



MAKING CALIFORNIA'S ELECTRICITY CHEAPER

AN AFFORDABILITY AGENDA FOR THE GOLDEN STATE

SEPTEMBER 2026

GridLAB

ENERGY
INNOVATION 

This report was developed by Energy Innovation and GridLab, building on ideas generated in a workshop hosted in January 2026 jointly by Energy Innovation, GridLab and RMI, intended to identify solutions to solve California's high electricity rates crisis.

Contributing authors

Mike O'Boyle
Energy Innovation

Priya Sreedharan
GridLab

Cara Goldenberg
RMI

Fritz Kahl
3rdRail, Inc.

Katie Pickrell
Evolved Energy Research

Brendan Pierpont
Energy Innovation

Ric O'Connell
GridLab

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Reviewers

Ari Gold-Parker
Energy and Environmental Economics, Inc.

Cassady Craighill
GridLab

Cliff Rechtschaffen
Former California Public Utilities Commission Commissioner

Dan Adler
Net Zero California

Ed Smeloff
Independent Consultant

Jake Glassman
RMI

Matt Freedman
The Utility Reform Network

Michael Mastrandrea
Stanford University

Shannon Stirone
Energy Innovation

Silvio Marcacci
Energy Innovation

Travis Ritchie
UC Berkeley Center for Law, Energy, and Environment

Workshop organizers

Priya Sreedharan and Ric O'Connell
GridLab

Brendan Pierpont and Michael O'Boyle
Energy Innovation

Cara Goldenberg, Jake Glassman and Rachel Gold
RMI

Workshop participants

Ari Gold-Parker
Energy and Environmental Economics, Inc.

Brian Turner
Advanced Energy United

Cliff Rechtschaffen
Former California Public Utilities Commission Commissioner

Curtis Seymour
AC Strategies

Dan Adler
Net Zero California

Duncan Callaway
University of California, Berkeley

Ed Smeloff
Independent Consultant

Ethan Elkind
UC Berkeley Center for Law, Energy, and the Environment

Fritz Kahl
3rdRail, Inc.

Jose Torres
Affordable Energy Campaign

Katie Pickrell
Evolved Energy Research

Matt Freedman
The Utility Reform Network

Merrian Borgeson
Natural Resources Defense Council

Michael Colvin
Environmental Defense Fund

Michael Mastrandrea
Stanford University

Neha Bazaj
Gridworks

Ryan Pletka
Pacific Gas & Electric Company

Ryan Tracey
Sonoma Clean Power

Shana Lazerow
Communities for a Better Environment

Travis Ritchie
UC Berkeley Center for Law, Energy, and the Environment



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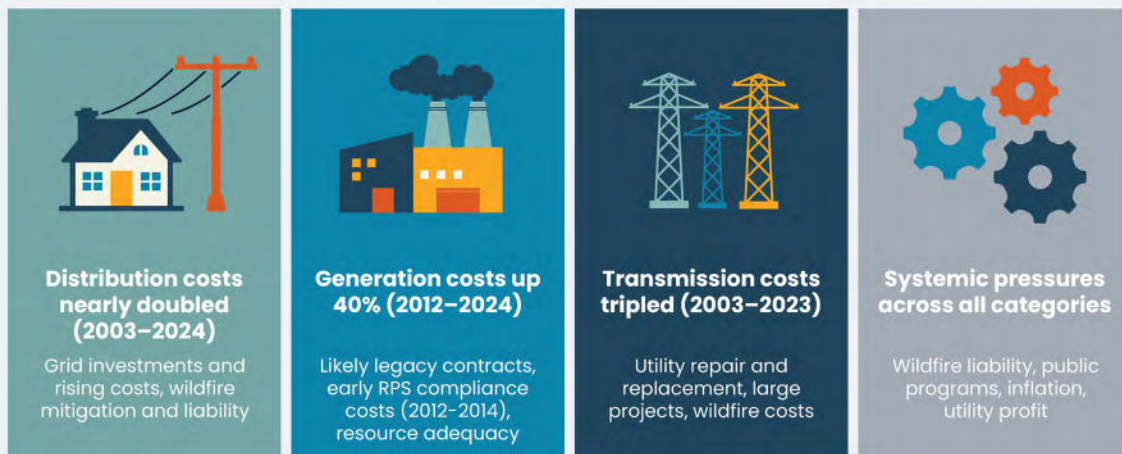
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Executive Summary

Affordability is at the heart of almost every policy conversation across the nation, and California is facing a particularly acute energy affordability crisis — the state’s electricity rates are now the second highest in the nation and double the country’s average. Between 2000 and 2024, California’s electricity rates rose faster than inflation and became the highest in the contiguous United States, more than 50% higher than the US average. These prices are untenable, straining household budgets, and threatening the state’s electrification path to a climate-neutral economy.

California's real residential electricity rates rose over 50% from 2000–2024. Here's why:



More than 80% of Californians rank lowering bills as a top or important priority for state leaders, and the state’s elected officials have a duty to address these intertwined problems for their constituents.¹ Failure to address California’s rising rates also risks the state’s progress toward lowering its greenhouse gas emissions, which itself is a root-cause affordability tool as wildfires grow more severe with a changing climate and the associated risks and mitigation grow more expensive.

¹ Deploy Action, May 2026, Deploy Action poll shows California voters want grid efficiency, utility accountability, and lower power bills press release. See <https://www.deploy-action.org/newsroom/california-voters-want-grid-efficiency-utility-accountability-and-lower-power-bills>



In response, GridLab and Energy Innovation convened a workshop of more than 20 California electricity experts to diagnose what's causing rising costs and develop actionable policy solutions that address the scale of the challenge. This report is informed but not limited by that workshop. It defines a policy roadmap to stabilize and ultimately reduce electricity rates for California's incoming governor, the California Public Utilities Commission (CPUC), the legislature, utilities, and other stakeholders, that will allow California to sustain its clean energy leadership.

There is no silver bullet to drive down rates, but any path forward must address the underlying structures which stakeholders agree led to California's sky-high rates. These factors are complex and include a mix of increased distribution, generation and transmission costs, misaligned utility incentives, complex and overlapping regulatory and legislative mandates, opaque cost tracking and oversight mechanisms, and declining system utilization (which drives up volumetric based rates). All of these problems sit alongside the difficult reality of wildfire risk that utilities are attempting to solve by spending huge sums of ratepayer money. Unfortunately, the utilities' financial health and Californians' safety depend on effective mitigation, but utilities cannot do it efficiently or effectively without coordinated action across local and state governments.

While California's problems are complex, there are clear, actionable solutions to stabilize and reduce California's electricity rates. A fuller list of these policy recommendations is available below, and explained in more detail in the full report.

First, California should focus on **lowering overall utility costs**. This can be done through institutional reforms, regulatory simplification, improvements to cost transparency, better oversight of and alignment of utility incentives with affordability, and strategic wildfire spending. The state needs a concerted effort to **simplify regulatory proceedings** while pausing new programs and proceedings (to be observed by both the legislature and the CPUC). Regulatory simplification should include permitting reform by state agencies that reduces barriers to energy projects. The CPUC should also refine its methods to **improve transparency on utility costs**, improving both public reporting and transparency and utility accountability to the CPUC. Similar to standard financial accounting inside utilities or with publicly traded companies, the CPUC could create standard templates for aggregate cost reporting and tracking that facilitate more effective cost oversight, while eliminating redundant mechanisms. To help **align utility incentives with affordability**, CPUC, authorized by the legislature, could more explicitly put investor-owned utilities on a budget, requiring them to keep rates stable by tying profitability to stabilizing rates and meeting affordability targets established by CPUC. Finally, the state needs a **framework to identify how best to invest in wildfire mitigation** across agencies and electric utilities, recognizing the problem goes beyond ignition reduction and should consider community-scale resilience to wildfire.

California's second opportunity is to **redistribute the cost of the electricity grid more fairly**. While electric vehicles and heat pumps use energy more efficiently than fossil alternatives, rate increases cut into customer savings. Policies that **redistribute the fixed costs of the system to a larger pool of customers** through rates can make the cost of electrification much lower for all. The cost of wildfire mitigation is also falling disproportionately on electricity rates. There is an opportunity to build on existing proposals and further **rebalance wildfire mitigation costs toward beneficiaries**, including utility shareholders, communities most vulnerable, and California taxpayers. Finally, rates have done a poor job in rewarding customers who use electricity when the grid has spare capacity. Electrification of small and large customers is an opportunity to realign these incentives, both by improving the rates as well as pairing state incentives with enrollment in utility programs, **rewarding customers for shifting energy use away from peak periods**.

In aggregate, these solutions are an agenda for the next wave of leaders in California to actually solve the state's electricity affordability crisis instead of ignoring the root problems. This paper's recommendations are for the most part not short-term fixes, but rather long-term policy actions to solve the system-wide forces that would otherwise continue increasing rates. A systematic approach that strengthens regulatory cost mitigation tools, more fairly allocates wildfire costs and risk, and improves the distribution of costs can first slow down spiraling rate increases then reduce them over time.

While the tools for immediate rate relief are limited and have their own implementation challenges, California's leaders, including the incoming governor, the CPUC, and the legislature, have a real opportunity to upgrade the structures that produced this crisis. Doing so will

require sustained collaboration across government, utilities, and civil society — but our central message is that continued rate increases are not inevitable.

POLICY RECOMMENDATIONS SUMMARY

CATEGORY 1

Policy opportunities on oversight and reducing total utility costs

Reducing Regulatory Overhead

- **OPPORTUNITY | Reflect on and remedy regulatory complexity at the CPUC.** Create a plan for simplifying proceedings and pair it with a moratorium on new dockets; identify redundant rules, and consider narrowing the CPUC’s remit to core energy issues while relocating special programs elsewhere.
- **OPPORTUNITY | Improve permitting regimes to lower infrastructure costs and remove barriers to third party service providers.** Notably, extend CEQA exemptions and streamlined review (building on GO 131-E) to advanced reconductoring, distribution upgrades, and fully operationalize the Transmission Infrastructure Accelerator; reduce soft costs for customer solar and storage such as instant online permitting and remote inspection for residential systems.

