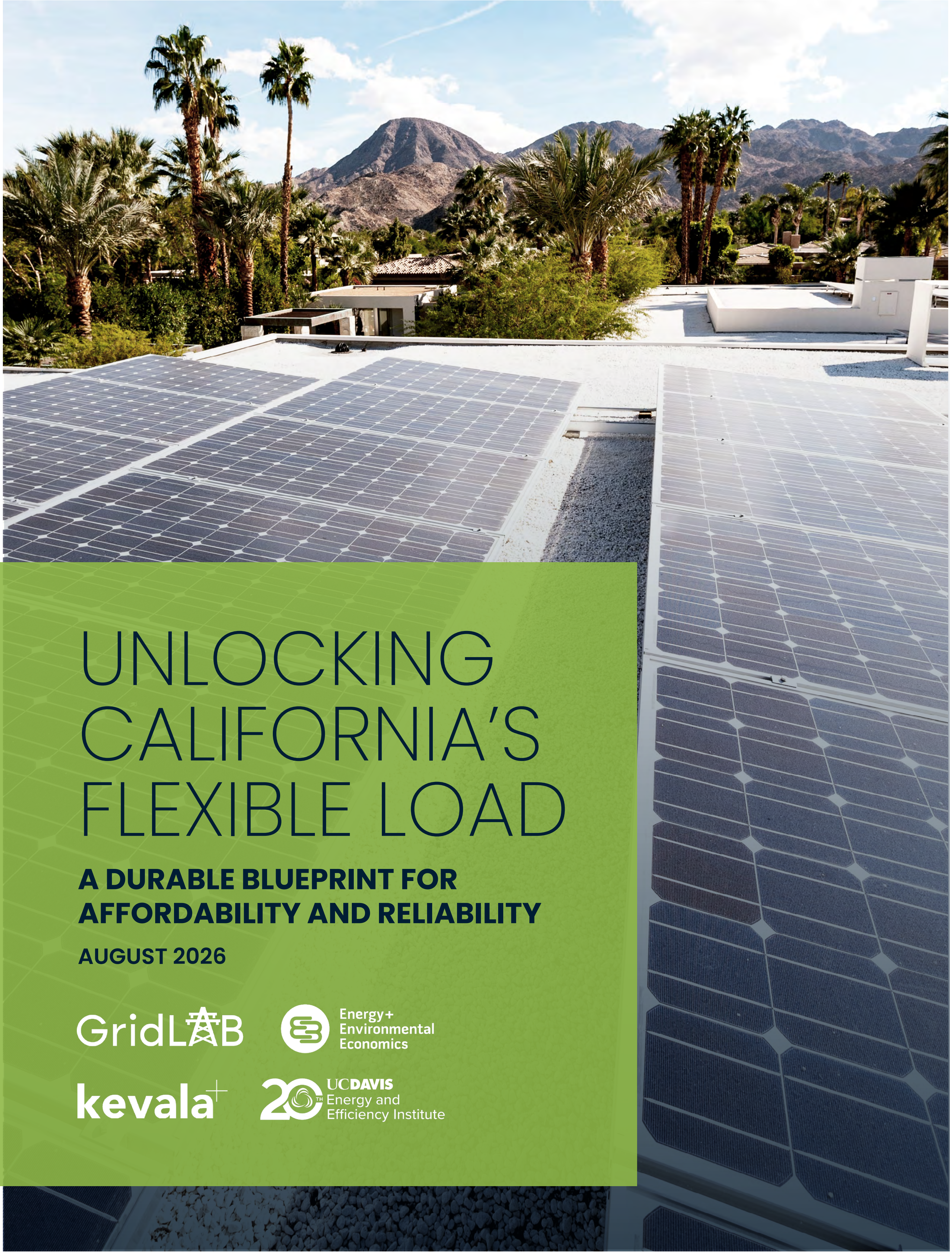

UNLOCKING CALIFORNIA'S FLEXIBLE LOAD

A DURABLE BLUEPRINT FOR AFFORDABILITY AND RELIABILITY

AUGUST 2026

GridLAB

Energy+ Environmental Economics

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1 | Executive Summary

The Opportunity. California is facing a dual challenge: sharply rising electricity rates and a rapidly evolving power grid increasingly reliant on variable renewables. This supply transition moves reliability risk beyond predictable summer peak hours into unpredictable hours year-round. Containing rate increases requires optimizing every available cost-effective tool. Flexible load can be one of those tools.

