# CPUC Response to Executive Order N-5-24

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California Public
Utilities Commission

Thanks to:

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# Preface

The California Public Utilities Commission (CPUC) appreciates the opportunity to respond to Governor Newsom's Executive Order N-5-24. The Governor's Executive Order sets forth an imperative to mitigate the rising costs of electricity service in California. The CPUC shares this sense of urgency and resolve. In the CPUC's annual SB 695 Report, the CPUC provides an analysis of rates and forecasts of rate trends, and for several years has taken actions within the CPUC's authority to mitigate rising costs for ratepayers.

Executive Order N-5-24 requests the CPUC to:

- Examine the benefits and costs to electric ratepayers of programs it oversees and rules and orders it has promulgated pursuant to statutory mandates that may be unduly adding to electric rates, or whose funding might more appropriately come from a source other than ratepayers. Report to Governor Newsom by January 1, 2025, the results of its analysis and its recommendations for modifying or repealing any statute that would reduce costs to electric ratepayers without compromising public health and safety, electric grid reliability, or the achievement of the State's 2045 clean electricity goal and the State's 2045 economywide carbon neutrality goal.

- Take immediate action under existing authorities to modify or sunset any underperforming or underutilized programs or orders whose costs exceed the value and benefits to electric ratepayers. The commission is requested to return any unused funds collected from ratepayers for underperforming programs and utility investments in the form of a bill credit, if it identifies such funds.

- Consult with California Air Resources Board on options to maximize the effectiveness of California's Climate Credit-which returned an average of $71 to electric ratepayers on their utility bills this fall. Options to improve the credit, particularly for low-income Californians, should be reported to me by January 1, 2025.

- Consult with the Office of Energy Infrastructure Safety on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers. Proposals for legislative or regulatory changes should be reported to me by January 1, 2025.

- Pursue, and direct the regulated utilities to pursue, all federal funding opportunities that can help reduce and avoid electric service costs that would otherwise flow into electric ratepayer bills.

# Introduction: Affordability and Clean Energy Success Is Threatened by Rate Impacts

## California's Climate Goals in the Energy Sector: A Success Made Possible by Utility Ratepayers

California's climate goals have clean energy as a centerpiece. From 2002 when the state adopted its first Renewables Portfolio Standard (RPS) requirement, utility ratepayers have funded major clean energy achievements. The vision for economywide carbon neutrality is now set forth in the California Air Resources Board's Climate Change Scoping Plan, and the electricity sector is on track to achieve greenhouse gas emissions reductions to achieve the ambitious goal of carbon neutrality by 2045.

The California Constitution and the Public Utilities Code spell out how utility customers have funded this success. The Legislature directs the CPUC, who in turn directs the retail electricity providers (load serving entities) to purchase utility-scale least-cost, best fit clean electricity resources on behalf of their customers. This structure has resulted in cost-competitive clean energy achievements that lead the world.

All new procurement today is emissions-free. What's more, prices for solar, wind, and battery storage that are shared among customers on our interconnected bulk system are decreasing every year.

This is the ratepayer funded clean energy success story of California.

At the same time, California's transportation, buildings and industrial sectors are transitioning away from fossil fuel-supplied energy sources. Electricity is already playing a larger role in powering the economy and addressing the climate crisis demands further expansion of electrification.

However, as the Governor's Executive Order recognizes, electricity ratepayers are now experiencing rising bills due to a number of factors, including the impacts of climate change, and many Californians are struggling to bear the burden of increased costs.

In this report, the CPUC responds to the Executive Order by putting the costs of these programs in context with the total scale of IOU revenue requirements, describes the mechanisms by which these costs are created and shared between customers, and identifies ways that the Legislature and the CPUC can work to improve affordability.

## Conclusions in This Report: Options Exist to Save Ratepayers Money Going Forward

Inequitable rate structures and the need for unprecedented climate impact related investments have created a perfect storm driving electricity rate increases. In addition to creating financial hardship, continued rate inflation will put stress on meeting the states climate goals. Electrifying the transportation, building and industrial sectors are critical decarbonization strategies that become increasingly difficult with every increase in electricity rates.

Three areas present opportunities to control costs and reduce electricity bills: first, identifying opportunities to control the growth in utility spending. Second, identifying any opportunities for cost sharing. Third, implementing equitable rates to recover approved costs for wildfire mitigation, public purpose programs and the fixed costs of the grid.

The CPUC's SB 695 report has identified the biggest drivers of rate increases: the growth in spending to address wildfire mitigation and the cost shift that results from legacy Net Energy Metering programs. Secondarily, energization and energy transition related investments in transmission and distribution infrastructure are also putting upward pressure on rates.

This report concludes with strategies that address these costs to save ratepayers money going forward:

1. All energy-related mandates should be assessed for overall cost-effectiveness with the goal of achieving the lowest possible rates for all customers of each utility.
2. Supplement essential wildfire mitigation programs and extreme weather-related catastrophic event response costs with other sources of funding.
3. Identify cost-reduction measures by integrating wildfire mitigation strategies into the existing General Rate Case process.
4. Equitable rate structures: Refine the elements of Net Energy Metering so that all customers share wildfire mitigation, public purpose programs and system costs.
5. Redistribute the Climate Credit to customers most impacted by increasing electricity costs.
6. Fund today's and future cost-shifting programs from non-ratepayer sources.
7. Ensure that programs benefitting all electric customers are supported by all customers, including customers of publicly-owned utilities.

This report also describes ways in which programs add to overall costs and explains the ratepayer impact of how new programs create and distribute new costs and benefits.

## Ratepayer-Funded Programs Have Delivered Benefits in California and Across the United States

California's pioneering investments in clean energy technology have had impacts around the world. Customers of investor-owned utilities are funding programs and tariffs that bring many benefits: electricity bills have been the vehicle to fund the incubation and commercialization of technologies, including photovoltaic solar and battery storage, as well as the means to integrate renewable energy through programs such as time of use rates enabled by investments in advanced metering infrastructure.

Historically, California's programs have supported every stage of technological development:

- **Innovation,** through programs like the Electric Program Investment Charge program (EPIC),
- **Pilots,** like a new program harnessing vehicle-to-grid technology to turn Oakland United School District's newly electrified school bus fleet into a virtual power plant, and
- **Deployment at scale,** such as competitively bid generation projects through the Renewables Portfolio Standard.

These investments continue today through innovation with next-generation smart meters, microgrid technology, smart homes, generation that is increasingly disaggregated, and mechanisms to procure new renewable generation technologies like offshore wind.

As we move through the Innovation, Pilot, and Deployment process, we need to constantly evaluate whether the programs are succeeding on their own terms and whether their benefits outweigh their costs. In addition, the CPUC needs to be constantly evaluating the opportunity costs of the decisions to fund one approach over another. This is especially true of well-established areas like energy efficiency.

For some of these investments, all utility customers are sharing the incremental cost of programs that provide higher-cost individual benefits to a select group of customers or to private industry. Socializing investments can provide substantial benefits, such as helping certain small companies enter the renewable energy industry, providing energy efficiency or distributed energy resources to a group of low-income households, or improving plumbing and ventilation in public schools. These programs can bring important benefits and can avoid certain other costs. However, unless there is a non-utility source of funding, the costs of these investments are divided among all customers, and bill savings for one customer necessarily increases costs for everyone else.

## The Nature of Electricity Necessitates Infrastructure Sized to Meet Highest Potential Demand

Unlike commodities such as water, natural gas or gasoline, electricity does not persist if it is not used or stored after it is generated.

Considerable efforts are being made to put excess grid energy to work: batteries use electricity for charging, pumped storage facilities use electricity to move water to generate electricity later, time of use rates encourage customers to shift their energy use to daytime when solar energy is plentiful, and electric vehicles and buildings are a growing source of demand.

Electricity generators are generally compensated through contractual commitments to purchase energy or tariffs, and some are further compensated for the guarantee that they will be ready to serve demand whenever needed. Likewise, the grid is built to efficiently share electricity generation but must also be sized to meet the highest potential demand. Accordingly, using less energy does not always result in cost savings. While guaranteed load reduction measures are increasingly valuable at times of high usage, at other times, more load can mean lower rates.