Confront Distrust with Improved Transparency

- **OPPORTUNITY | Create standard templates for aggregate cost reporting and tracking that facilitate more effective cost oversight.** Create a detailed standardized annual cost-tracking framework, that goes beyond reporting required under SB 695 and AB 3264, to enable deeper insight into investor-owned utility (IOU) spending. Demand greater FERC/CAISO oversight and reporting on self-approved transmission projects.
- **OPPORTUNITY | Create a transparent framework for measuring the cost-effectiveness of wildfire risk mitigation spending across agencies and electric utilities.** Building on SB 254, develop a common, cross-agency cost-effectiveness framework to help prioritize spending where it can be most beneficial towards reducing wildfire risk; this will enable targeting measures beyond ignition reduction and consider community-scale hardening.

Align Utility Incentives with Affordability

- **OPPORTUNITY | Put investor-owned utilities on a budget.** This includes exploring a revenue cap tied to limited, predetermined adjustments (e.g., inflation), paired with folding riders/balancing accounts back into base rates to preserve cost-containment incentives.
- **OPPORTUNITY | Tie financial performance to affordability targets.** Begin by assessing the current incentive frameworks and require reporting on affordability and supportive metrics like grid utilization. Over time, link a portion of authorized return on equity (ROE) to meeting affordability and cost-savings goals without sacrificing service quality.

- **OPPORTUNITY | Limit excess utility profits.** This could be an earnings sharing mechanism that refunds a share of earnings exceeding the authorized ROE by a set margin, as used in Hawaii, Minnesota, New York, North Carolina, and Massachusetts.

CATEGORY 2

Policy opportunities on allocating system costs fairly

Modernize Electricity Rate Design

- **OPPORTUNITY | Adjust rates to reflect modern priorities for the electricity system including improved utilization, electrification, and equity.** Build on the income-based Base Service Charge; expand summer baseline credits/supplemental credits for hot-climate customers; design rates that lower marginal costs for electrification; and transition legacy rooftop solar customers to fair and modern rates.

Reduce the Role of Rates in Funding Climate Mitigation and Wildfire Prevention

- **OPPORTUNITY | Rebalance wildfire mitigation costs toward beneficiaries, including utility shareholders, communities most threatened, and California taxpayers.** Expand ratepayer-backed securitization (per SB 254) and explore blended funding from property tax revenues, municipal bonds, and insurance-funded mechanisms to share costs beyond ratepayers.

Reduce Financing Costs and Risk Passed to Consumers

- **OPPORTUNITY | Change the utility's debt-to-equity ratio.** Shift capital structure toward more lower-cost debt and less high-cost equity, within prudent credit-rating limits.
- **OPPORTUNITY | Leverage public financing and ratepayer-backed securitization to finance large investments with low-cost capital.** Expand low-cost public financing for transmission projects (e.g., via the California Transmission Infrastructure Accelerator in coordination with the California Infrastructure and Economic Development Bank) and securitization for major grid investments that reduce wildfire risk.

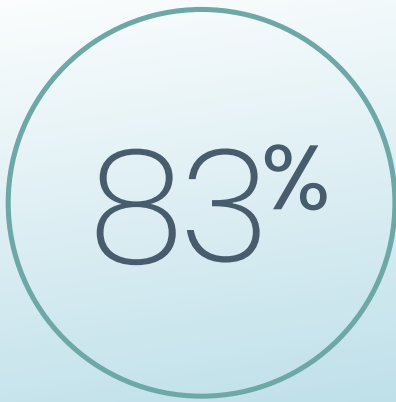
Encourage Customer Flexibility & Improve Grid Efficiency

- **OPPORTUNITY | Combine state electrification incentives with program and rate designs that make electrification affordable and flexible.** Link vehicle and building electrification incentives to enrollment in demand response and flexible charging programs.
- **OPPORTUNITY | Leverage flexible large loads to improve utilization and lead on industrial electrification.** Use flexible grid connections to attract industrial load that can help improve system utilization coupled with careful rate design to ensure that costs are not shifted to other customers.

California's rising rates in context

California electricity rates are double the national average and the second highest in the nation, after Hawaii. While rates have been tracking or exceeding inflation in California for some time, they are now unsustainably high for customers not served by municipal utilities, resulting in a drop in consumers' faith in governmental institutions and electric utilities. According to a recent poll, 83% of Californians say reducing electricity bills should be a top or important priority for lawmakers, while utility profits, utilities' lack of competition, and lax regulatory oversight were cited as the top three reasons people believe are responsible for higher electricity bills. High energy prices are especially hard for lower-income Californians to pay and often forces choices between paying for medical care, energy, housing, and food. In a state known for its high cost of living this is especially unfair and is a problem that cannot be ignored any longer.

In addition to harming consumers today, California's high electricity rates undermine the state's plans to create a climate-neutral economy by 2045. The cheapest technologies involve electrifying factories, buildings, and vehicles at a massive scale. While many electric technologies like EVs and heat pumps carry significant efficiency advantages over direct fossil fuel use, electricity price increases threaten their economics. Rate increases have already clawed back much of the fuel savings for EVs



83%

of Californians say reducing electricity bills should be a top or important priority for lawmakers.

compared to gasoline (before the 2026 Iran war gas price impacts), and threaten to make building and industrial electrification a losing proposition for businesses and consumers. Rather than forcing industries to relocate or electrify elsewhere, California should focus on being an economically attractive place to adopt clean technology. The state's global leadership in clean development is at stake.

To identify innovative solutions to these seemingly intractable problems, GridLab and Energy Innovation convened a two-day workshop in January, 2026, featuring more than 20 California electricity experts, under modified Chatham House Rules. Together, we collaboratively diagnosed the underlying features that led to California's current electricity affordability crisis, collected participant ideas for policy solutions, and developed what participants agreed were the most important and impactful solutions. However, the workshop was not a consensus-building exercise. GridLab and Energy Innovation curated this information to inform our own policy roadmap for California, and the recommendations of this paper should in no way be attributed to workshop participants or the institutions they represent.

This paper is structured in two parts to give policymakers and electricity stakeholders a sense of how we got here and where we are going:

- **Section 1** is a short summary of why California's electricity costs have risen, relying primarily on independent research commissioned by GridLab that helped inform the workshop.²
- **Section 2** aggregates solutions to prevent and reverse the trends of utility cost and rate increases. Together, these constitute important focus areas for California's incoming governor, the PUC, legislature, utilities, community choice aggregators, and other stakeholders to collaboratively turn the page on spiraling utility costs.

Thematically, the workshop and subsequent research revealed an optimism that further rate increases are not inevitable. Institutional inertia, public trust, and politics may be among the hardest factors to overcome. Getting to a future where rates actually decrease will require collaboration across government, utilities, and civil society that help create a shared vision for an affordable electricity system that supports California's clean energy leadership.

² GridLab and 3rdRail, Inc., 2026, An examination of rising electricity costs and rates in California. <https://gridlab.org/portfolio-item/an-examination-of-rising-electricity-costs-and-rates-in-california/> and GridLab and Evolved Energy Research, 2026, California investor owned utility distribution and transmission cost benchmarking. <https://gridlab.org/portfolio-item/california-investor-owned-utility-distribution-and-transmission-cost-benchmarking/>.

SECTION 1.

Why are California's electricity costs rising?

This section draws primarily from the aforementioned reports developed by GridLab in preparation for the workshop — a paper that examines the history of electricity costs and rates in California and a paper that benchmarks distribution and transmission costs on a normalized basis with peer utilities; based on publicly available documents and resources.³ 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. Most of these price increases were concentrated in the investor-owned utilities (IOUs) which serve about two-thirds of California electricity customers.

**California's
real electricity rates
rose by more than 50%
mostly due to IOUs**

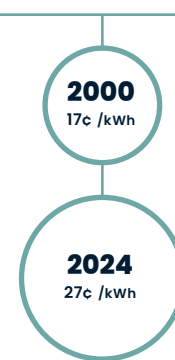
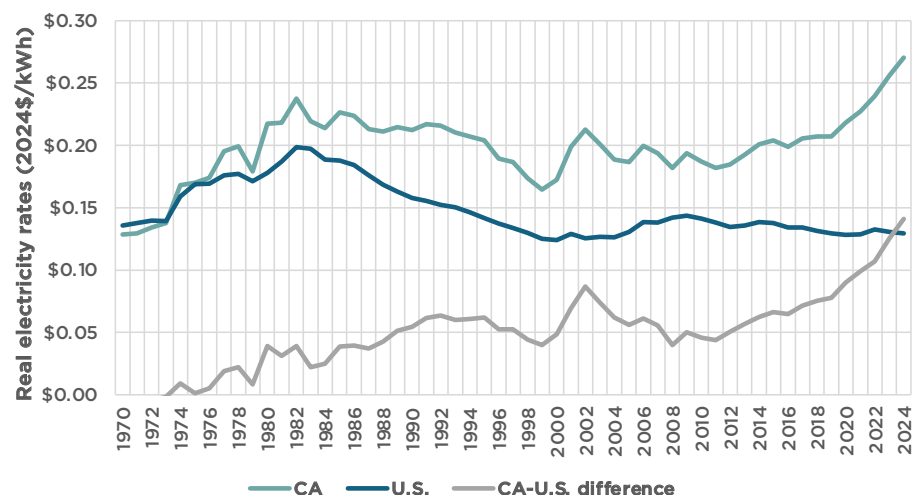


FIGURE 1.

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

(Source: GridLab and
3rdRail, Inc., 2026)



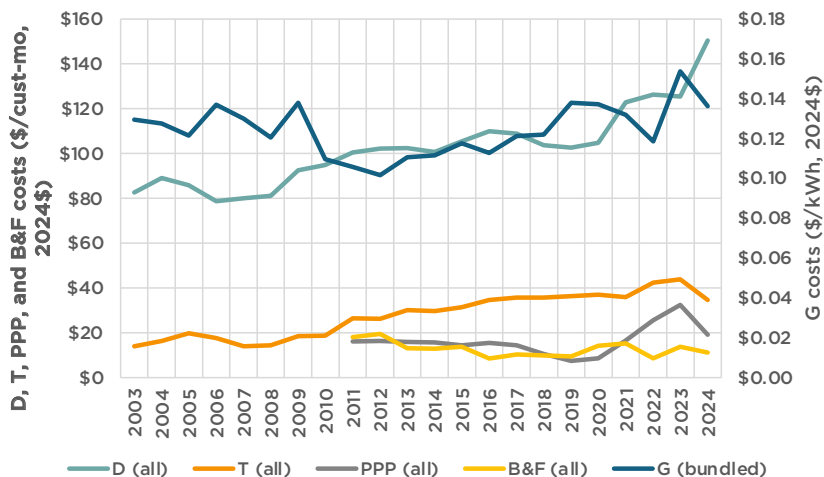
³ For example, cost data that are referenced in "An examination of rising electricity costs and rates in California" are based on the CPUC's California Electric and Gas Utility Costs Report ("Costs Report") series (See cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/reports-on-utility-costs) The cost data referenced in "California investor owned utility distribution and transmission cost benchmarking" are from FERC Form 1 data as compiled and shared by the Catalyst Cooperative Public Utility Data Liberation Project (PUDL) database (See catalyst.coop/pudl/)

Many drivers contribute to rising costs across the three main components of consumer bills: distribution, transmission, and generation. As the graphic below shows, distribution costs were the fastest growing component of utility costs, almost doubling in real terms from 2003 to 2024. In 2024, the highest contributors to overall rates by magnitude are distribution, followed by generation, transmission, and public purpose programs.