California now possesses an unprecedented base of controllable resources—including millions of electric vehicles (EVs), all-electric buildings, and distributed battery storage—that did not exist a decade ago. Enabled by widespread advanced metering infrastructure (AMI), automated device controls, and declining telemetry costs, these resources can charge, discharge, or shift use to flatten grid demand. Managed and compensated effectively, flexible load can integrate new demand and avoid expensive generation and delivery investments; left unmanaged, the cost to serve this new load will exacerbate rate pressures.

Grid Value and Statewide Limits. Flexible load creates value by shifting demand away from scarce, high-cost hours and absorbing clean energy during periods of excess generation. While top-down studies estimate sweeping potential, such as Brattle's 7,671 MW virtual power plant estimate or Kevala's $6.7 to $9.9 billion distribution savings estimate, granular investor-owned utility (IOU) analyses (e.g., PG&E's Phase 2 Electrification Impact Study) demonstrate that actual value varies substantially by time and location and is constrained by real-world achievable customer adoption constraints. Programs that treat these benefits as broad statewide averages risk overstating potential and overpaying participants.

Navigating the Net Energy Metering (NEM) Cost Shift. Any viable flexible load framework must confront the equity and affordability constraints driven by NEM and the Net Billing Tariff (NBT). California's NEM/NBT program has resulted in higher bills for most ratepayers, with a cost shift of $7 billion per year, so increasing compensation to these customers raises significant equity concerns. Moreover, existing tariffs already incentivize behind-the-meter (BTM) storage toward self-consumption, creating a higher hurdle for flexible load programs to provide incremental value. Strict guardrails are required for flexible load programs: they must pay only for incremental value not already induced by retail rates, verify performance against nongameable baselines, and guarantee net ratepayer benefits without increasing the cost shift. Flexible load compensation cannot serve as a back-door subsidy or substitute for fundamental retail rate and NEM/NBT reform.

Why Past Efforts Have Underdelivered. Historical programs have repeatedly failed to deliver reliable grid value due to four recurring flaws:

1. **Compensating Enrollment Over Performance:** Paying participants for enrollment rather than enforcing delivery when called upon with regular testing and verification of performance.
2. **Inaccurate and/or Gameable Baselines:** Relying on administrative estimates or easily manipulated baseline windows.
3. **Generator-Centric Market Rules:** Forcing residential devices and aggregations to comply with complex wholesale generator rules designed for central power plants.
4. **Program Addition Without Consolidation:** Bypassing core reforms to layer on emergency, overlapping programs without resolving double-counting or increasing complexity that limits customer participation (Appendix B).

The Path Forward. Realizing the full potential of flexible load requires consolidating California's fragmented landscape into a clear set of complementary pathways anchored by three core principles: compensating below verified avoided costs, paying exclusively for measured performance, and building on standardized, interoperable program architecture.

- **Rate-Driven Load Shift:** Time-of-use (TOU) and dynamic rate structures can drive persistent behavior shifts without counterfactual baselines or aggregator overhead, but they are unlikely to fully deliver the benefits that many hope for. Only by advancing rate design and programmatic pathways together can California fully unlock the state's load flexibility potential.
- **Avoided System Cost Programs:** To capture the value rates leave behind, load-serving entities (LSEs) should deploy three standardized mechanisms:
  - *Retail Pay-for-Performance*: Accessible, non-firm, as-available load reduction compensated against verified individual-level regression baselines.
  - *Firm Capacity*: Contracted, predictable load shift carrying Resource Adequacy (RA) value and clear performance accountability.
  - *Wholesale Market Access*: Streamlined direct California Independent System Operator (CAISO) market participation tailored for large commercial loads and sophisticated aggregations.
- **Avoided Distribution Cost Programs:** Locationally targeted dispatch specifically tailored to defer infrastructure upgrades at high-value, constrained distribution nodes.

By replacing fragmented legacy programs with standardized, performance-verified products, California can turn its expanding building and vehicle electrification into a reliable grid asset that lowers costs for all ratepayers.

2 | The Opportunity

California's electricity rates have risen sharply, and projections show continued increases. The state's energy mix includes a large and growing share of variable and energy-limited resources, extending reliability risk from a few predictable summer peak hours into more unpredictable hours throughout the year. Holding down rates in this environment requires the use of every cost-effective tool available. Flexible load can be one of those tools, reducing load on a verifiable basis during the critical hours that drive costly new resource needs.