One key to future cost reduction is increased electricity consumption from buildings and transportation electrification and other new loads, combined with flexible load measures that are targeted, predictable and controllable for system needs. This can bring relief to all customers: when existing infrastructure is used more efficiently and the same fixed costs are spread across a greater volume of electricity provided, customers' total energy costs can be reduced, and climate change action can be achieved at least cost.

## Today's Electricity Rates Trajectory

As the CPUC has detailed in its annual rates report,[1] today's rate increases are not driven by prices of contracts for new renewable energy generation.

Broadly, ratepayer bills are rising because of: wildfire risk reduction surrounding utility infrastructure, inequitable rate structures, programs that require energy procurement that is not needed or is not competitively priced, and programs that provide bill reductions or discounts to one group of ratepayers, thus leaving other customers with a larger share of overall costs.

In 2024, ratepayers of the three largest electric utilities paid a collective $54 billion in rates for the cost of utility services and investments.[2] While the CPUC looks for every opportunity to distribute costs fairly, collecting revenue through rates is inherently regressive: low-income Californians pay a higher share of their income for utility bills than higher-income Californians.[3]

## Distributing Costs and Benefits Fairly Is Key to Affordability

The electric system is large and dynamic, and numerous programs distribute the costs and benefits of it differently – and so distributing costs and benefits fairly is essential to affordability.

In a variety of policy decisions, the CPUC seeks to distribute costs progressively and aid California families who most need help reducing their utility bills. The CPUC also seeks to measure programs using cost-effectiveness tools that are continuously vetted by stakeholders. However, rising costs

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[1] See the 2024 SB 695 Report or the 2024 Padilla report.

[2] This includes a $12 billion proxy estimate for CCA generation costs, and subtracts the impact of the climate credit.

[3] Severin Borenstein, Meredith Fowlie, and James Sallee "Paying for Electricity in California: How Residential Rate Design Impacts Equity and Electrification" (September 2022). Paying for Electricity in California.

for the system and operations as well as requirements and programs beyond core utility services are causing electricity rates to increase significantly in recent years.

Many of these programs have benefits as well. The question presented by Executive Order N-5-24 is whether costs can be reduced and whether costs and benefits are being distributed in ways most fair to all customers, and in ways that enable California to achieve its clean energy and electrification goals.

## The CPUC Has Taken Actions to Mitigate Rising Rates

As the CPUC has recognized in its annual SB 695 reports,[4] electricity rates for customers of California's electric IOUs have been projected to increase faster than inflation. As the economic regulator of the state's IOUs, the CPUC limits approvals to necessary costs and identifies cost saving measures wherever they can be found.

The CPUC's adopted monthly flat rate of $24.15 for those who can pay and $12 per month for low-income customers reflects a positive shift toward more equitable ratemaking practices and movement away from regressive cost collection. The flat rate requires all customers to pay the same amount for a portion of utility costs that do not vary with volume of usage and gives low-income households a discount. It is a more progressive method to allocate costs than per-unit charges. More CPUC actions designed to decrease bills for ratepayers as a whole with a focus on equity are described in the appendix.

## The Impact of Legacy Contracts

After California legislation required its IOUs to divest generation assets, long-term clean energy contracts have been essential to meeting reliability needs while supporting emerging clean energy technologies. Such contracts, however, can also lead to long-term costs for ratepayers, particularly when they create ongoing financial commitments like contractual obligations or tariffs that extend benefits to electricity generators over time.

One example of an ongoing cost is legacy renewable energy contracts signed more than a decade ago. Load serving entities are required to procure sufficient energy to serve their customers long before it is needed, which is essential for reliability and for hedging against market volatility. Legacy contracts thus deliver benefits, and also impact ratepayers: in 2024, ratepayers paid an estimated $1.2 billion more than they would pay today for RPS contracts signed between the years 2000 and 2016.[5]

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[4] See the 2024 SB 695 Report.

[5] This estimate includes all RPS contracts signed between 2000 and 2016. This includes Qualifying Facility Standard Offer, ReMAT, BioMAT, and BioRAM. BioMat and BioRAM incurred an estimated $25 million in above-market costs, and ReMAT cost ratepayers approximately $5.4 million.

The CPUC has required utilities to renegotiate lower, market-competitive prices for these contracts when they are up for renewal, but above-market contracts persist.

These legacy contracts, together with other legacy costs, also have the unintended effect of creating a cost-savings value stream for any customer who can independently procure or self-generate electricity and thus off-set higher volumetric charges for energy, while still using the grid. In doing so, these customers avoid legacy and other fixed costs, and necessarily shift costs to other customers.

### Many Investor-Owned Utility Programs are Mandated by State Laws

As stated in this report, most electricity programs could be funded through non-ratepayer funds. This would shift costs away from customers.

The Legislature can also take statutory action to repeal or significantly revise mandated electricity programs that result in ratepayer costs that are higher than necessary for safe, reliable, clean electricity.

## What is Cost Effectiveness, and How Does it Affect Rates?

When a utility program has costs, rates rise, since those costs are paid on ratepayer bills. Some programs also reduce costs that are borne by ratepayers, but unless these reductions fully offset the costs, ratepayers will experience a rate increase.  This section explains why.

### Every Utility Program Carries Operational and/or Fixed Costs

In California, as in nearly every state, Investor-Owned Utilities (IOUs) collect operational costs on a “cost of service” model: IOUs are permitted to collect all the costs of providing electricity service to customers. The IOUs’ operations are a straight pass-through of costs. Utilities do not earn a profit on these costs.

When IOUs invest in infrastructure – substations, transmission, distribution lines, metering infrastructure, and more – they earn a return on these investments, known as their “authorized rate of return,” or profit. The capital invested by the utility plus a rate of return are paid back over time by all customers.

Each year, the total amount of a utility’s operational costs and an amortized portion of capital investments is divided up among all customers of the utility and allocated for collection largely according to the amount of electricity used. An electrical bill may also include electricity generation costs charged by a non-utility load serving entity such as a Community Choice Aggregator or an Electric Service Provider.

Together, operational and capital costs include every single utility program. Again, under the structure of the Legislature, the CPUC, and the utilities, every program that the Legislature directs the CPUC to implement via the utilities is either an operational cost, a capital cost, or both, and is paid for by ratepayers. Figure 1 summarizes the 2024 revenue requirement for the three large electric IOUs.