FIGURE 2.

IOU Average Costs by Function, 2003-2024

(Source: GridLab and 3rdRail, Inc., 2026)



Distribution costs

The distribution system low-voltage delivery network of poles, wires, and electrical equipment provides power to customers. Service territories for the IOUs are massive and complex — SCE and PG&E each oversee more than a 100,000 mile delivery system across coastal, agricultural, and mountainous regions.

Real annual distribution costs for the three IOUs nearly doubled between 2003 and 2024 (from \$10.7 to \$19.4 billion per year [2024\$]), though for most of this 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:

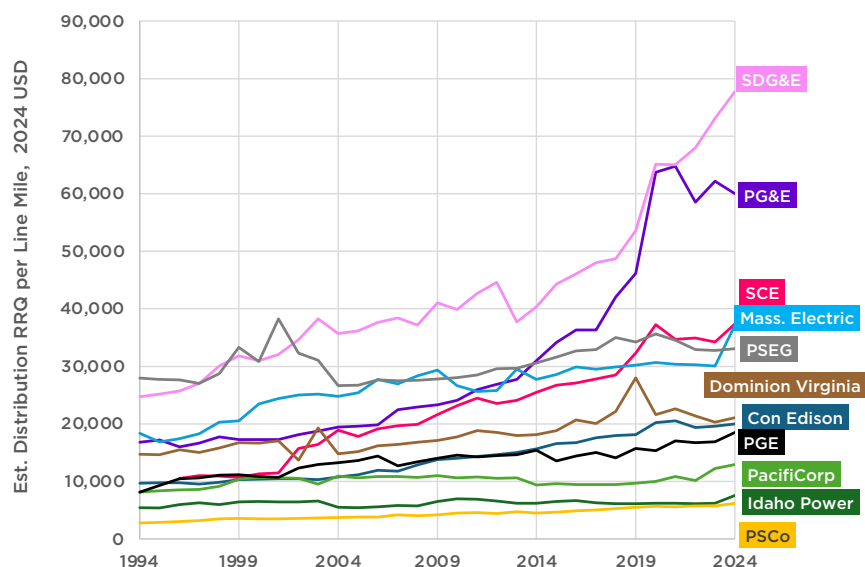
- 2008–2011 saw rates increase due to large capital spending in advanced meters and smart grid infrastructure
- 2020–2022 spending on wildfire prevention and contributions to victim compensation from the Camp fire and other damages
- 2023–2024 saw another increase in wildfire prevention costs as well as higher returns on investment passed through to customers.

California's distribution costs are uniquely high when compared to other utilities, and this has been the case for the past 30 years. All three of California IOUs' distribution costs per line-mile were higher than peer utilities', with SDG&E and PG&E outliers due to uncommonly high capital and O&M spending, respectively. The analysis suggests the impact of recent wildfire mitigation spending in California, including distribution and transmission O&M costs, has been significant. However, other Western utilities with mountainous, fire-prone service territories have not yet observed similar increases, suggesting other structural factors having additional influence over distribution costs.

FIGURE 3.

Electric Distribution
Revenue Requirement
Proxy, Cost per Line-Mile,
2024 USD

(Source: GridLab and
Evolved Energy Research,
2026)



Transmission costs

Transmission costs comprise the high-voltage network of wires and structures that connect large power plants with the substations that feed the distribution system. Transmission is the smallest portion of the bill compared to distribution and generation, but transmission cost growth has still contributed significantly to increases in California's rates. The IOUs' real transmission costs increased steadily and by three-fold between 2003 and 2023 (\$1.8 billion to \$5.7 billion per year [2024\$]).

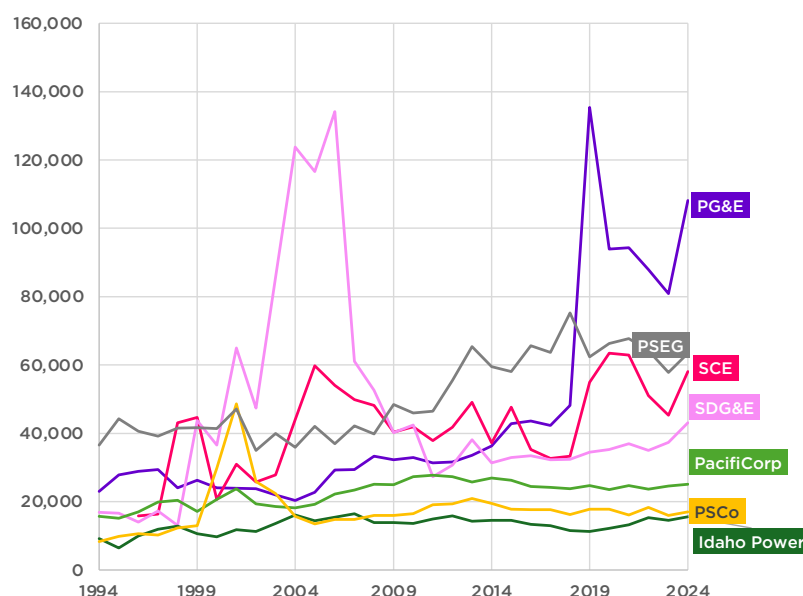
The drivers of transmission cost increases are not clear. FERC regulates most transmission costs and rates, substantially reducing the power of the CPUC and state to control and have visibility into transmission cost drivers. About 50% of transmission investments are self-approved repair and replacement projects that do not create new capacity and are not subject to CAISO review or FERC oversight, though it is not clear how much these investments have contributed to average utility transmission costs. Large policy-driven transmission projects, such as Tehachapi and Sunrise Powerlink, may have also contributed to rising transmission costs. Wildfire prevention costs in the form of O&M began to grow steadily as well after 2018.

California's transmission expenditures are also systemically higher when benchmarked to peer utilities, though by a lower margin than distribution expenditures. California IOUs' annual transmission costs per customer tended to be higher than their peers. PG&E in particular saw unusually high O&M costs for transmission related to wildfire prevention.

FIGURE 4.

Transmission Proxy
Revenue Requirement
Cost per Customer
Account, 2024 USD

(Source: GridLab and
Evolved Energy Research,
2026)



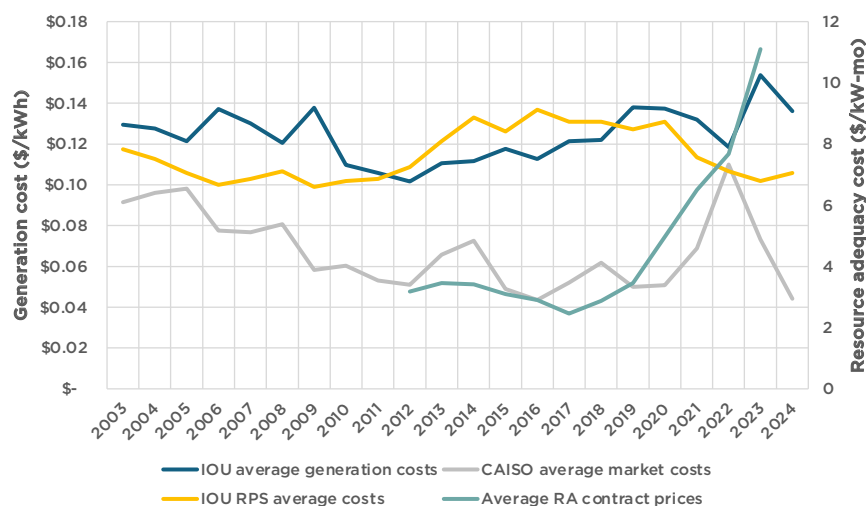
Generation costs

The other large part of customer rates is utility spending on power generation. The IOUs' real generation rates for bundled customers declined by around 20% from 2003–2011 (from \$0.13/kWh to \$0.11/kWh [2024\$]), then increased by 40% between 2012 to 2024 (from \$0.10/kWh to \$0.14/kWh [2024\$]). Generation costs include longer-term and nearer-term power procurement, power procurement from qualifying facilities, and CAISO market energy and ancillary services costs. Although not entirely clear, several factors likely contributed to the increase in IOU bundled generation costs between 2012 and 2024, including a brief increase (2012–2014) in the costs of complying with California's renewable portfolio standard and an overhang of contract obligations as load migrated to community choice aggregators (CCAs). Another contributor factor to increasing costs after 2019 are resource adequacy costs, which have been steadily increasing since 2019.⁴

FIGURE 5.

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

(Source: GridLab and
3rdRail, Inc., 2026)



Systemic drivers

Multiple elements of cost beyond physical infrastructure influence all elements of California electricity rates, and are worth noting as foundation to this report's analysis and recommendations. Some of these are unique to California, while others are drivers affecting the entire industry. These issues and the policies to limit their impact on future rates will be discussed in greater detail later in the report.

- **Wildfire liability:** California law makes utilities strictly liable for property damage caused by their equipment, including wildfires they start, regardless of whether the utility was negligent or imprudent. This dynamic caused PG&E's bankruptcy in 2020, and remains a

⁴ It is worth noting that wholesale energy prices in California are among the lowest of all ISOs, affirming that growth in generation costs is driven by other costs. See, for example, the Energy Information Administration (EIA) regional wholesale markets report (<https://www.eia.gov/electricity/monthly/update/wholesale-markets.php>).

strong incentive for both IOUs to push wildfire risk as close to zero as possible. While utility-sparked wildfires cause damage, the cost of absolute prevention is also increasingly untenable, and ignores the non-utility measures that would limit damage rather than ignition.