This paper describes the evolving energy and technological landscape that lends itself more readily to flexible load solutions than has historically been the case, identifies the challenges that have stymied previous efforts to promote flexible load in California, and provides a roadmap for expanding opportunities for flexible load in a manner that will benefit all ratepayers. Interspersed throughout the roadmap are a combination of policy recommendations and opportunities to reduce implementation barriers. For the purposes of this paper, "flexible loads" are devices that can charge, discharge, or shift their electricity use in response to price signals or dispatch instructions, such as EVs, distributed battery storage, smart appliances and HVAC

CREDIT | Heidi Besen - stock.adobe.com

systems, and commercial and industrial process loads capable of managed interruption or load shift.

2.1 A Larger and More Controllable Load Base

The potential for electric loads to operate flexibly has already grown dramatically and will continue to grow. EV adoption continues to grow year over year in the state, despite the current federal headwinds. The California Energy Commission's (CEC) 2025 Integrated Energy Policy Report projects 8.4 million light-duty EVs in California by 2035.[1] All-electric buildings, which represent an increasing portion of the state's building stock and a large majority of new construction, provide significant load flexibility opportunities, primarily for electrified HVAC loads but also for smart appliances. Distributed storage is rapidly accelerating across residential and commercial sectors.

Whether electrification load raises or lowers rates for all customers will depend largely on how well it is managed. Managed effectively and compensated appropriately, these new electric loads can flatten existing load shapes to make better use of existing infrastructure. However, at a time when the cost of new infrastructure is high, unmanaged load growth could lead to higher rates by driving the need for costly new generation and delivery facilities.

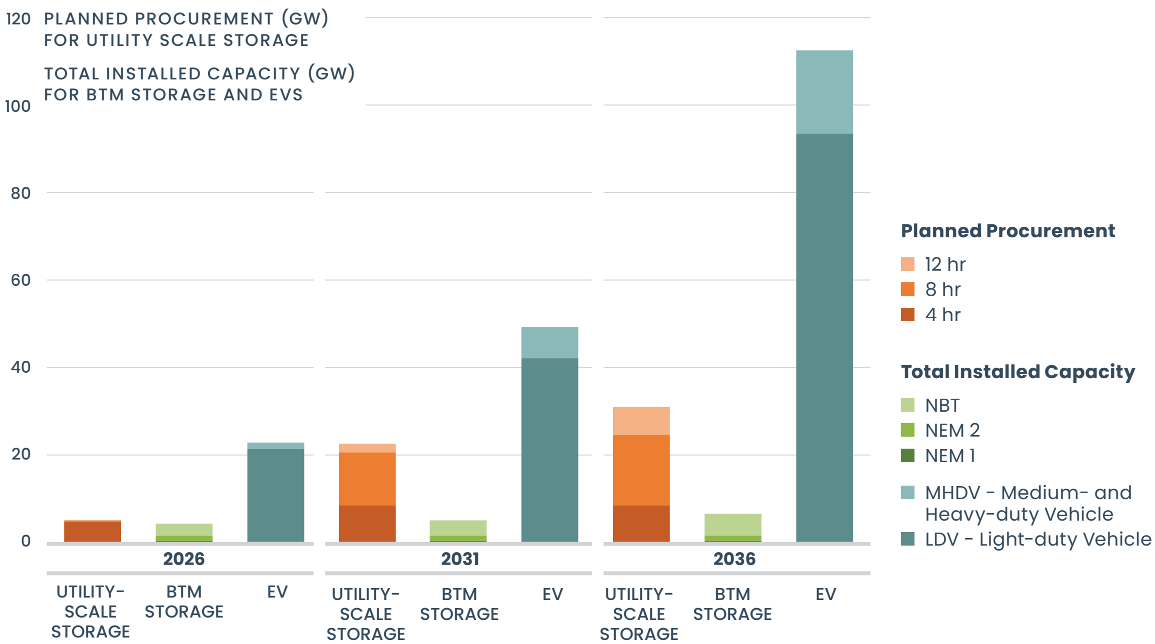
Properly incented, flexible loads can play a far larger role than they have historically, competing directly with utility-scale storage for resource adequacy and load-shifting services. The state is planning to procure 31 GW of utility-scale storage in the next 10 years; much of that capability could be met with load flexibility. Enrolling just 10 percent of the 9.7 million light-duty EVs the CEC projects with vehicle-to-grid (V2G) could supply 30 percent of the cumulative utility-scale storage procurement target for 2036, if V2G resources can be accredited and operated on a comparable basis with grid-scale storage (Figure 1).[2]