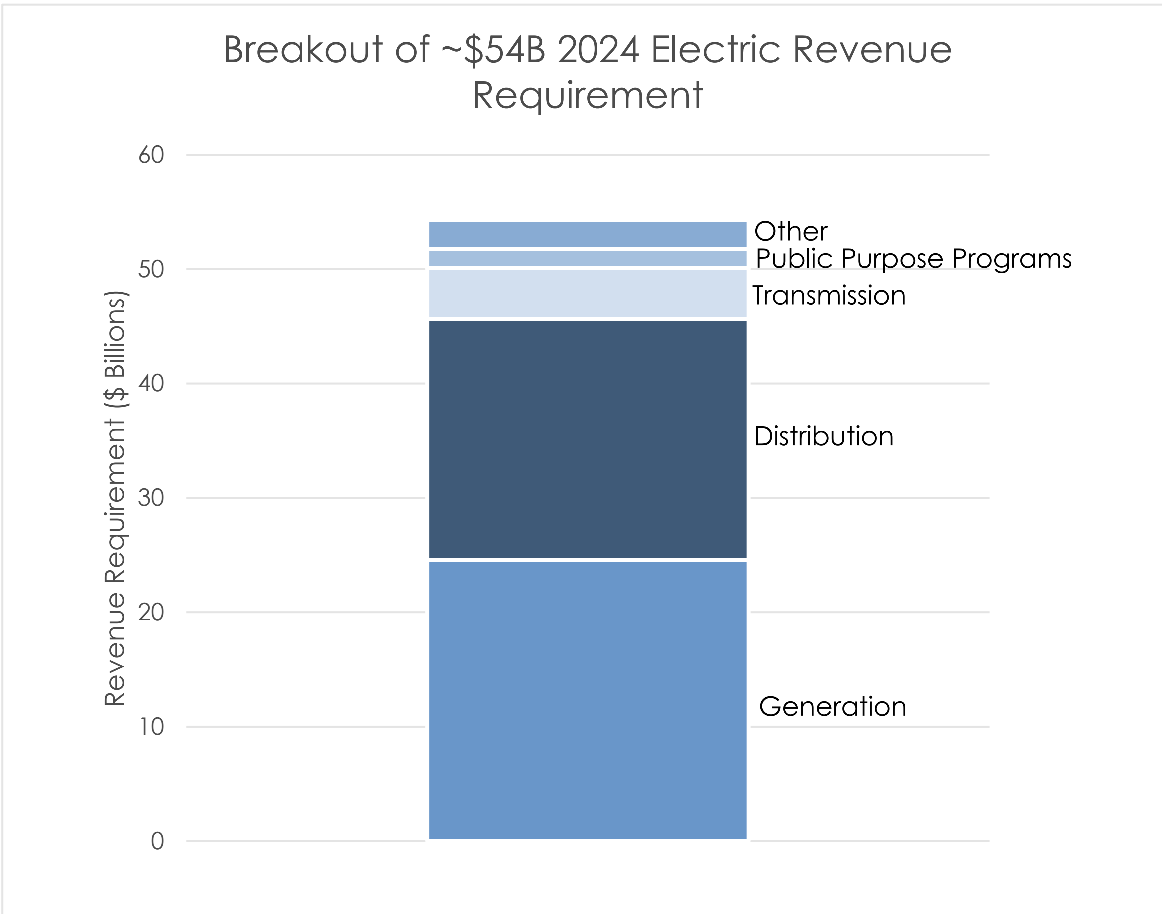


**Figure 1.** The combined 2024 electric revenue requirement for PG&E, SCE, and SDG&E, after subtracting the California Climate Credit. This estimate uses IOU generation costs as a proxy for Community Choice Aggregator generation costs. The majority of these costs must be paid to the utilities, regardless of electric sales. 2025's revenue requirement is projected to be approximately 5-9% higher than 2024's.

### The Capital Costs of the System Are Long-Term Investments That Support Numerous Goals

Capital costs include the physical infrastructure needed to deliver electricity to customers. Much of the recent increase in distribution and transmission costs are upgrades to improve system safety and reliability. This system must be built to meet peak system demand, and costs are not reduced if the system is used less at certain times of the day on certain days of the year. Long-term investments in the system make the system stronger, more resilient and better able to facilitate electrification of end uses, but they are also sunk costs that must be repaid, and therefore limit California's options to reduce rates.

### Under the Current Cost Allocation Structure, Some Customers Pay Less Operational and Fixed Costs While the Majority of Customers Pay More

Under the current cost allocation structure, some advantaged customers pay less than their share of operational and capital costs while disadvantaged customers pay more than their share of both, especially because more advantaged customers have benefitted from the NEM subsidies paid by all other customers. This is partially caused by a policy that eliminates the connection between the revenue an electric utility collects and the amount of energy they sell.

Observers often believe that utilities are seeking to sell more electricity to customers. This is an inaccurate viewpoint. Utilities are indifferent to how much electricity they sell to customers, because of an important energy policy that California adopted in the 1990s that breaks apart electricity sales from utility budgets. Numerous states have followed California's pathbreaking approach, and it has been foundational to the success of programs like energy efficiency and net energy metering. This "decoupled" approach means that if a utility sells more or less electricity in one year, any revenue over-collection or shortfall will either be returned to customers (in the case of over-collection) or collected (in the case of shortfall) the next year. Utilities' revenues are not linked to the amount of electricity they sell, so they have no incentive to sell more or less electricity to any group of customers or to ratepayers as a whole.

Because most operational and capital costs are fixed in advance and allocated on an annual basis, any program that provides rate relief for one customer group results in a shift of operational and fixed costs to another. The second group gets a rate increase, while the first group gets a rate or bill decrease. Figure 2 demonstrates the shifting of such costs from participants in such a program to non-participants. Electricity costs for the customers who don't receive the exemption can rise dramatically – an effect we are seeing today.

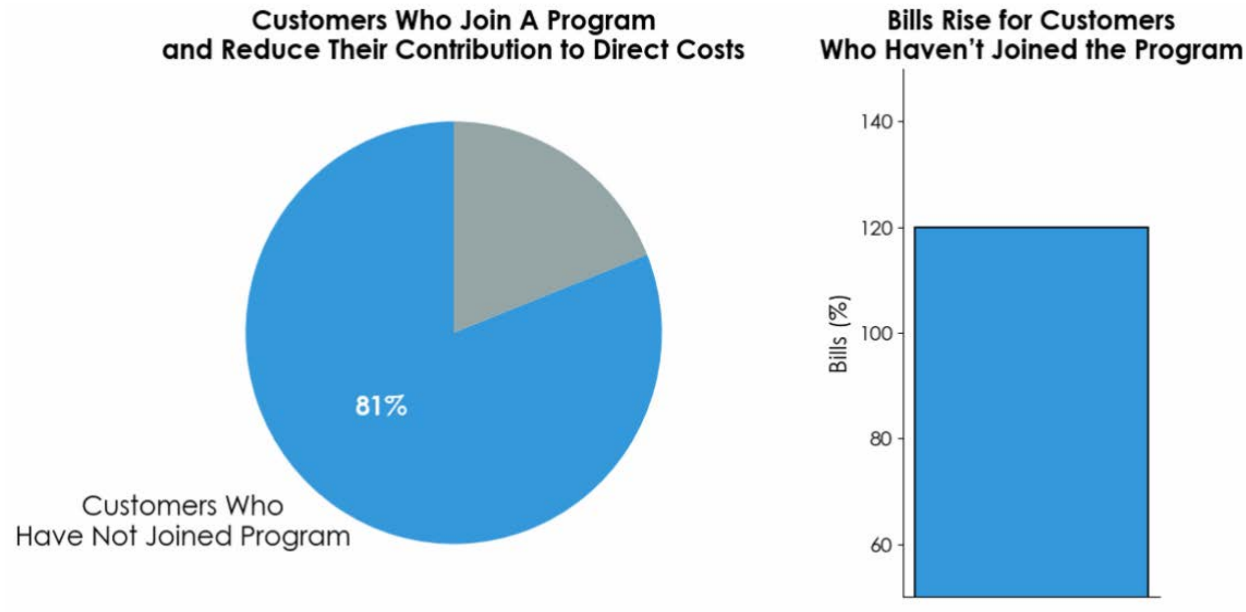


**Figure 2.** Animation showing the impact on customers who are not participating (blue) in a program, such as NEM 1 and 2, that allows other customers (grey) to reduce their contributions to direct costs. As fewer customers contribute to direct costs, the rest of customers pay higher rates to compensate. This figure is illustrative and does not reflect exact costs of any particular program. To view the animation, open this document in the desktop version Adobe, click on the graphic and "trust" the document.

This happens for a few reasons:

- In the short term, the cost of the entire physical electric system doesn't drop when less electricity is sold. As a result, allowing some customers to not pay for their share of fixed costs moves their share onto everyone else. Some programs may reduce costs in the long term, but only if they directly address the drivers of fixed costs.
- Numerous programs mandated by the Legislature require customers to pay for expensive electricity that would not be able to compete in market-based requests for offers. When utilities, CCAs, or Energy Service Providers are required to compensate generators for expensive electricity, such as for exports from rooftop solar under the Net Energy Metering Tariff, the customers who purchase less electricity overall are purchasing less of the expensive commodity, too. And in turn, the remaining customers who cannot reduce their electricity purchases are paying for a greater share of the more expensive electricity.

In general, the customers who are purchasing less electricity are those who own their homes and can afford to buy or lease rooftop solar panels and in-home battery storage. On that basis, we know that advantaged customers are paying less fixed and operational costs while disadvantaged customers are paying more.

## Net Energy Metering

Net Energy Metering (NEM) program costs are one of the largest contributors to rising electricity rates for customers that do not have rooftop solar. According to the Public Advocates Office, the NEM program's and the Net Billing Tariff's (NBT) combined $8.5 billion cost shift constitutes 21-27% of the average non-participating customer's bill.