- **Utility returns on capital:** All U.S. monopoly IOUs earn a regulated rate of return (ROR) on all capital investments, providing a strong incentive to invest capital in the system under regulator oversight. California IOUs' returns on equity are above average relative to peer utilities, due in part to higher investor perceptions of risk from primarily wildfire liability that require higher cost of capital, exacerbating this dynamic and increasing overall costs relative to their peers.
- **Falling system utilization:** Since 2000 the IOUs' average system load factors — the ratio between peak and average demand — have fallen from just over 60% to below 50%. 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. Some of this is driven by rooftop solar, which reduces total consumption at the customer premises.
- **Ratepayer-funded public programs:** These include the costs of programs required by legislation, comprising between 4-6% of total revenue requirements. California Alternate Rates for Energy (CARE) program, energy efficiency (EE) and low-income EE, and funding for early-stage technology deployment are the large components of ratepayer-funded public programs. Some of these charges, like CARE, explicitly move revenue from one set of customers to another, while others like efficiency or distributed energy resource incentives and procurement promote collective investment in technologies that also impact the total system cost (i.e. they have costs and benefits to consider in addition to distributional impacts).⁵
- **Equipment price increases:** Power sector equipment has increased in cost significantly since 2019, well above the pace of inflation as measured by the Consumer Price Index. Although equipment prices have stabilized somewhat in recent years, current equipment cost increases relative to 2019 prices are 40-130% higher, versus 20% higher if they were consistent with the CPI.⁶

Further explanations of these dynamics are available in the GridLab-commissioned reports previously referenced.

⁵ Another large cost required by policy and legislation includes non-bypassable wildfire charges, but these are not typically included as part of the ratepayer-funded public program category.

⁶ Lawrence Berkeley National Laboratory, July 2026, Retail electricity price trends and drivers: Data update-2026 Edition. See <https://emp.lbl.gov/retail-electricity-price-trends-and-drivers>.

SECTION 2.

What can California policymakers do about it?

In January 2026, Energy Innovation and GridLab held a workshop of 20 California electricity thought leaders to collect and develop systemic solutions that reduce California rates without slowing the energy transition. The group's purpose was not to reach consensus but rather develop innovative policy ideas, leaving the vetting and recommendations to the authors of this report, without attribution. The group focused on solutions in three cost drivers: utility costs (the size of the pie), rates (who pays for the pie), and wildfire (the fastest growing slice of pie).

The two day workshop inspired us with new ideas that match the scale of California's affordability crisis, as well as a framework for addressing rates. This report includes recommendations inspired by this workshop but does not represent a workshop summary. In a few cases it includes ideas that were not discussed at the workshop, which are indicated as such.

Subsequent discussions clearly showed a political and economic imperative to quickly stabilize rates and reduce them as soon as possible. Policymakers must deliver near-term rate relief or risk continued rate increases that further exacerbate untenable costs of living while also making electrification of other sectors an economic impossibility and risking further erosion of public trust.

However, the toolkit for immediate rate relief is limited. Utility capital costs have significant inertia, as do multi-year capital spending plans. Generation costs are mostly locked into long-term contracts with limited competitive options. Utility wildfire liability still looms large, creating pressures for significant investments in ignition risk reduction. O&M costs may have some areas for targeted relief, but must be balanced against utilities' duties to maintain a reliable grid.

At the same time, California's leaders, including its next governor, have an opportunity to fix the structures that got us here — reversing the trend of never-ending increases to utility costs that result in rate increases. Legislative changes, innovative rate designs, and new programs can help, along with internal reforms that promote accountability and more effective regulatory oversight of utility expenditures.

Finally, California faces unprecedented pressure on utility costs from wildfire, but the conditions that got us here — wildfire liability, community exposure, insurance costs — are not set in stone. Nor are they the sole responsibility of the utility regulator to fix. California needs to innovate and act boldly to stop using electric rates to cover the costs of climate adaptation. Since rates are less progressive than either sales or income taxes, doing so acts as a regressive tax on

Solutions for California's Rising Electricity Costs

Policy opportunities on utility oversight and reducing total utility costs



Policy opportunities on allocating system costs fairly



California consumers and undermines the economics of mitigating the climate crisis through electrification.

The recommendations proposed here cover two major priorities for California. The first priority is developing tools and structures that enable more effective regulatory oversight and align utility incentives toward lowering utility costs. We highlight specific opportunities for policymakers to take aim at the size of utility costs through regulatory and legislative interventions. The second priority is ensuring utility rates allocate system costs and risks fairly between customers and utilities, and seek opportunities to reward flexibility. For each opportunity, we identify a rough timeline to implement based on input from the workshop, where applicable.

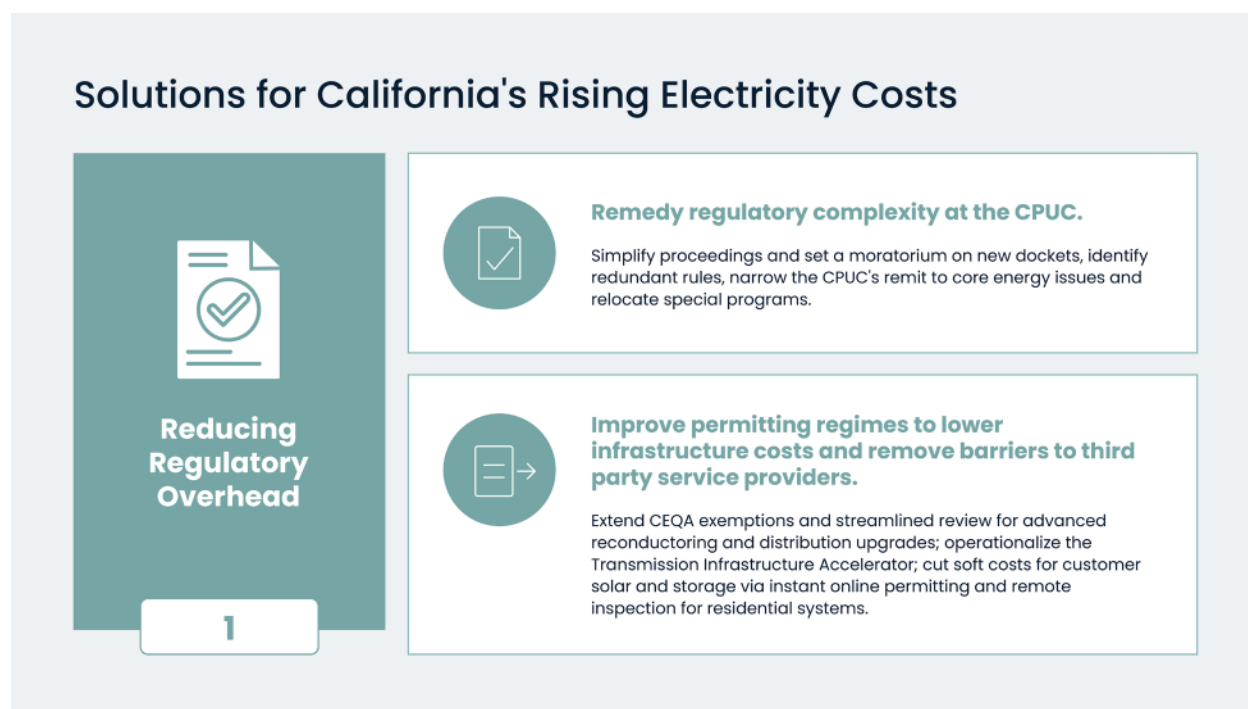
Improving cost oversight and limiting utility costs: regulatory structure and utility incentives

Workshop participants focused on utility costs acknowledged that the structure of PUC regulation itself can hamper effective cost oversight. California's electricity governance and regulatory structure has become extraordinarily complex, difficult to oversee, and poorly

aligned with cost containment. Over time, layered mandates, fragmented proceedings, proliferating utility programs, opaque cost recovery mechanisms, and centralized planning structures have increased administrative burden while weakening transparency, competition, and accountability. The next three sections outline opportunities to address these structural problems by reducing regulatory overhead and simplifying governance, improving transparency and cost oversight through more standardized and accessible reporting frameworks, and realigning utility incentives and planning structures to prioritize affordability, efficient infrastructure investment, and better utilization of distributed energy resources.

FOCUS AREA 1

REDUCING REGULATORY OVERHEAD



California's electricity sector regulatory structure is notoriously complex, with numerous, overlapping legislative mandates and reporting requirements, a multitude of vintage utility programs, arcane accounting rules and frequent changes in accounting practices, copious planning and stakeholder processes, and extensive yet detailed rules for procurement. Excessive complexity makes it difficult to track changes over time and determine reasonable costs – this not only inhibits effective stakeholder engagement because new entrants need guidance on navigating the system, but it also weakens regulatory oversight because the level of intricacy makes it difficult for regulators and stakeholders to focus, set coherent goals, and measure success. The complications of the system as it is, also advantages well-resourced regulated utilities. Not all complexity in these systems can be avoided as some are necessary,

but much of it is needlessly complicated — our goal is to simplify this.

Radical simplification would aid efforts to reduce electricity costs and rates, but it would require rethinking the state’s approach to policymaking and regulation of the electricity industry going forward. Locating regulatory authority in other existing or new agencies could increase administrative costs, further dilute stakeholder energy, or result in mismatched regulatory expertise.

OPPORTUNITY

Reflect on and remedy regulatory complexity at the CPUC

TIMELINE | ~4 years

A few concrete steps examined at the workshop could help the CPUC create a more manageable regulatory structure for its own staff as well as intervenors. First, the governor could direct the CPUC or a third party to create a plan for simplifying proceedings based on interviews and comments from intervenors and utilities. This could be paired with a voluntary moratorium or limitation on legislation that requires new dockets while the review happens. AI tools could be useful in identifying duplicative or conflicting rules, and should be permitted for use by staff and consultants to answer this question. This would result in a report to the legislature recommending legislation that would help simplify CPUC processes and prioritize CPUC resources.

The CPUC, state legislature, legislative advocates, and governor would all have to work together to achieve this simplification, as complexity is the result of a tug-of-war between the legislature and the CPUC. At our workshop, participants pointed to a general frustration between CPUC and legislators: CPUC feels its capacity to effectively regulate is limited by legislative demands that create proceedings that fracture CPUC attention, while the legislature is frustrated the CPUC is not being responsive to popular demands for more reliable, affordable, and equitable energy services. Meanwhile, many stakeholders see new legislation as a primary mode to promote new solutions at the CPUC. A cooperative approach should prioritize new initiatives while creating clear direction and space to eliminate redundant or ineffective programs and approaches.

