCAs, and other load serving entities when costs do not align with expectations. Building this kind of foundation for transparency going forward is arguably more important than trying to tweak the CPUC's performance incentives for the IOUs — transparency can be a powerful incentive. There may be a case for developing benchmarks, metrics, goals, and expectations outside of CPUC proceedings and without the CPUC's direct involvement.

Multiple causes and solutions. Sections 1 and 2 of this paper illustrate the multiple drivers and cumulative nature of cost and rate increases in California over time. Tackling high rates will likewise require multiple solutions and prioritization of solutions. Some solutions, like productivity improvements, could be nearer term in both implementation and effects. Others, like reforming electricity retail, are more structural and are likely longer term in both implementation and effects.

The virtues of simplification. California's electricity sector is far too complex, with numerous, overlapping legislative mandates and reporting requirements, a multitude of vintaged utility programs, arcane accounting rules and frequent changes in accounting practices, copious planning and stakeholder processes, extensive yet detailed rules for procurement, and overlapping RA processes. Excessive complexity makes it difficult to track changes over time and determine cost reasonableness. It inhibits competition, because new entrants need guides to navigate complexity,

and weakens regulatory oversight and oversight of regulators, because complexity makes it difficult for regulators and stakeholders to focus. Radical simplification would likely aid efforts to reduce electricity costs and rates, but it would require cleaning current house and rethinking the state's approach to policymaking in and regulation of the electricity industry going forward.

Capital versus O&M costs and rate flexibility. Regulatory accounting means that utility capital investments will typically be in rates for decades, limiting the ability of regulators to have nearer-term influence over rates. O&M costs are operating expenses and are more flexible. Given the relatively high share of O&M costs in the IOUs' revenue requirement, there may be opportunities for nearer-term productivity improvements through more efficient operating expenses. Cost benchmarking could help to provide more visibility on areas for productivity improvements. Productivity improvements would likely benefit both ratepayers and shareholders.

A new paradigm for regulating wildfire costs. Wildfire-related costs are now an unsustainably large portion of the IOUs' total revenue requirements (reportedly 10%-27% in 2024).²⁶ The scale of wildfire-related costs — \$8.4 billion per year in 2024 — is currently unique to California and requires more holistic, creative, and likely legislative solutions. It will not be possible to address high electricity rates in California without a different approach to utility investments in wildfire prevention and how the CPUC regulates utilities' wildfire-related costs.

Making more efficient generator use of the transmission system. Deliverability of renewable generation has likely been a significant driver of transmission cost increases, and the CAISO's most recent (2024-2025) transmission plan suggests that it will continue to drive transmission expansion.²⁷ Yet if California is to meet its greenhouse gas emission goals at a reasonable cost, a different approach to transmission planning and expansion may be needed. In evaluating whether and how to rethink the current approach, the key question is whether it leads to reasonable tradeoffs — in outcomes rather than in theory — between incremental transmission and resource costs, and between cost and policy certainty.²⁸

Making more efficient demand-side use of the distribution and transmission systems (or, finding ways to incentivize more efficient peak demands). System load factors have been declining for all of the IOUs since the early 2000s, as a result of demand-side programs, rooftop solar adoption, and possibly changes in customer behavior and demographics. Because distribution and transmission systems are built to meet peak demand, declining load factors increase rates. Mathematically, improving load factors means that peak demand must decline faster than energy demand. The notion of "efficient use" will likely change significantly in an era with lower-cost battery storage, electric vehicle charging, electric heating, and large data center loads. Incentivizing more efficient peak use of the distribution and transmission systems likely requires rethinking existing programs and developing new solutions.

Longer-term, sustainable vision for the retail sector. California's retail sector is caught between the post-electricity crisis paradigm, in which the legislature and CPUC relied on the IOUs to

²⁶ Wildfire cost estimates in this paragraph are from the 2024 *Costs Report*.

²⁷ The CAISO's 2024-2025 *Transmission Plan* states that, "The need for additional generation of electricity over the next 10 years has escalated rapidly in California as it continues transitioning to the carbon-free electrical grid required by the state's clean-energy policies. This in turn has been driving a dramatically accelerated pace for new transmission development in the last two, current, and future planning cycles" (p. 5).

²⁸ The current approach is that the CEC and CPUC develop load, generation, and storage inputs for the CAISO's transmission plan through the IEPR and statewide integration resource planning (IRP) processes. The IRP does now include transmission constraints and expansion, which means that the portfolios are being optimized for transmission availability and cost. The higher-level questions are (a) the extent to which there may have been more cost-effective alternatives to transmission that was selected and built, which is an empirical question that can be examined through utilization metrics and other analysis; and (b) the extent to which the CPUC/CASIO or market participants are better positioned to make tradeoffs between deliverability and energy-only status, and between new transmission and other approaches to congestion mitigation.

implement state policy and ensure RA program compliance, and the current reality, which is that the IOUs are now effectively default service providers. In principle, default service providers should not have a large share of long-term contracts or utility-owned generation in their resource portfolios. A long-term, sustainable vision for the retail sector would need to address the role of the IOUs as load service entities, the future of RA markets and the RPS program, the role of procurement planning versus emissions regulation, and approaches to contract duration requirements and regulation.

NEM export rates and their effects on costs and rates. Rooftop solar increases average electricity rates due to its effect on retail sales, but the main direct effects of NEM are distributional rather than on average rates.²⁹ The CPUC estimates that the cost shift associated with NEM was around \$7 billion in 2024, which for comparative purposes is on par with the total increase in the IOUs' real distribution revenue requirement between 2003 and 2024 (\$8.7 billion, 2024\$). Addressing export rates in NEM could thus provide significant rate reductions for some customers but would only help to reduce average electricity costs to the extent that it slows adoption and self-consumption of rooftop solar.

Transmission cost regulation for self-approved projects. Issues with self-approved transmission costs are not unique to California.³⁰ Solutions may require different approaches to oversight and regulation, such as more concurrent approaches to transmission cost regulation that allow states to review and approve replacement costs.

²⁹ One could argue that the scale of rooftop solar would be smaller without NEM, which would be an indirect way in which NEM increases rates through reduced sales.

³⁰ See, for instance, Claire Wayner et al., 2024, *Mind the Regulatory Gap*, <https://rmi.org/insight/mind-the-regulatory-gap/>.