The NEM 1.0 and NEM 2.0 programs increase electricity bills in two ways: (1) customers pay for the generation that is exported to the grid from another customer's NEM system at a higher rate than other available generation, and (2) customers pay for the part of bill savings experienced by NEM customers because the program allows rooftop customers to bypass their share of direct costs to maintain the electric grid, which other customers without rooftop solar end up paying (see figure 2, above).

IOU customers without rooftop solar are paying NEM customers for the generation they send to the electric grid at a rate that exceeds the cost of generation otherwise available from the grid. NEM 1.0 and NEM 2.0 customers are compensated for electricity exported to the grid at the retail volumetric rate, which exceeds the marginal cost of avoided wholesale generation purchased for that customer. IOU customers without rooftop solar pay this increased cost to NEM customers for 20 years after their grid interconnection dates.

Distributed energy resources, including batteries, electric vehicles, and heat pumps, are a part of California's overall electricity future, and new policies are helping to send improved price signals to these resources so that they can best support electric grid needs. From April 2023 on, new rooftop solar customers—will receive compensation through the new Net Billing Tariff (NBT), which provides compensation that is more aligned with the value of the generation the systems provide to other customers. It also includes more generous subsidies for systems with battery storage compared to rooftop solar. This cost increase, however, is not fully mitigated by the new Net Billing Tariff (NBT): NEM 2 customers who switch to the NBT can create a cost shift that is 76-82% as high as their cost shift under NEM 2.

## Cost Effectiveness Approaches

Cost effectiveness is a heavily contested concept. Two approaches have the most direct relevance to rates:[6] the Ratepayer Impact Measure, which identifies the extent to which savings for one customer shifts costs to another, and the Total Resource Cost test, which measures financial costs and benefits to all ratepayers and the utility. Both tests measure exclusively monetary costs, and do not

[6] There are two additional tests described in the CPUC's Standard Practice Manual: the Participant Cost Test, which measures whether a program is financially beneficial to participants, and the Program Administrator Test, which measures costs and benefits to the utility or entity administering the program. The Societal Cost Test measures costs and benefits to society and was recently adopted to use on an informational basis by the CPUC in D.24-07-015.

include non-monetary benefits and costs such as the societal cost of carbon and health or safety benefits.

Generally, when a program's financial benefits to ratepayers outweigh its costs, it will have a Total Resource Cost effectiveness score over 1.0 and it will lower total system costs relative to other resources. Conversely, a score below 1 indicates that a program will raise total system costs relative to the alternative. A score below 1.0 on the Ratepayer Impact Measure indicates that the program raises rates by creating more costs for non-participating customer than it saves for the grid as a whole.

In the time available to prepare this report, the CPUC has not carried out a comprehensive cost effectiveness review of all programs under its purview. In many cases, the statute directing the CPUC to establish the program does not require that the program be cost effective. When the CPUC examines cost effectiveness of an electricity program, it is typically conducted within CPUC proceedings, during which dozens of stakeholders litigate the analysis and results.

# Section 1 - Response to Executive Order Request to Review Programs

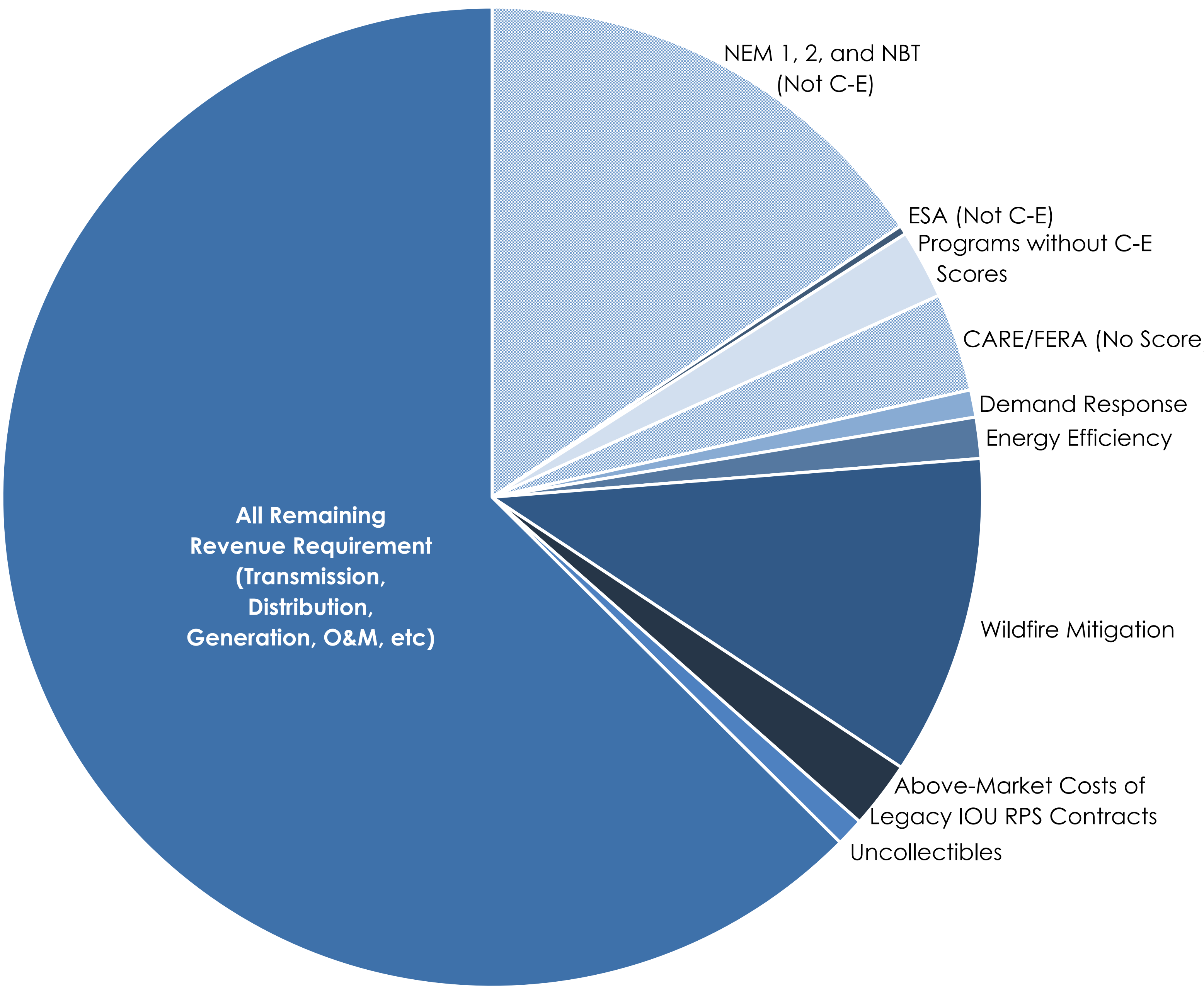


**Figure 3** shows the contribution to rates of programs funded through electric IOU revenues. Note that this figure conflates the cost shifting (indicated by textured wedges) visualized in Figure 2 with direct costs like the expense of purchasing energy from biomass incinerators in the BioMAT and

BioRAM programs. The chart is best understood to show the potential impacts on IOU electric revenue collections (and therefore system average rates) if programs were funded outside of electric rates. Eliminating programs whose primary rate impact is through cost shifting would affect which customers pay certain costs, but would have virtually no direct impact on average bills. For example, repealing and eliminating California Alternate Rates for Energy (CARE) would dramatically increase costs for the most vulnerable ratepayers and lower costs for wealthier ratepayers, commercial customers, and industrial customers.[7] It would not impact average bills because savings for one group translate directly into costs for another.

Because each customer class (residential, commercial, industrial) contributes different amounts to each program and cost shift, class-specific impacts would vary from the amount shown in the pie chart. For example, Net Energy Metering and the Net Billing Tariff primarily shift costs within the residential class: funding the cost shift from an outside source would create significantly greater than 15.6% savings for non-participating residential customers.

A full list of programs with their approximate annual costs can be found in the Appendix.