One solution some participants suggested exploring is limiting the remit of the CPUC to simplify its agenda and focus on utility cost control. One way to do this is to turn the CPUC into an energy-only regulator, while creating new, parallel regulatory authorities for the other constitutionally designated natural monopolies like water, telecommunications, and railroad. Another potential solution is to find areas of CPUC jurisdiction that are not core to economic regulation and delegate them to other California agencies; these may include public purpose programs, innovation grants, efficiency and demand-side management, and others to be determined.

OPPORTUNITY**Improve permitting regimes to lower infrastructure costs and remove barriers to third party service providers⁷**

Outside of regulation, the permitting environment for electrical infrastructure in California could be improved to help reduce the cost of resource deployment. In 2025 the Governor built on efforts to streamline permitting for new clean energy resources by ordering agencies to coordinate and prioritize permits for projects that can start construction before July 2026 when federal clean energy tax credit eligibility ends.⁸ The same executive order directs agencies to deliver recommendations to further expedite clean energy development, which will reveal a pathway to continue making California a premier place to develop clean energy projects.

Beyond generation resources, California's transmission and distribution grid faces distinct permitting bottlenecks that significantly drive up infrastructure costs. To accelerate high-voltage transmission, the CPUC modernized its siting regulations in January 2025 by adopting General Order 131-E. This update streamlined the process by establishing a "rebuttable presumption of need" for projects already vetted by the CAISO, eliminating duplicative regulatory reviews, and allowing applicant-prepared draft CEQA documents to expedite environmental analysis. While General Order 131-E targets procedural redundancies at the CPUC, capturing deeper ratepayer savings requires moving from administrative updates to structural statutory reforms. A critical next step is unlocking existing grid infrastructure through full statutory CEQA exemptions for advanced reconductoring, the practice of replacing legacy wires with high-capacity, advanced conductors within existing rights-of-way. This mechanism allows the state to multiply transmission capacity at a fraction of the cost, bypassing the multi-year environmental loops required for entirely new corridors. In addition, California can further streamline transmission permitting by fully operationalizing the newly established Transmission Infrastructure Accelerator. By forcing state agencies, such as Caltrans and regional water boards, to synchronize their reviews into a strict, parallel "one-stop-shop" timeline, the state can streamline transmission permitting, which directly reduces the costs of these large projects.

It's not just transmission, however, local distribution-level "poles and wires" remain bogged down by fragmented municipal encroachment rules and multi-agency silos. To further compress grid deployment timelines and lower ratepayer costs, California could scale these bulk-transmission successes downward by establishing programmatic CEQA exemptions for distribution line upgrades and standardizing utility-side permitting workflows across local jurisdictions.

California could take a similar approach to customer energy resources (CER), particularly solar and storage. Despite leading the country in deployment of both, developing these projects

⁷ This opportunity was not discussed at the workshop but is proposed by the report authors.

⁸ Governor Gavin Newsom, August 29 2025, Governor Newsom signs executive order to bolster California's clean energy progress in face of Trump's wrecking ball. See <https://www.gov.ca.gov/2025/08/29/governor-newsom-signs-executive-order-to-bolster-californias-clean-energy-progress-in-face-of-trumps-wrecking-ball/>

still costs more than triple the price in Australia. Recent work from Permit Power⁹ provides a useful framework for reducing soft costs, which it finds account for 78% of customer energy resource prices nationwide. Permit Power recommends policymakers focus on three outcomes that track Australia's successes: enabling instant online permitting for standard residential systems, allowing remote inspections to reduce repeat permitting visits, and streamlining interconnection and pursuing it in parallel to permitting and inspection. Reducing CER costs is important for these resources to provide competitive value as compared with utility-scale resources.

FOCUS AREA 2

CONFRONT DISTRUST WITH IMPROVED TRANSPARENCY

Solutions for California's Rising Electricity Costs



Confront Distrust with Improved Transparency

2



Create standard templates for aggregate cost reporting and tracking that facilitate more effective cost oversight.

Create a detailed standardized annual cost-tracking framework for deeper insight into utility spending, demand greater FERC/CAISO oversight and reporting on self-approved transmission projects.



Create a transparent framework for measuring the cost-effectiveness of wildfire risk mitigation spending across agencies and electric utilities.

Develop a common, cross-agency cost-effectiveness framework to prioritize spending on wildfire risk reduction that goes beyond ignition reduction and considers community-scale hardening.

California has enacted robust, sometimes overlapping data sharing mandates that require utilities to generate public reports on a regular basis and submit proposals for public scrutiny. For example, the CPUC has a dedicated website cataloguing its 13 annual reports to the legislature, each of which can be dozens of pages or more. However, despite these efforts to improve transparency and accountability, it is still not clear what factors are driving cost increases or how best to mitigate them.

⁹ Permit Power, 2025, As cheap as our peers: How cutting red tape can lower the cost of rooftop solar and offset rising utility bills. See <https://permitpower.org/wp-content/uploads/sites/35/2025/10/Cheap-as-our-peers-1.pdf>

In some ways, the ocean of data produced by utilities creates a double bind dynamic for regulators, legislators, and intervenors: they need this information to oversee utility costs effectively but they also struggle to process it all for effective oversight without reform. Workshop participants noted that perhaps the wrong data is collected and that too much data lacks clear frameworks for organization and oversight. This shows up in two main venues: planning proceedings and rate cases.

For general rate cases, the principal difficulty in tracking costs lies in the complexity of sorting through digital reams of documents for evidence on the prudence and sources of utility spending. The thousands of pages of utility cost accounting in rate cases make it difficult for intervenors and regulators to gather a comprehensive but manageable picture of what categories are driving utility spending as well as which changes would result in durable savings that won't undermine quality of service. Meanwhile, other categories of spending are increasingly reviewed in separate dockets from the general rate case, such as wildfire, resource planning, distributed energy resources, new utility-owned generation, and transportation electrification.

OPPORTUNITY

Create standard templates for aggregate cost reporting and tracking that facilitate more effective cost oversight

TIMELINE | ~3 years

The legislature has recently created and the CPUC has implemented multiple requirements for utilities to report and project spending in an effort to improve transparency and identify solutions. SB 695 requires IOUs to create quarterly standardized reports on specific categories of spending comprising the total revenue requirement, as well as rate projections for the next 3 years. AB 3264 complements this by requiring annual and ongoing reporting of total energy costs to help the public better understand how utility spending, rates, and fuel switching are all contributing to total customer energy costs across fuels. The CPUC annual reports to the legislature on utility costs, wildfire, and other important categories add to the wealth of materials that can help stakeholders get a relatively full picture of utility costs drivers now and into the future. These data sources were essential to the assessment of cost trends that underpin the first section of this report.

Despite these steps toward transparent reporting, workshop participants noted that while these resources give us a growing sense of the categories of spend that drive costs over time, they tell us less about why costs are rising and what alternatives would be more prudent. To address specific gaps in existing cost reporting, the CPUC could develop a standardized template for projecting and tracking utility costs annually. The template would be designed to enable more effective interventions and oversight in rate cases. The CPUC could hire an independent consultant to help create a template proposal and manage stakeholder input, leveraging expertise of intervenors, staff and utilities at the front end to create reporting requirements that help streamline oversight while avoiding (or eliminating) redundancy in reporting. The

template could draw from existing regulatory reporting processes wherever possible, creating a single consolidated source for cost data. After a year of development, the CPUC could require utilities to submit annual standardized cost reports, which could then be used for rate oversight and as a starting point for follow-on discovery and auditing efforts. The data collected could also be integrated into public reporting tools where valuable.

Workshop participants identified three significant shortfalls in current IOU cost reporting that a standardized template should address. First, cost data should be sufficiently granular to enable regulators and intervenors to understand drivers of year-over-year changes in costs. Reporting categories could be capped by total expenditure, for example 5% of a utility's total revenue requirement. This can be contrasted with SB 695 reporting, where generation and distribution expenditures are lumped into single categories for the most part, even though they are the largest line items in the report. Second, cost reporting should be consistent across utilities and over time to enable easy comparison between different IOUs and to clearly identify changes in a given cost category over time. This is in contrast to FERC Form 1 cost reporting, which includes a high level of granularity but allows so much utility discretion in how to categorize costs that individual line items swing widely year-over-year, making it difficult to identify trends or understand root causes. Third, the reporting template should identify select costs that can be reported on a per-unit basis, allowing more meaningful cost benchmarking across utilities and over time. Different cost categories would require customized approaches to unitization, such that per unit costs may not be practical to include for all categories. Stakeholders would identify a subset of large or otherwise significant cost categories and develop consistent unitization practices for each. For example, distribution undergrounding cost reporting could include miles of line undergrounded; substation expansion costs could report added capacity; distribution vegetation management could report miles of line cleared.

One additional area worth tracking and demanding better oversight from FERC is self-approved transmission projects. These projects proceed outside of CAISO planning processes and FERC oversight when they are for specific pre-approved uses such as asset replacement, local reliability, maintenance, safety, or like-kind rebuilds. From the CPUC's 2025 utility cost report:

According to the most recent data in the CPUC's Transmission Project Review (TPR) Process, between 2020 and 2024, of the total \$11.7 billion in transmission capital expenditures by the three IOUs, \$8.7 billion (about 75% was invested in self-approved projects that received no formal review and approval in their planning by the CAISO.

The CPUC and incoming governor should devise further strategies to elevate this growing expense category at FERC, including advocacy through multistate forums like the National Association of Regulatory Utility Commissioners.

OPPORTUNITY**Create a transparent framework for measuring the cost-effectiveness of wildfire risk mitigation spending across agencies and electric utilities****TIMELINE | ~2 years**

Utility spending on wildfire-related costs is surging as California's utilities work to reduce the risk of igniting catastrophic wildfires. California's IOUs are spending nearly \$9 billion per year on wildfire-related costs, mostly reducing utility-caused ignition.¹⁰ Spending on other forms of wildfire mitigation across other agencies is just a fraction. For example CalFire's mitigation budget for the most recent year is just \$440 million, and spending on wildfire and forest resilience activities across agencies are expected to total \$3.6 billion over eight years.

The state must be able to make more effective spending decisions, allocating resources where they do the most to reduce the risk and consequence of catastrophic wildfires. SB 254 improved the current planning process for utility wildfire plans, explicitly requiring an evaluation of cost per avoided ignition in consideration of utility wildfire mitigation plans, while coordinating wildfire mitigation plan review by OEIS with the utility rate case cycle at the CPUC. But a common framework across wildfire related spending and community risk reduction state-wide does not exist.