This opportunity is actionable now because the conditions that long limited flexible load have shifted. AMI is deployed at scale across much of California. Many appliances and technologies are now designed to allow for load management without ongoing customer actions and lifestyle impacts to an extent that did not exist in the past. The costs of metering, telemetry, and communications have fallen as communications standards have improved. Techniques for measurement and verification of customer load reductions have also advanced. For the first time, the flexible resource base, the technology to measure and control it, and the grid's growing need for flexibility are all in place, making it possible to serve more load with less new investment.

1 California Energy Commission, *2025 Integrated Energy Policy Report* (Adopted), Docket 25-IEPR-01, TN 271454 (Docketed July 15, 2026).

2 Assumes a Light duty vehicle (LDV) fleet, including SUVs and small pickups, with an average charging capacity of 9.6 kW and a fleet-weighted-average battery size of 120 kWh in 2036. Vehicle count from California Energy Commission, *2025 Integrated Energy Policy Report (Adopted)*, Docket 25-IEPR-01, TN 271454 (July 15, 2026), and California Public Utilities Commission, Energy Division Staff, 2026–2027 Transmission Planning Process (TPP) Proposed Decision: Modeling and Analysis (January 14, 2026). Assuming CAISO procurement targets represent 82% of statewide total. Assumes fleet wide average charging capacity of 9.6 kW for LDV and 60 kW for Medium/heavy duty vehicle (MHDV).

FIGURE 1. Planned Procurement (GW) for Utility Scale Storage vs. Installed Capacity (GW) for BTM Storage and EVs.[3]



2.2 Increased Role of Local Governments

Another thing that has changed in California is the growing role of Community Choice Aggregators (CCAs), who now serve over one-quarter of California's load. Combined with Municipal utilities, over one-half of California's load is now provided by entities that are under the direction of local governments. These entities are well positioned to engage their communities in large-scale load flexibility efforts, and they have strong incentives to do so, given that unmanaged load inflates a Load Serving Entity's (LSE's) RA obligations and wholesale power costs. The retail pay-for-performance and firm capacity pathways described in Section 4 are both well-suited for the participation of entities under local government direction, allowing CCAs and Municipal utilities to capture real wholesale savings and share that value back with participating customers.

2.3 Statewide Potential and Its Limits

A 2024 Brattle Group study commissioned by GridLab estimated statewide virtual power plant technical potential at 7,671 MW by 2035, capable of avoiding $550 million in annual

3 California Public Utilities Commission, Energy Division Staff, *2026–2027 Transmission Planning Process (TPP) Proposed Decision: Modeling and Analysis* (January 14, 2026). The storage procurement figures are drawn from the 26–27 TPP Proposed Base Case Portfolio, developed through the Commission's RESOLVE and SERVM modeling, and California Energy Commission, *2025 Integrated Energy Policy Report (Adopted)*, Docket 25-IEPR-01, TN 271454 (adopted July 8, 2026; docketed July 15, 2026).

generation, transmission, and distribution costs.[4] A recent update to a 2025 Kevala study, also commissioned by GridLab, estimated that implementing an additional 3.5 GW of system peak/net peak load flexibility to achieve the CEC's goal of 7 GW by 2030 could avoid up to $6.7 to $9.9 billion in distribution upgrade costs.[5,6]

Both estimates rest on broad, statewide-average assumptions and represent a directional opportunity rather than the achievable potential programs would deliver, especially estimates of distribution benefits. More granular utility data bears this out; the Phase 2 Electrification Impact Studies (EIS) recently performed by the three major IOUs (PG&E, SCE, and SDG&E) confirm that flexible load could defer distribution investment,[7] but the opportunity is concentrated in a narrower set of locations than top-down statewide studies imply.[8]

PG&E's Phase 2 EIS, the most granular of the three, found that its most aggressive flexible load scenario reduced summer peak demand by 2.8 GW and lowered cumulative distribution costs by $1.8 billion through 2040, or roughly 7 percent of PG&E's $25.5 billion projected distribution investment for the base case.[9] Capturing this value requires targeted enrollment on constrained circuits and dispatch aligned with local rather than system-wide peak load conditions. Furthermore, none of these studies account for customer recruitment, program

4 Ryan Hledik, Kate Peters, and Sophie Edelman (The Brattle Group), *California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability* (prepared for GridLab, April 2024).