## What All of This Means: Opportunities to Cut Rates Today and For the Future

There are opportunities to cut rates today, which will promote affordability. Finding ways to save ratepayers money is essential. The CPUC's analysis shows the following:

1. For context, in 2024 electric ratepayers will pay approximately $54 billion in rates to the three large IOUs and to community choice aggregators. In 2025, revenue requirements are projected to increase an estimated 5-9%.[8]
2. From 2019 to 2024, the IOUs collected approximately $24 billion in wildfire mitigation and insurance premium costs.[9]
3. While the vast majority of industrial, commercial, and residential customers do not have solar panels, the California Public Advocates Office estimates that they will pay approximately $8.5 billion in 2024 for the 15% of customers who do, under the NEM 1,

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[7] Approximately three quarters of the CARE subsidy is paid for by non-residential customers. If there were no CARE program, average rates within the residential class would rise: CARE customers would pay approximately $1.9 billion more, while non-CARE residential customers would only save approximately $500 million.

[8] This estimate uses IOU generation costs as a proxy for CCA generation costs, and subtracts the impact of the California Climate Credit. The overall increase in revenue requirement depends on the result of pending proceedings.

[9] Approximately $18 billion was placed into revenue requirements through 2023. See 2024 SB 695 Report, p. 53. At the time of this report's drafting, 2024 costs were estimated to be approximately $6 Billion.

NEM 2, and NBT tariff programs. The Public Advocates office estimates that this cost shift represents 21-27% of residential bills.[10]

4. The flagship low-income discount programs, California Alternate Rates for Energy (CARE) and Family Electric Rates for Energy (FERA) shift approximately $1.75 Billion to non-participating customers. Nearly three quarters of these costs are paid by non-residential customers.
5. The remaining electricity programs that the CPUC orders the IOUs to carry out based on mandates from the Legislature total approximately $2 to $2.5 billion per year. Half of this amount is spent on programs demonstrated to be cost-effective. The remaining half is spent on programs that have benefits and costs, but have not been reviewed for cost-effectiveness.

Based on the above facts, the following are potential principles for consideration. These require statutory changes, budget from another source, or other methods of implementation:

1. **Fund the NEM and NBT Cost Shift From Non-Ratepayer Sources:** Achieve a rate drop in 2025 of approximately 15.6% systemwide[11] by funding $8.5 billion for NEM 1, NEM 2, and NBT customers from non-ratepayer sources. Sustain the rate drop through a commitment to steadily increase the allocation as the number of NBT customers, and the associated cost shift, grows.[12]
2. **Reduce the NEM and NBT Cost Shift:** the cost shift created by NEM 1, 2, and the NBT could be reduced by:
   a. **Shorten legacy periods:** almost all NEM 1 and 2 customers have more than 10 years before they will be defaulted onto the NBT. Nearly half have 15 or more years of this legacy period remaining. By reducing the legacy period from 20 years, NEM 1 and 2 customers could be defaulted onto the Net Billing Tariff sooner. This would save non-participants billions of dollars.
   b. **Tie compensation for excess generation from solar systems to rates in effect when NEM customers interconnected:** Because NEM customers receive retail rates for any excess electricity that passes through their meter, the amount paid by non-NEM customers for this excess energy is increasing over time as rates rise. Tying compensation for excess generation to the rates in effect when a NEM or NBT customer signed up for the tariff would mitigate the increase in cost shifts.
   **c. Establish a Grid Benefits Charge for NEM and NBT customers:** Solar customers use the grid to import and export energy, but a large portion of their

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[10] Per the Public Advocates Office. [240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet].

[11] Per the Public Advocates Office, the NEM 1, 2, and NBT cost shift totals $8.5 billion in 2024. [240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet].

[12] While the NBT is an improvement over NEM 1 and 2, it does not eliminate the cost shift. NEM 1 and 2 customers have a 20-year legacy period, and the majority connected within the last 5 years. If volumetric electric rates continue to increase, the cost shift from these customers will continue to grow.

existing share of system costs is necessarily moved to other customers' bills when their systems are installed. A monthly charge for NEM and NBT customers would help to reduce the amount that shifts from NEM customer bills to non-NEM customer bills.

   d. **Tying legacy periods to the customer, not the system:** currently, the 20-year legacy period before which NEM 1 and 2 customers are defaulted onto the NBT is linked to the installed system, not the customer. Systems could be converted to the NBT when the home changes ownership or at the end of the legacy period, whichever is sooner, rather than only when the system reaches the end of its legacy period.

3. **Use Stable Non-Ratepayer Funds to Increase the CARE and FERA Discount:** Because fixed costs are high and will remain so for the foreseeable future, a stable source of non-ratepayer funding can be used for a larger direct subsidy to low-income Californians on their electricity bills.
4. **Fund Other Programs From a Non-Ratepayer Source:** Achieve a rate drop of up to approximately 2.3% starting in 2027 through statutory changes in 2025 that fund programs without cost-effectiveness scores from non-ratepayer sources. These programs also provide benefits - repealing them entirely would produce ongoing savings significantly lower than 2.3%, by also eliminating any benefits they provide.
5. **Fund Any Future Cost-Shifting Programs from Non-Ratepayer Sources:** Future programs that give exemptions to certain customer groups should be allocated funding from non-ratepayer sources so that other customer groups do not pay for them.
6. **Use Existing Review Processes of Utility Spending:** The existing General Rate Case (GRC) process is often the best way to ensure that all costs are reasonable and cost-effective, particularly in wildfire-related areas. New programmatic mandates should be evaluated through the GRC instead of standalone applications, such as those to collect costs tracked in memorandum accounts.
7. **If a Program Benefits all Electric Customers, All Electric Customers Should Contribute:** Any program funded by electric ratepayers for the benefit of all of California should be paid for by all electric customers, including the customers of publicly owned utilities.
8. **Prioritize the Needs of Ratepayers:** All energy-related mandates should be assessed for overall cost-effectiveness with the goal of achieving lowest possible rates for all customers of each utility. In addition, statutes ordering the CPUC to prioritize a specific industry's needs, the needs of a specific customer group, or other needs beyond the delivery of safe, reliable and clean energy[13] over the needs of all ratepayers are likely to increase costs.

[13] For example, SB 1090 requires ratepayers to reimburse $85 million in lost local government tax revenue due to the closure of Diablo Canyon Nuclear Plant and pay $128 million in employee retention funding beyond what the CPUC approved. These priorities contribute to increases in PG&E customer bills.

## Actions to Be Taken Under the CPUC's Authority

The following are examples of actions the CPUC could take to reduce ratepayer costs:

1. **Open an Energy Efficiency Rulemaking**: The CPUC plans to open a new rulemaking on energy efficiency in 2025. It will include a focus on cost effectiveness.
2. **Move toward incorporating a greater share of ratepayer costs into General Rate Cases for holistic review and decision-making.**
3. **Evaluate new programs for cost-effectiveness** where appropriate. Identify statutory barriers to implementing cost effectiveness tests on mandated programs.
4. **Improve risk-informed spending** by continuing efforts in the Risk-Based Decisionmaking Framework proceeding, directing the utilities to provide better and more consistent information about how they incorporate risk into their GRC funding requests.
5. **Consider reprioritizing transportation electrification spending by focusing on critical grid investments and pausing $1 billion in new ratepayer charges** previously authorized in the Transportation Electrification Framework decision.
6. **Approve lower-cost wildfire risk mitigation methods** where appropriate.
7. **Identify programs meeting the following criteria:**
    a. Programs that require ratepayers to purchase energy from specific generation types that are not competitive with alternative RPS-eligible resources.[14] Removal of costs from rates may require legislative action.
    b. Programs that are underutilitized and could return funds to ratepayers.
8. **Continually improve the efficiency of the CPUC's administrative processes.**

[14] Above-market mandated procurement can occur through tariffs or non-competitively bid contracts.

# Section 2 – Response to Executive Order Request to Consider Ways to Improve the Effectiveness of the California Climate Credit

The California Climate Credit is a twice-per-year bill credit automatically provided to all residential and certain qualifying small businesses. Qualifying energy intensive trade-exposed ("EITE") industrial customers also receive the California Industry Assistance credit. The funds originate from the California Cap-and-Trade Program, which requires power plants, fuel providers, and large industrial facilities that emit greenhouse gases to turn in for compliance carbon pollution allowances equal to their greenhouse gas emissions.

The credit is designed to help utility customers during the transition to a low-carbon future by sharing proceeds from the sale of allowances with customers. In 2025, the residential climate credit will total $1.39 billion (an average of $120 per customer), with another $117 million for small businesses and $104 million for EITE industrial customers.