Building on the improvements from SB 254, California could create a transparent framework for measuring the cost-effectiveness of actions taken to reduce catastrophic wildfire risk with a strong focus on community wildfire risk reduction, to support allocating resources where they can do the most good. In developing this framework, the state should actively question the extent to which wildfire threat reduction is best accomplished through utility programs and ratepayer-supplied funding. This is an opportune moment to identify the most impactful approaches to wildfire safety beyond ignition reduction (e.g., community-scale wildfire hardening) and to actively question which entities are best positioned to execute on a more robust wildfire strategy. In addition to helping the state decide where to allocate resources, creating a state wildfire mitigation framework could also give regulators more robust tools to review proposed utility spending.¹¹

10 California Public Utilities Commission, September 2025, 2024 California electric and gas utility costs report: AB 67 annual report to the governor and legislature. See https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/ab67_puc913_102425.pdf.

11 The SB 254 study report from April 2026 presents similar recommendations regarding a focus on community wildfire risk reduction and fair allocation of cost burdens to mitigate wildfire risk. California Earthquake Authority. (2026, April 7). Enhancing California's resiliency to natural catastrophes: Senate Bill 254 (2025) study report. <https://www.cawildfirefund.com/sites/wildfire/files/documents/2026/sb254-natcatresiliencyreport-locked-4-7-26.pdf>

FOCUS AREA 3

ALIGN UTILITY INCENTIVES WITH AFFORDABILITY

Solutions for California's Rising Electricity Costs



Align Utility Incentives with Affordability

3



Put investor-owned utilities on a budget.

Consider a revenue cap linked to limited, predetermined adjustments (e.g., inflation), paired with folding riders/balancing accounts back into base rates to preserve cost-containment incentives.



Tie financial performance to affordability targets.

Assess current incentive frameworks, require reporting on affordability and metrics like grid utilization. Over time, link a portion of authorized return on equity to meeting affordability/ cost-savings goals.



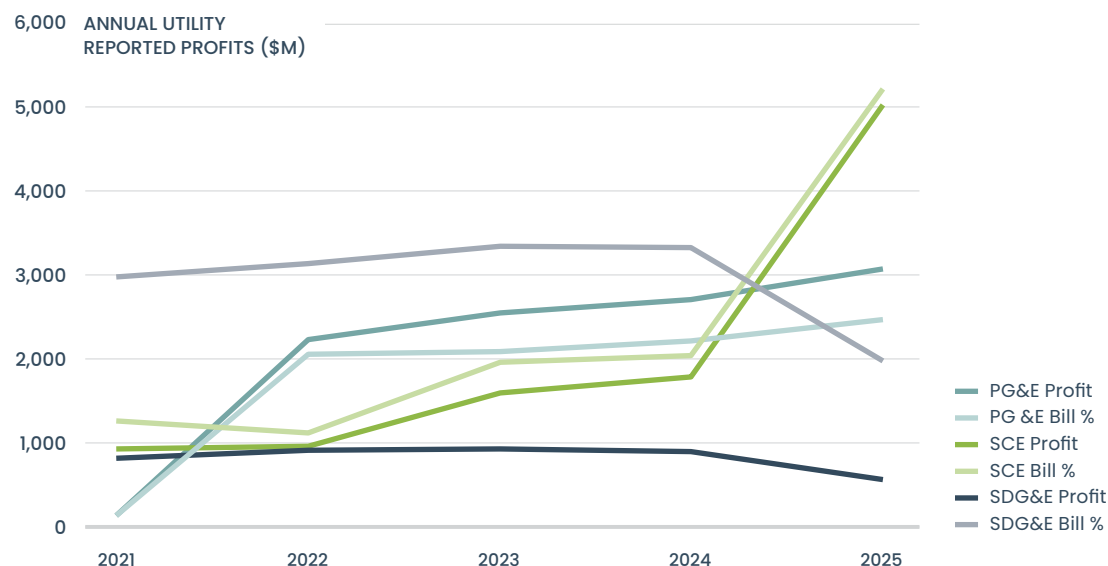
Limit excess utility profits.

Consider an earnings sharing mechanism that refunds a share of earnings exceeding authorized return on equity by a set margin like Hawaii, Massachusetts, Minnesota, New York, and North Carolina.

Amid rapidly rising electricity rates, IOUs' reported profits (net income in public financial statements) have on average increased steadily since 2021. Profit increases in recent years have outpaced rate increases.¹² Of course, 2021 was a natural low-point with the PG&E bankruptcy and ongoing wildfire insurance expenses that cut into utility profits statewide; however, the trend is clear: as rates increase, utilities in California are not seeing declining profits.

¹² Energy and Policy Institute, EPI Utility Profit Tracker, <https://energyandpolicy.org/utilityprofittracker/>

FIGURE 6. California IOU Profits (2021-2025)



In competitive markets, competition forces businesses to respond to consumer needs or preferences for lower cost products – profits are a built-in incentive to reduce cost. IOUs face no such competitive pressure, although regulation is meant to be a proxy for it. This presents an opportunity for an accountability reset that better aligns utility incentives towards what California consumers want: an affordable, clean, reliable, and safe electricity system.

OPPORTUNITY

Put investor-owned utilities on a budget¹³

TIMELINE | ~3-5 years

Today, utilities' total revenue requirements emerge from a complex process that forecasts and adjusts expenditures over a four-year period, the framework for which is determined in each general rate case. The current framework sets utility rates based on an expected revenue requirement, but does not currently act to constrain utility costs in a meaningful way.

One option for doing so might be setting a comprehensive cap on utilities' allowed revenues (a "revenue cap") tied to an external index to incentivize utilities to contain costs by better utilizing existing assets and resources, making more strategic investments, and prioritizing spending in areas that support customer needs and policy goals. Instead of being based on forecasts, a revenue cap would be restricted to only limited, pre-determined annual adjustments, such as inflation, outside of general rate cases.

¹³ This opportunity was discussed at the workshop but the specifics of revenue cap design were not discussed. There are a multitude of design considerations which have tradeoffs worth considering if policymakers choose to go down this route.

However, the strength of an externally-indexed revenue cap's efficiency incentives will depend on the extent utility costs are recovered through base rates. Right now, the IOUs have hundreds of balancing and memorandum accounts and other riders that track specific costs and recover them from customers over time. These costs are treated separately from costs recovered through base rates, which are subject to review in a general rate case — by contrast, each individual balancing account or rider is subject to individual review outside the rate case. The number of riders in California have rapidly expanded over the last decade, making it difficult to understand which mechanisms recover which costs and their aggregate rate impact. While riders historically were only implemented for limited use cases, they have slowly become the default approach to cost recovery in California. It is worth noting California is not unique in this regard; utilities have been successful at increasing the use of trackers and balancing accounts nationwide to reduce revenue uncertainty and recover specific costs.¹⁴

A recent report from the UC Berkeley Center for Law, Energy, and Environment (CLEE) details the basic problem: "Alternative ratemaking mechanisms like tracking accounts distort traditional cost-of-service ratemaking by removing an incentive for utilities to find cost efficiencies."¹⁵ The same report suggests the state legislature and CPUC could limit the use of single-issue ratemaking mandates and tracking accounts, absent extraordinary circumstances.

Implementing CLEE's recommendation is essential to ensuring a revenue cap conveys the correct incentives. The CPUC should consider which of these riders can be integrated back into base rates to simplify the number of cost recovery processes, ensure adequate regulatory review and oversight, and subject more utility costs to the efficiency incentive of a revenue cap. The CPUC needs to consider all spending on a cumulative and coordinated basis. Any expenditures in excess of inflation should receive additional scrutiny. This may also require legislative shifts since some of these tracking accounts were created through legislation. For riders that remain outside a revenue cap, the CPUC should consider what other mechanisms could be used to cap spending or otherwise incentivize cost containment. For example, states have deployed strategies to reintroduce the risk of disallowance for tracked costs by allowing only a certain percentage of tracked costs to be passed through to customers while the remaining percentage of costs is reviewed in the next rate case. Other states have created shared savings/risk mechanisms to incentivize more efficient spending under cost trackers.¹⁶

14 RMI, March 19 2026, A Smarter Approach to Cost Trackers to Support Affordability. See <https://rmi.org/resources/cost-trackers-to-support-affordability/>

15 UC Berkeley Center for Law, Energy & the Environment, 2026, Powering down prices: Policy solutions to lower California's electricity rates. https://www.law.berkeley.edu/wp-content/uploads/2026/06/Powering-Down-Prices_CLEE-Report_June-2026.pdf

16 RMI, March 19 2026, A Smarter Approach to Cost Trackers to Support Affordability. See <https://rmi.org/resources/cost-trackers-to-support-affordability/>

OPPORTUNITY**Tie financial performance to metrics and targets that improve affordability****TIMELINE | ~2-4 years**

The CPUC should also consider which additional targeted utility incentives could support affordability. Financial rewards or penalties could be designed to tie a portion of utilities' ROE to meeting affordability targets, or implementation of other intermediate cost-saving measures. For example, performance incentive mechanisms (PIMs) could provide penalties when customer rates increase beyond a certain percentage or provide rewards when utilities pursue lower-cost solutions to meeting grid needs (such as non-wires alternatives). Alternatively, PIMs could target improvement on metrics that are associated with rate reductions, such as improved grid utilization.

If the CPUC authorizes additional earning opportunities, it would first need to consider what adjustments would be necessary to setting the utilities' authorized return on equity to not unintentionally reduce or eliminate the customer rate savings resulting from new PIMs, while also ensuring there aren't sacrifices to quality of service or utility financial health. It's important to ensure utilities are still able to earn a fair return and raise the capital necessary to provide safe and reliable service but their profit margins would be impacted by their performance in these critical areas.

Implementing PIMs requires beginning some no-regrets measures that simply improve transparency on utility performance in key areas. Established best practices for performance incentives includes taking stock of current utility incentives under current regulation and developing new and taking stock of existing performance metrics that address affordability. For example, before implementing its performance-based ratemaking framework, the Hawaii PUC required its largest IOUs to publish annually more than a dozen performance metrics on a public dashboard, helping to highlight where performance improvements were needed.

OPPORTUNITY**Limit excess utility profits****TIMELINE | ~2 years**

To reduce the financial risk to customers from utilities overearning, the CPUC should implement an earnings sharing mechanism (ESM), which functions by refunding part of a utility's "excess" earnings to customers. Typically, earnings are only considered excess once the company's realized ROE deviates from the authorized ROE by a certain amount (e.g., 100 basis points [bps] above). Many states that have multi-year rate plans also have ESMs in place, such as Hawaii, Minnesota, New York, and Massachusetts.

Allocating system costs and risks fairly between customers and utilities

Rising electricity rates don't just reflect an inability to control overall costs; they also reflect intentional decisions as to who should pay for these costs. Rate increases are not inevitable, nor are current trends irreversible, but they require political leadership. High portions of California costs collected based on usage undermine electrification goals while exacerbating disparate energy burdens between rooftop solar adopters and non-adopters. California's decision to place the cost of wildfire risk mitigation on all ratepayers while underutilizing community risk mitigation approaches tilts mitigation costs towards utilities and away from communities and taxpayers, driving up rates. And inadequate attention has been paid to improving efficient use of the grid and reversing California's 20-year trend of falling grid utilization. The following section explores innovative approaches to improve the allocation of costs and risks between stakeholders, drawing on some of the innovative proposals surfaced at our January workshop.

FOCUS AREA 4

MODERNIZE ELECTRICITY RATE DESIGN

Solutions for California's Rising Electricity Costs



Modernize Electricity Rate Design

4



Adjust rates to reflect modern priorities for the electricity system including improved utilization, electrification, and equity.

Build on the income-based Base Service Charge, expand summer baseline/supplemental credits for hot-climate customers, design rates that lower marginal costs for electrification, transition legacy rooftop solar customers to fair and modern rates.

OPPORTUNITY**Adjust rates to reflect modern priorities for the electricity system including improved utilization, electrification, and equity**

For decades, residential electricity rates for California's large IOUs have relied on volumetric rates (cents/kWh) to recover most or all electricity costs. Historically, fuel costs were a major driver of electricity costs, and thus conservation was a key strategy to reduce costs and lower emissions. Volumetric pricing was intended to support conservation and make energy efficiency measures more cost-effective. In addition, low-income customers were understood to be smaller-than-average electricity users, so volumetric pricing was also thought to support energy affordability for these customers.

Today, shifts in grid costs, customer usage patterns, policy objectives, and technology availability have changed the picture:

- Fuel costs are now a small and declining share of electricity costs, while larger cost components include distribution and transmission infrastructure, wildfire mitigation, and near-zero-marginal cost resources like solar and batteries.
- Customer usage has changed: the smallest users today are customers with rooftop solar, while high electricity use is correlated with factors beyond income such as climate, occupancy, and electrification.
- On the policy front, building and vehicle electrification are increasingly seen as crucial measures for both decarbonization and energy conservation. Heat pumps and EVs require low volumetric pricing to be cost-competitive with fossil fuel alternatives.
- Residential customers increasingly have access to flexible technologies such as electric vehicles, home batteries, smart thermostats, smart water heaters, and others.

To support California's policy goals, residential rates must evolve to more equitably allocate costs across customers, to better support electrification, and to create efficient price signals for peak reduction, load shifting, and beneficial off-peak load growth.

A number of changes could help support policy goals:

- **Continue improving the Base Service Charge (Timeline: ~three-five years).** The income-based fixed charge proceeding aimed to advance three goals: to better align electricity rates with underlying costs; to improve affordability, particularly for customers with the highest energy bills; and to better support electrification of vehicles and buildings. In many regards, the effort was a success: the \$24/mo Base Service Charge lowered volumetric rates by 5–7 c/kWh and expanded discounts for CARE customers. While many stakeholders were comfortable with larger fixed charges for high-income customers, challenges related to income verification for utility customer accounts have yet to be resolved that would enable a more nuanced income-based fixed charge.
- **Support customers with high summer air conditioning demand (Timeline: ~two years).** While customers across the IOU service territories see high electricity bills, customers in hot

regions of the state can face extraordinary summer bills to maintain safe temperatures in their homes, with summer electricity bills of \$500/month or more being within the norm. While the base service charge was an important step to reduce volumetric rates and help manage these bills, other tools may also play a role. Baseline credits are one potential option. These credits create the “two-tier” structure in default rates. In current practice, baseline amounts vary based on climate zone and by season. This existing rate element could be tuned to increase the summer baseline allowances for hot climate zones, which would provide a discount on summer bills; this would deliver greater summer discounts in hot climates, supporting affordability for customer groups with the highest bills. Another option is to provide supplemental summer credits to offset high bills for customers in hot climate zones, for example using the Climate Credit, the return of some Cap-and-Invest (formerly Cap-and-Trade) funds to ratepayers.¹⁷

- **Develop rates that support electrification (Timeline: ~four years).** While the base service charge was an important step, high volumetric pricing continues to be a barrier for cost-effective electrification. Improving the cost-effectiveness of electrification fairly will require continued rate reforms that reduce marginal service costs, such as greater fixed charges, lower off-peak pricing aligned with low-cost hours for the system, and/or other approaches.¹⁸ A novel approach would be to support electrification through greater baseline allowances or another form of monthly credit for electrifying customers, leveraging tax incentives to reduce monthly energy bills and ease the cost for newly electrified customers. This approach could be tied to analyses of system and ratepayer benefits from electrification, and thus could include a requirement for load management to avoid peak impacts from new electric loads. Alternatively, the benefits of electrification could be used to justify upfront incentives for electric equipment.
- **Develop more fair and modern rates for legacy rooftop solar customers.** While this topic was not the subject of our workshop or a primary focus of this report, legacy Net Energy Metering customers have seen the returns on their investment increase dramatically as rates increased. California has more than 1.5 million legacy rooftop solar customers currently receiving full net energy metering at the retail rate, i.e., 30–40 cents/kwh, many of which installed within the last decade, meaning NEM will endure through the 2030s. Relative to other high-rooftop-solar markets like Australia and Germany, California was slow to reform its pricing to align with wholesale prices, reduce lock-in, or to incent self-consumption over exports—all of which were partially accomplished in 2023’s NEM 3.0 (“Net Billing Tariff”) reform. Other markets like Australia and Germany show an opportunity

¹⁷ To this end, an ongoing CPUC proceeding is considering changes to the semiannual Climate Credit to better support affordability. A CPUC Decision in May 2026 updated the timing for the credits to occur in August and September, aligned with the timing of highest customer electric bills. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M605/K823/605823091.PDF>. Future phases of the proceeding will consider whether credit funding should be reserved for a subset of customers such as CARE/FERA customers or given only to customers in hot climate zones. In addition, overall electric Climate Credit funding may increase over time as gas Climate Credit funding is transitioned to electric utility customers.

¹⁸ A new CPUC OIR dated April 10 2026, “Order instituting rulemaking on California advanced electric rate design” will consider several of these options. See <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K677/604677976.PDF>

to strike a new, sustainable balance between the ability to finance solar, competitive pressure on the price of rooftop solar, removing barriers that ease the cost of installation, and windfalls due to rising rates. California could explore developing cost reduction goals for distributed solar that help sustain customer adoption with lower compensation and examine options to offset the cost shift caused by legacy NEM customer export credits in order to get rate increases for all customers under control.

Multiple CPUC proceedings are active on these fronts. As described above, the Commission has an active rulemaking on changes to the California Climate Credit (R. 25-07-013). In addition, the CPUC recently launched a new proceeding on Advanced Electric Rate Design (R.26-04-009), which aims to tackle many of these questions as well as rate design topics for large load customers.

FOCUS AREA 5

REDUCING THE ROLE OF ELECTRICITY RATES TO PAY FOR CLIMATE MITIGATION AND WILDFIRE PREVENTION

Solutions for California's Rising Electricity Costs



Reduce the Role of Rates in Funding Climate Mitigation and Wildfire Prevention

5



Rebalance wildfire mitigation costs toward beneficiaries, including utility shareholders, communities most threatened, and California taxpayers.

Expand ratepayer-backed securitization and explore blended funding from property tax revenues, municipal bonds, and insurance-funded mechanisms to share costs beyond ratepayers.

California ratepayers — not the utilities themselves — are carrying the weight of investments to reduce wildfire risk across the state. These investments create broad social benefits by reducing devastating wildfire losses, but also provide significant private benefits in mitigating utilities from liability for fires their equipment ignites, which in turn improves investor returns. It's fair to ask how these costs should be distributed. As it stands today, utilities seek cost recovery for



expenses and return of and return on investments incurred as they implement approved wildfire mitigation plans.

OPPORTUNITY

Rebalance the costs of mitigating wildfire risks toward the beneficiaries, including utility shareholders, most vulnerable communities, and California taxpayers

TIMELINE | ~six months to four or more years¹⁹

Several reforms could help reduce the cost of mitigating wildfire risk while more fairly allocating costs. The first is limiting utilities' earnings from wildfire-related costs, which could include funding prudent capital investment in wildfire mitigation through ratepayer-backed bond securitization, to finance those investments off the utility's balance sheet and without the utility's authorized return on equity. SB 254 expanded authorization to use securitization for wildfire mitigation investments by \$6 billion through 2035, enabling broader use of the tool in this context but still only covering a small fraction of planned wildfire capital spending over time.