As noted in this report, the burden of high rates does not affect all customers evenly. Pursuant to Executive Order N-5-24, this section explores several potential approaches to maximize the effectiveness of these funds.

The minimal administrative cost is a particular strength of the identified approaches.

## Allocating the Climate Credit to Specific Customer Groups

Currently, every residential customer receives a credit on their bill twice per year as their share of the proceeds from California's cap and trade program. In 2025, more than 11.6 million customer accounts will receive an average of $120.

The Climate Credit presents a significant equity opportunity for California. The Climate Credit could be reallocated to customers who need it the most: first, to all customers who receive the CARE benefit, and second, all customers without rooftop solar who are paying for those who have it.

The potential bill credits under three possible alternative approaches are outlined in the table below: allocating the climate credit exclusively to CARE customer accounts, and allocating it to all non-

NEM 1.0, 2.0, and Net Billing Tariff accounts, and allocating it to non-NEM/NBT CARE and FERA customers, along with non-NEM/NBT customers in the hottest climate zones.

Additionally, funding from other sources could be added to the climate credit, increasing the customer benefits shown below.

| Allocation | Total Residential Climate Credit, 2025 | Estimated Total Benefiting Accounts | Resulting Bill Credit |
|---|---|---|---|
| **All Customer Accounts (status quo)** | $1.39 Billion | 11.6 million | $120 |
| **CARE and FERA Customer Accounts only** | $1.39 Billion | 3.1 million | $454 |
| **Non-NEM 1.0, 2.0, or NBT Customer Accounts** | $1.39 Billion | 9.9 million | $142 |
| **Non-NEM/NBT CARE, FERA, and Customers in Hottest Climate Zones** | | | $445[15] |

[15] "Reallocating the Residential California Climate Credit to Low-Income Customers." Dollar value may not be directly comparable to others in this table because the workpaper may have used different assumptions.

### Volumetric Distribution of Climate Credit

Currently, the Climate Credit is given twice per year in a lump sum. It could be allocated on the basis of usage, reducing the volumetric rate for electricity. While this would not reduce total annual bills, it could potentially make electrification more appealing to ratepayers. It would also reduce month-to-month bill volatility, easing ups and downs of utility bills for many Californians. Any change from a non-volumetric to volumetric return of the climate credit must be reflected in the Cap-and-Trade Regulation.

| Rate Reduction if $1.4B Residential Credit were Allocated Volumetrically |
|---|
| $0.023/kWh |

# Section 3 - Response to Executive Order Request to Recommend Ways to Reduce Wildfire Mitigation Costs

*This section is the joint response of the Office of Energy Infrastructure Safety and the CPUC in accordance with Paragraph 5 of Executive Oder N-5-24.*

## Background

Wildfire represents the single most significant financial and safety risk for California's investor-owned electrical utilities. California is experiencing compounding impacts of climate change, as wildfires become larger, more intense, and harder to contain than ever before. Because wildfire represents such a considerable risk, utilities are required to prepare Wildfire Mitigation Plans (WMPs) describing their strategies for reducing wildfire risk for review and approval by the Office of Energy Infrastructure Safety (Energy Safety). As noted above, between 2019 and 2024, IOUs collected approximately $24 billion from ratepayers to pay for wildfire mitigation costs and insurance premiums.[16]

The WMPs have dramatically improved the way electrical utilities in California understand and reduce the risk of utility-caused wildfire. However, the cost of implementing these plans has resulted in associated wildfire mitigation-related rate pressures.

### Wildfire Risk Mitigation Will Continue to Contribute to Electricity Rate Increases

Ignition risk associated with electric lines can be reduced through a variety of approaches including vegetation management, grid hardening, replacing uninsulated lines with covered conductors, and undergrounding.

- Undergrounding: moving above-ground lines beneath the surface.

[16] Approximately $18 billion was collected through 2023. See 2024 SB 695 Report, p. 53. At the time of this report's drafting, 2024 costs were estimated to be approximately $6 Billion.

- Covered Conductor: replacing wires with heavily insulated alternatives that are far less likely to spark than traditional wires.
- Other Grid Hardening and Grid Design: can include replacing wooden poles with fire-resistant materials, replacement or strengthening of infrastructure, segmentation of lines to allow isolation of faults, or adding sensors to cut power when electric faults are detected.
- Vegetation Management: Removing and trimming trees and other vegetation around electrical lines and equipment to reduce the risk of vegetation coming into contact with power lines and reducing the amount of dry vegetation close to electrical equipment.

While each approach reduces wildfire risk to varying degrees, undergrounding raises rates the most and takes the longest to implement. Although undergrounding costs are hard to estimate and vary dramatically because of many factors, including topography, estimates show that undergrounding every IOU distribution line in high fire threat areas could cost an estimated $92-224 billion. Undergrounding transmission would be significantly more costly. In contrast, installing covered conductor would cost approximately one-fourth as much.[17]

Of the four approaches, undergrounding is in certain locations the most effective option, and is therefore an essential tool in utility efforts to reduce wildfire risk. SB 884 facilitates longer-term utility infrastructure undergrounding investments, but does not provide a source of funding for this work other than increases in customer bills.

No matter the approach, the costs associated with hardening the electric grid to reduce the risk of utility-ignited wildfires are borne by ratepayers through increases in electricity rates. The most effective way to reduce the electricity bill impact is to fund these investments from a source other than ratepayers.

## Consolidating and Streamlining Utility Funding Requests Will Provide Some Relief

These rate pressures may be reduced through increased transparency and improved coordination of cost approval processes, electric underground infrastructure construction, and fuel treatment efforts.

Currently, electrical utilities request wildfire mitigation funding through multiple mechanisms at the CPUC, including GRCs, memorandum accounts for the recovery of WMP costs, and, prospectively, additional applications for large electrical undergrounding plans. The multiple streams of funding for

[17] Depending on the IOU, undergrounding distribution lines costs $2.3-$5.6 million per mile, while transmission undergrounding is significantly more expensive: the Tehachapi Renewable Transmission Project cost $139 million (in 2025 dollars) per mile to underground. Covered conductor costs $770,000 - $1.35 million per mile. There are approximately 40,000 miles of above-ground IOU distribution lines in California's High Fire Threat Districts. Per-mile costs are drawn from recent IOU filings and CPUC decisions. This calculation is highly uncertain.

wildfire mitigation decrease transparency, complicate oversight, and reduce accountability, leading to increased rates.

The CPUC's GRC process is the most transparent available process and requires the highest levels of cost justification. The GRC allows parties to the proceeding to scrutinize proposed spending forecasts and present evidence in support of lower or higher amounts than those proposed by the electrical utilities. Based on the evidence presented, the CPUC ultimately prospectively approves a fixed amount of funding utilities may recover from ratepayers each year of the four-year GRC cycle. In the case of costs required to implement WMPs, the CPUC is required to allow the utilities to track and record additional costs, above approved GRC forecasts, and seek cost recovery from ratepayers for these expenditures.

## Solutions Requiring Legislation

### Integrating Wildfire Mitigation Plans into Utility General Rate Cases

The implementation measures included in Wildfire Mitigation Plans (WMPs) are not currently subject to the coordinated cost review and evaluation that other utility programs and investments receive. This may unnecessarily drive costs up and decrease transparency of wildfire-related spending. Applications to recover many of these costs are often filed after the work is completed and involve lengthy, contentious proceedings to evaluate potential overlap with GRC approvals and after-the-fact reasonableness of expenditures. The time delay increases debt carrying costs that must be paid by ratepayers.

The Public Utilities Code could be amended to require utilities to integrate WMP costs into the normal planning and budgeting process (their GRC) instead of treating it as a stand-alone activity. While the CPUC could still authorize utilities to track and recover WMP implementation costs that exceed GRC-authorized amounts, utilities would need to include their entire forecasted amounts in GRC applications. This modification would reduce ratepayer costs by allowing CPUC review of planned expenditures before work is completed and help ensure that utilities choose the most cost-effective mitigations.

The aim of the alignment would be to increase administrative efficiency by reducing the rate at which utilities prepare comprehensive wildfire mitigation plans from once every three years to once every four years. While the WMP process to date has successfully driven electrical utilities to rapidly improve how they understand and address wildfire risk, utilities have matured to the point where they can be expected to incorporate their wildfire mitigation planning into the GRC process. Synchronizing WMP planning with planning for other spending, along with additional procedural changes, would improve clarity and reduce redundancy in the Energy Safety and CPUC review processes. The elimination of more than a dozen CPUC resolutions ratifying WMPs every year would lead to significant reductions in planning, preparation, review, and litigation expenses for the CPUC, Energy Safety, and utilities.

Finally, this proposal would improve utilities' certainty as to what wildfire mitigation activities must be completed as well as the associated approved budgets thereby avoiding complex factual determinations around the reasonableness of utility incremental spending over GRC approvals.

These changes would largely mirror those proposed in SB 1003 (Dodd, as amended August 28) during the 2023-2024 legislative session. Energy Safety would continue to review and approve or deny WMPs while the revenue approval remains with the CPUC.

This alignment would build on lessons learned from the past five years and prepare California for the next phase of utility wildfire risk reduction. It would also preserve successful features of the current oversight model:

- The reforms keep the focus on mitigating utility wildfire risk. Energy Safety will continue to set requirements and evaluate the quality of WMPs.
- Every year, Energy Safety would assess utility implementation of WMPs and provide feedback to utilities and CPUC.
- Every year, utilities would continue to apply for certification from Energy Safety based on enumerated statutory criteria rooted in proactive investments in safety. By meeting these criteria, the utilities demonstrate their commitment to safety culture, safety based executive compensation, transparent reporting, and continued maturity in their planning efforts. In return, they can be entitled to a presumption of reasonable action in a proceeding before the CPUC to recover costs in the event of a utility related wildfire.
- The CPUC would evaluate and approve wildfire spending costs with attention to cost effectiveness.
- The CPUC would still have authority penalize utilities who do not implement their WMPs.

## Reducing the Construction Costs of Burying Electric Utilities

When undergrounding their facilities, electrical utilities do not consistently receive information on the location of other utilities' underground infrastructure until two days before excavation begins. Therefore, contractors installing electric infrastructure are often required to make costly changes during construction to account for previously unknown existing underground facilities, driving up the cost of constructing new underground facilities.

These challenges could be addressed by legislation authorizing Energy Safety's Underground Safety Board to determine how utilities must provide buried facility records to electrical and other utilities during the project planning and design phases. This would be accomplished through processes used by existing 811 underground service alert notification centers. Energy Safety's Underground Safety

Board would need the authority to develop regulations requiring contractors who submit a significant number of 811 tickets to provide advance notice to utility operators in the affected area. This advance notice, which could be integrated into the 811 design process, would enable utility operators to more effectively plan for large-scale projects.  This process could also be used to facilitate early Tribal notification of pending excavation activities.

## Solutions Actionable on Existing Authority

### Energy Safety: Better Fuels Treatment Coordination Between Electrical Utilities and Large Landowners

Electrical utilities generally plan wildfire mitigation activities independently of the extensive coordinated wildfire mitigation work occurring throughout the state. WMP initiatives activities can be costly to plan and implement as stand-alone small-scale projects and are often too limited in scale to protect electric companies' assets from wildland fires. Energy Safety could leverage its existing participation in various wildfire mitigation boards and task forces, along with its relationships with the electrical utilities, to facilitate broader coordination and integrated wildfire mitigation projects between public and private partners.

Coordination of fuel management treatment design, permitting, and environmental review work produces savings for land managers and electrical utilities. Stewardship agreements could allow multiple entities to hire a single contractor to conduct the forest fuel reduction treatments across a broader geographical area.

As an example, the 6,400-acre Liberty Utilities Resilience Corridors Project—coordinated with the U. S. Forest Service— enabled fuel reduction treatment along utility corridors and allowed the Forest Service and Liberty Utilities to share in the costs. Energy Safety can work with existing partners such as the Office of the State Fire Marshal and the California and the Wildfire and Forest Resilience Task Force to identify and facilitate similar projects.

# Section 4 – Response to Executive Order Request to Pursue Federal Funding Opportunities

In April 2024, the Commission adopted Resolution E-5254. The Resolution formalized support for IOU pursuit of federal funding opportunities, allowed for the establishment of a memorandum account to track spending on applications and other federal funding costs, and established a process for utilities to seek cost recovery for any required ratepayer cost shares for successful grant applications. Utilities are directed to apply for cost recovery through the existing general rate case (GRC) or application process to ensure that all projects face a sufficient level of scrutiny and opportunity for public engagement.

The utilities have also received multiple letters from CPUC President Alice Reynolds directing them to pursue all available funding opportunities, highlighting upcoming deadlines, and ordering the IOUs to report on their efforts to apply for funding.

These efforts have led to significant successes, including a $15 billion low-interest loan from the Department of Energy. Additional funding is summarized in table A-3 of this report's appendix. The CPUC will continue to strongly support and encourage the IOUs to secure any and all available non-ratepayer funding.

# Appendix

## CPUC Actions Taken to Reduce Costs

**Wildfire Self-Insurance Produces Ratepayer Savings**

- Cost of commercial market wildfire insurance has escalated in recent years.
- The CPUC approved proposals for PG&E and SCE to implement wildfire self-insurance, estimated to have resulted in a $467 million ratepayer savings impact in 2023.[18]

Similar savings are anticipated for future years.

**Equity Rate Base Exclusion and Optional Securitization Limit Rate Increases**

- As directed by AB 1054, the annual revenue requirements approved by the CPUC preclude the IOUs from recovering a Return on Equity on $5 billion in wildfire mitigation capital costs.[19]
- These equity rate base exclusions are forecasted to save ratepayers as much as $2 billion over the lifetime of the assets.
- AB 1054 also allows for securitization of wildfire mitigation capital spending. Securitization benefits ratepayers by allowing the securitized bonds to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures.[20]

As of July 2024, the CPUC has authorized $10.9 billion in securitization bonds under AB 1054 and SB 901.[21]

**Net Billing Tariff (NBT) Limits Cost Increases**

- The CPUC reduced electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems in the future.[22]
- While Net Energy Metering (NEM) 1.0 and 2.0 programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers. The NBT decision does not change the ongoing increased costs that non-participating customers pay for participants to remain on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future

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[18] *See* D.23-01-005 issued in PG&E's 2023 General Rate Case (A.21-06-021) and D.23-05-013 issued in SCE's 2021 General Rate Case (A.19-08-013).
[19] AB 1054 excludes the first $5 billion of the large IOUs' Wildfire Mitigation Plan (WMP) capital spending from earning a return on equity. (AB 1054, Section 18). This limits rate increases directly by eliminating the investor return portion of the return on rate base of $5 billion in WMP capital spending. *See* Chapter IV, Wildfire-Related Costs section for each IOU's total equity rate base exclusion amount.
[20] *See* Chapter IV, Wildfire-Related Costs section for specific Financing Order Application and Decision numbers.
[21] Under PG&E's bankruptcy plan and SB 901, the CPUC also authorized $7.5 billion in securitization (SB 901, Section 32).
[22] *See* D.22-12-056 in proceeding R. 20-08-020.

| |
|---|
| cost shifts: the NBT reduces the per-customer cost shift by an estimated 18-24% relative to NEM 2.[23] |
| **Virtual Net Billing Tariff (VNBT) and NBT Aggregation Subtariff Limit Cost Increases**<br>• The CPUC reduced electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems using the VNBT and NBT Aggregation programs compared to previous Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEMA) programs.[24]<br>• While VNEM and NEMA programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers. The decision does not change the ongoing cost shift created by customers remaining on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future bill increases that occur when other customers install rooftop solar and solar-plus-storage systems using the new tariffs. |
| **Self-Generation Incentive Program Transitioned to Non-Ratepayer Funding Source**<br>• Pursuant to AB 209, the CPUC allocated $280 million from the Greenhouse Gas Reduction Fund to the Self-Generation Incentive Program (SGIP) Residential Solar and Storage Equity budget.<br>• This allowed the program to continue to support resiliency in low-income and environmental and social justice communities without drawing on ratepayer funds. |
| **Intervention In Federal Transmission Owner Rate Cases Saves Ratepayers Money**<br>• The CPUC continuously advocates in Transmission Owner rate cases at FERC on behalf of ratepayers.<br>• Ratepayer savings are ongoing and estimated to be $5 billion since 2018, or $700 million per year. |
| **Transmission Project Review (TPR) Process Increases Transparency of Costs**<br>• CPUC designed the TPR Process to provide cost transparency of IOUs' transmission projects before Federal Energy Regulatory Commission whose costs exceed $1 million.[25]<br>• While not always quantifiable, savings from previous FERC-derived processes between 2020 and 2023 resulted in quantified long-term savings to ratepayers of between $500 million and $1 billion.<br>• As the TPR Process is more robust than those earlier processes, the affordability benefits to ratepayers are expected to be at least as great. |
| **Implementation of FERC Order Saves Ratepayers Money** |

[23] Comparing a NEM 2 solar-only customer to an NBT solar and storage customer.