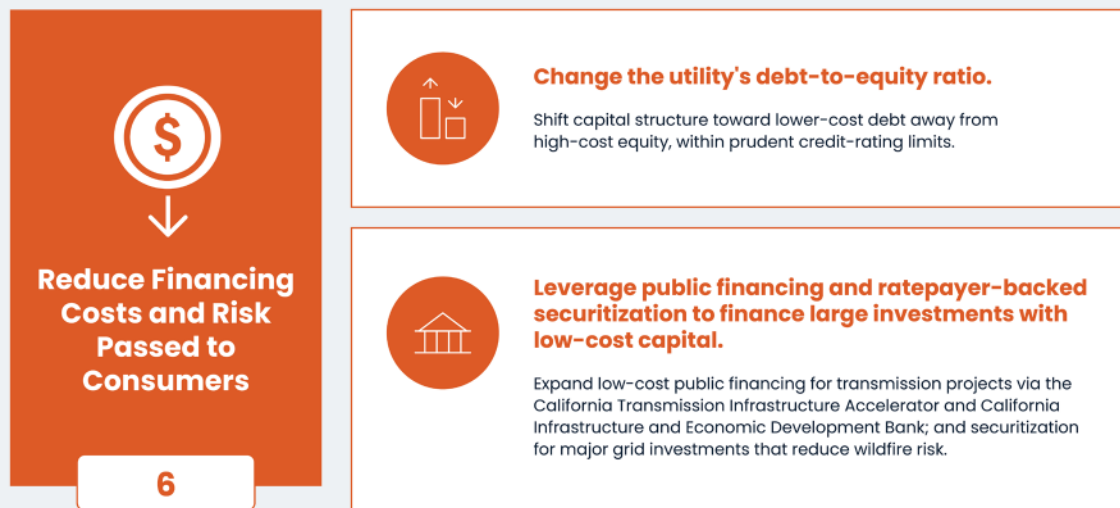
Beyond this, opportunities exist to bring in other funding streams to share in the costs of mitigating wildfire risks. While these opportunities require more development, they could include state or municipal wildfire hardening bonds, insurance-funded mechanisms that offset insurers risk exposure, property tax revenues linked to wildfire risk exposure, or even non-ratepayer-funded utility investments that help lower utility liability for ignited wildfires. In our convening, participants discussed the creation of a "blended" fund with multiple sources that had a mandate to pursue investments that delivered the greatest reduction in risk (of both ignition and consequence) of wildfire per dollar spent while shifting some of the burden off utility ratepayers.

¹⁹ Timelines discussed were ~ 6 months–1 year for blending financing through securitization and more than 5 years for blending financing through taxes, bonds and other mechanisms.

FOCUS AREA 6

REDUCE FINANCING COSTS AND RISK PASSED TO CONSUMERS

Solutions for California's Rising Electricity Costs



According to the CPUC's 2024 cost report to the legislature, "between 2014 and 2024, the utilities' rate bases increased in size from \$48.3 billion to \$97.0 billion, or a 101% increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements." Utilities raise capital from investors and lenders to make these rate based investments in the electricity system, and a portion of California ratepayers' bills goes to pay interest on bonds and loans and provide a return to equity investors in California's investor-owned utilities — the authorized rate of return. An adequate return is needed to attract investment, but how much return is actually needed is a contentious and highly litigated proceeding.

In addition to questions of the right level of returns to authorize for utility investments, there are alternative ways of structuring investment in the electricity system that may deliver lower financing costs.

OPPORTUNITY

Change the utility's debt to equity ratio

TIMELINE | ~4 years

Utilities often finance around half of their capital needs with debt, and half with higher-cost equity. Debt interest rates are typically much lower than authorized equity returns. For California's three electric investor-owned utilities, the cost of debt is roughly half the authorized

return on equity. This differential is exacerbated by the fact that California's IOUs earn higher-than-average equity returns, in part, due to higher wildfire liability risk. Additionally, utility equity returns trigger federal and state tax obligations that are separately charged to ratepayers and raise the cost of equity by approximately 40%.

This creates opportunities to lower overall financing costs by increasing the amount of debt in the utility's capital structure. This requires a careful optimization, as higher leverage can impact credit ratings and drive modest increases to borrowing costs. However these modest increases may be significantly outweighed by avoiding higher-cost equity. Some intervenors in PG&E's cost of capital proceeding have recommended higher debt ratios as a means to lower overall financing costs.²⁰

OPPORTUNITY

Leverage public financing and ratepayer-backed securitization to finance large investments with low-cost capital

TIMELINE | ~2 years

Beyond the utility's own balance sheet, policymakers have several ways to enable lower cost capital to finance needed grid investments. SB 254 established the California Transmission Infrastructure Accelerator to plan and coordinate needed transmission investments, and enable public financing for those investments in coordination with the California Infrastructure and Economic Development Bank. This enables transmission investments with lower debt costs, more debt in the capital structure to replace high cost equity, and potential tax benefits for projects.

In addition, SB 254 expanded existing mechanisms for securitization, using ratepayer backed bonds to finance an additional \$6 billion in wildfire risk mitigation at a lower financing cost than the utility's balance sheet. California can consider broadening the application of this approach to larger parts of utilities' existing and growing wildfire expenditures. Overreliance on this approach can have downsides, including crowding out deeper reforms, increasing the number of non-bypassable charges on customer bills, weakening utility accountability, and deferring near-term one-time expenditures to future generations.

Public financing mechanisms have significant potential to lower the cost of capital for the grid, critical at a time when large capital investments are needed in the transmission and distribution systems to address wildfire risk, meet growing load, replace aging equipment and decarbonize the grid. Public financing for the grid is not a panacea however; it should follow and support an improved planning and regulatory process that ensures funded projects are needed and beneficial to the public, and result in lower overall costs for customers. But with good oversight, public finance can drive significant savings for customers.

20 CPUC Proposed Decision, November 14, 2025, Decision addressing test year 2026 cost of capital for Pacific Gas And Electric Company, Southern California Gas Company, Southern California Edison Company, And San Diego Gas & Electric Company. See <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M587/K323/587323962.PDF>



FOCUS AREA 7

ENCOURAGE CUSTOMER FLEXIBILITY & IMPROVE GRID EFFICIENCY

Solutions for California's Rising Electricity Costs



**Encourage
Customer
Flexibility &
Improve Grid
Efficiency**

7



Combine state electrification incentives with program and rate designs that make electrification affordable and flexible.

Link vehicle and building electrification incentives to enrollment in demand response and flexible charging programs.



Leverage flexible large loads to improve utilization and lead on industrial electrification.

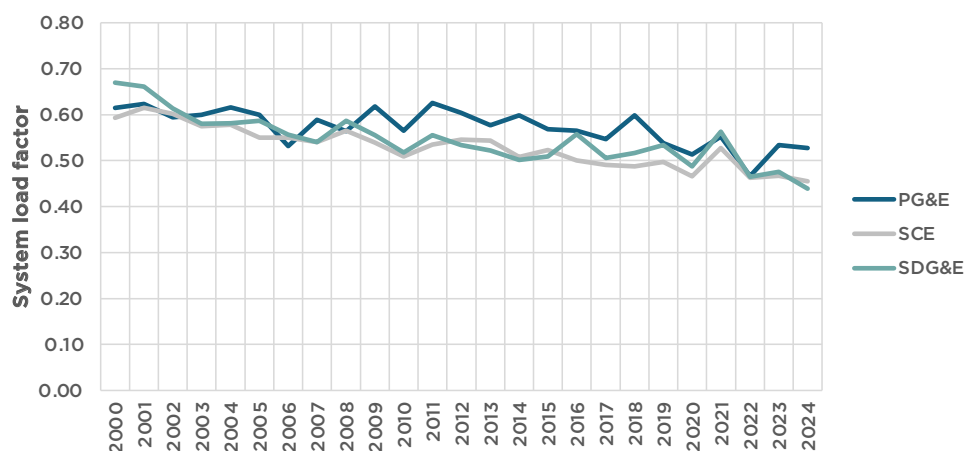
Use flexible grid connections to attract industrial load that improve system utilization, coupled with careful rate design to ensure costs are not shifted to other customers.

Grid infrastructure, once built and approved by regulators, generally is recovered in rates over the lifetime of the assets. These investments are sized to serve peak load. If peaks grow while average usage stays flat, the “load factor” — the ratio between average and peak load — falls. When rates are largely volumetric, falling average load factor means higher volumetric rates for the same infrastructure. Overall, California’s system load factor has fallen from between 60–70% in 2000 to 45–55% in 2024.

FIGURE 7.

System load factors in the PG&E, SCE, and SDG&E planning areas, 2004–2024

(Source: GridLab and 3rdRail, Inc., 2026)



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.

The electrifying buildings, vehicles, and industry (particularly data centers, if managed well) presents an opportunity to reverse this trend, but high rates undermine customer confidence that electric options will save money. California must find a way to grow load capacity not just to meet its climate goals but as a strategy to improve grid utilization, flexibility, and reliability.

OPPORTUNITY

Combine state electrification incentives with program and rate designs that make electrification affordable and flexible

TIMELINE | ~2 years

California’s authority to continue promoting electric vehicles through sales mandates has been called into question by recent U.S. Environmental Protection Agency repeals and Congressional revocation. With a smaller toolbox, California has to use the options available to promote beneficial electrification, which includes ensuring electricity rates are aligned with this goal. This can ensure that customers can afford electric vehicles and have easy ways to contribute to the imperative to improve utilization of the grid.

As California develops its new policies, leadership can help promote wider deployment of flexible charging by linking vehicle purchase incentives to enrollment in utility or aggregator demand response and flexible charging programs. The same is true for building equipment — upfront incentives can be paired with enrollment in demand response programs. Incentives could even be delivered through electricity bills — pairing new electrification with instant bill savings made more durable through grid-beneficial use of electrified cars and home heating.

OPPORTUNITY**Leverage flexible large loads to improve system utilization and lead on industrial electrification****TIMELINE | ~2 years**

Although this opportunity was not extensively discussed in the workshop and may not be central to lowering rates for existing customers, California's overall economic future depends, in part, on its ability to attract and retain diverse industrial activity. However, California's industrial rates currently serve as a major deterrent to industrial electrification and new industries (including data centers) coming to California and helping improve usage of grid infrastructure. For example, PG&E reports industrial customers see bundled total rates between 17–28 cents per kWh — well above the national average of nine cents. By contrast, average wholesale rates in CAISO are closer to three cents per kWh, due in large part to solar driving down prices in the middle of the day. California could lead in creating opportunities for flexible industrial loads to access clean energy and improve utilization of the grid. Flexible grid connection or other mechanisms could be used to access load flexibility and to minimize transmission and distribution upgrades; cost allocation frameworks would need to be developed carefully to ensure costs are not shifted to other customers.

While flexibility of data centers opens the door to tariff reforms that enable flexible interconnection, a proactive approach aimed at providing clean, cheap, variable power directly to flexible industry lays the groundwork for affordable industrial electrification and improved grid utilization in the long run. California can promote deployment of flexible industry through rate design, demonstration projects, and facilitated project development that welcomes new flexible industry and retrofits to existing factories, marrying companies that provide mutual benefit. For example, several long-duration battery companies started in California can help enable conversion of variable, cheap electricity into baseload heat or electricity for low- and medium-temperature industry, but only if industrial rates account for new operational realities.²¹

²¹ Energy Innovation, 2023, Thermal batteries: decarbonizing U.S. industry while supporting a high-renewables grid. See <https://energyinnovation.org/report/thermal-batteries-decarbonizing-u-s-industry-while-supporting-a-high-renewables-grid/>



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