[24] *See* D.23-11-068 in proceeding R.20-08-020.

[25] The TPR Process was established in Resolution E-5252.

- AB 209 reaffirms and clarifies that IOU participation in the CAISO is ordered by the CPUC and not voluntary. This clarification confirms that the IOUs cannot collect additional costs from ratepayers as an incentive to participate in an ISO.
- The Federal Energy Regulatory Commission (FERC) ruled in December 2023 that AB 209 is clear that incentives are not appropriate if an action is already mandatory. This adder will not be allowed in future rate cases and has an estimated cost savings of $86 million in 2024.

**The GRC Process is Transparent and Publicly Vetted**

- The CPUC's GRC proceedings require a transparent process for analyzing proposed utility costs and high levels of cost justification.
- In GRC proceedings, the CPUC requires evidence of forecasted costs and uses procedures for parties to litigate these forecasts in a public proceeding. **This process enables the commission to identify necessary and cost-effective expenditures and typically leads to approvals that are lower than utility cost recovery requests.**

**Revision of Electric Rule 20 Prevents Ratepayers From Funding Inequitable Investments**

- The Rule 20A program subsidized the undergrounding of power lines for aesthetic purposes in localized areas and benefits few ratepayers at the expense of the many ratepayers.
- The CPUC discontinued and is phasing down the Rule 20A Program by 2033 to prevent ratepayers from funding inactive and inequitable infrastructure investments.[26]
- The action is estimated to save $74 million annually through 2033.

[26] *See* D.23-06-008 in proceeding R.17-05-010.

Table A-2. Program list.

| | Bill or Statute Mandating Program, if Any | Ratepayer Funding ($ Millions, unless otherwise noted) | % Reduction in Average Rates if Funded by Non-Ratepayer Funds | One-Time Savings if Discontinued | Cost Effective? Blank Cells Mean No Evaluation Has Been Conducted |
|---|---|---|---|---|---|
| NEM 1 and 2 | PU Code Sections 2827 and 2827.1 | $8.25 Billion in Cost Shifts[21] | 15.2% | | No |
| CARE and FERA | PU Code Section 739.1 | $1.75 Billion (1/3rd from residential customers) | 3.2% | | |
| Energy Efficiency | PU Code 454.55, 454.56 | $810 | 1.5% | | Yes, with non-cost-effective components |
| Demand Response | PU Code Sections 454.5(b)(9)(C)(i), 380, 400(c), 769 | $486 | 0.9% | | Yes, with pilots excluded from cost-effectiveness requirements |
| Uncollectibles/Arrearage Management Program (AMP) | | $483 million in 2025, $204 million from AMP | 0.9% | | |
| CalSHAPE (AB 841) | PU Code Sections 1610-1618, 1620-1627, 1630-1633 | $331 | 0.60% | | |

| | | | | | |
|---|---|---|---|---|---|
| Net Billing Tariff | PU Code Sections 2827 and 2827.1 | $250 million in cost shifts[27] | 0.4% | | No |
| Energy Savings Assistance (ESA) | PU Code Section 382 | ~$140-200 million | 0.3% | | No |
| Transportation Electrification Rebate Program | | $200 | 0.40% | | |
| EPIC | | $185 | 0.3% | | |
| BioMAT/BioRA M | PU Code Section 399.20 | $150 | 0.3% | | |
| SOMAH | PU Code Section 2870) | $100 | 0.2% | $517 | |
| VNEM | | Approximately $26 million in 2022[28] | 0.04% | | No |
| RES-BCT | PU Code Section 2830 | ~$30-50 million in cost shifting | 0.05% | | |
| DAC-GT/CSGT | PU Code Section 2827.1 | $24 | 0.04% | | |
| SB 1090 – Diablo Canyon Settlement Agreement | PU Code 712.7 | $9.48 million in 2024, $213 million total, | | | |

[27] Per the Public Advocates Office. [240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet]().

[28] Decision 23-11-068, page 22.

| | | | | | |
|---|---|---|---|---|---|
| Microgrid Incentive Program | PU Code 8370, 8371 | Low millions in 2024, up to $200 million over 3-6 years | | | |
| RISE | | $0 in 2024, $50 million total | | $50 | |
| AB 841 (Transportation Electrification) | PU Code Sections 740.12, 740.18, 740.19, and 740.20. | Unknown – shifts costs to non-participating customers | | | |
| Fuel Cell Net Energy Metering (NEM-FC) | PU Code Section 2827.10 | Low millions in cost shifting from 120 MW of capacity – NEM 2 Lookback Study found small cost shift from commercial customers | | | |
| NEM-A | PU Code 2827, 2827.1 | Low millions in cost shifting | | | |
| Solar Equipment List | PU Code Section 2851 | $1.28 | 0.01% | | |
| Clean Energy Financing | | $0 | 0% | $270.5 | |
| SGIP | PU Code 379.6 | $0<br>Unquantified cost shifting | Unquantified | ~$129 million | |

| | | | | | |
|---|---|---|---|---|---|
| TECH | PU Code sections 922, 748.6 | $0 | 0% | | |
| Community Renewable Energy Program (CREP) | PU Code sections 769.3 and 913.15 | $0 | 0% | | |
| AB 2109 – Industrial Surcharge Exemption | PU Code Sections 371 and 451.7 | Unknown – Shifts costs to non-participating customers | Unknown | | |

Table A-3. Summary of federal funding secured by IOUs.

| Applicant | Project | Award Amount | Description |
|---|---|---|---|
| **PG&E, SCE, CEC, CPUC, CAISO, UC Berkeley** | CHARGE-2T (**C**alifornia **H**arnessing **A** dvanced **R**eliable **G**rid **E** nhancing **T**echnologies for **T**ransmission)<br><br>Press Release<br><br>DOE Factsheet | $600M Federal Share / $901M Ratepayer Share | Reconductor 100+ miles of transmission lines to increase transmission capacity to support renewables integration. Also supports interconnection reform. |
| **PG&E, Redwood Coast Energy Authority, Schatz Energy Research Center at Cal Poly Humboldt** | **T**ribal **E**nergy **R**esilience and **S**overeignty (TERAS) Project<br><br>DOE Fact Sheet | $88M Federal / $89M Ratepayer | Implement nested microgrids serving Hoopa Valley, Yurok, Karuk, and Blue Lake Rancheria tribal lands to drastically reduce outage times. |
| **Liberty Utilities** | Project Leapfrog<br><br>DOE Factsheet | $13M Federal Share / $13M Ratepayer Share | Upgrade the distribution system for real-time information gathering, greater manipulability, |

| | | | |
|---|---|---|---|
| | | | and faster outage management |
| **CPUC, CEC, CA Infrastructure and Economic Development Bank, CA Labor & Workforce Development Agency** | Solar for All<br><br>EPA Solar for All website | $249.8M | Deliver residential solar for low-income and disadvantaged communities across the state. |
| **PG&E** | Maintaining & Enhancing Hydroelectricity Section 247<br><br>DOE Award List | $34.5M for 39 different projects | Maintain and improve existing hydropower facilities. |
| **PG&E** | Project Polaris<br><br>DOE Press Release | $15 billion loan | Expand hydropower generation and battery storage, upgrade transmission capacity through reconductoring and grid enhancing technologies, and enable virtual power plants |