5 For this report, several updates were made to the 2025 GridLab/Kevala California Load Management Standard Avoided Distribution Grid Upgrade Study. First, the 3.5 GW of load shift was applied only to circuits overloading during system peak/net peak. Second, a "bookend" set of avoided costs was developed by assuming assets were upgraded at 80% or 100% capacity. Finally, circuits that would continue to be overloaded even after load was shifted from the peak/net peak period were identified and removed from the avoided cost estimates.

6 Senate Bill 846 Load-Shift Goal Report" (CEC-200-2023-008), *California Energy Commission*, May 2023. Filed in Docket 21-ESR-01, docketed 5/26/2023.

7 Pacific Gas and Electric Company, *Electrification Impacts Study Part 2 Report, R.21-06-017* (filed January 28, 2026); Southern California Edison Company, *Electrification Impacts Study Part 2 Final Report, R.21-06-017* (filed January 28, 2026); San Diego Gas & Electric Company, *Final Electrification Impact Study Part 2, R.21-06-017* (filed January 28, 2026).

8 The CPUC's High DER Future proceeding (R.21-06-017) was opened to help prepare California's electric grid for millions of distributed energy resources by optimizing grid integration, improving distribution planning, and updating smart inverter operations. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning

9 Pacific Gas and Electric Company, *Electrification Impacts Study Part 2 Report, R.21-06-017* (filed January 28, 2026).

administration, and technical enablement costs that a full cost-benefit analysis must net against the estimated gross savings.

2.4 Net Energy Metering and the Shadow Over Distributed Energy Resource Deployment

A clear-eyed case for expanding compensation for flexible load dispatch in California must reckon with the legacy of the state's Net Energy Metering (NEM) program. NEM was first implemented in 1996, crediting rooftop solar production at the full retail rate under a statutory cap of roughly one-tenth of 1 percent of peak demand.[10] Crediting both self-consumption and exports at the retail rate was a calculated approach for establishing market demand for a nascent technology. It is not a payment for grid services: no performance standards were required, and retail rate compensation far exceeds the grid value provided by rooftop solar. The NEM and California Solar Incentive programs have been highly popular, drawing more than 2 million customers and roughly 18 GW of installed capacity to date.[11]

Under California's rate design that features very high volumetric charges, retail rate compensation for distributed energy resources (DERs) has shifted costs to, not provided net benefits for, non-participating ratepayers. Bills for non-participating customers were estimated to have increased by $7 billion per year by the end of 2024 as a result of California's NEM policies.[12] The Net Billing Tariff (NBT) adopted by the Commission in December 2022 has slowed the rate of this cost shift by reducing export compensation but still compensates self-consumption of PV generation and storage discharge well above avoided cost.[13] Nevertheless, the NEM retail rate credit has proven stubbornly difficult to reform, as the status quo is supported by incumbents to maintain compensation levels that business models and customer expectations were built on.

Allowing NEM/NBT customers to participate in a new program that could provide them with additional compensation raises at least two concerns. First, there is the significant equity challenge of proposing additional compensation for participating customers that are already being compensated well above the value they provide. California Public Utilities Commission (CPUC) and National Resources Defense Council (NRDC) reports show that 12-19% of customer bills are driven by the NEM cost shift, on par with wildfire and distribution related costs at 14-19%.[14] Second, NEM/NBT customers earn high retail volumetric rates, which creates a strong

10 California Legislative Analyst's Office, Assessing California's Climate Policies—Electricity Generation (Sacramento: LAO, January 2020) ("some version of NEM has been in place since 1996"); statutory cap established by SB 656 (1995).

11 California Distributed Generation Statistics (CEC/CPUC), https://www.californiadgstats.ca.gov/charts/, accessed July 24, 2026.

12 California Public Utilities Commission, 2025 Senate Bill 695 Report (September 2025). See also Severin Borenstein, "How to Fix the Solar Cost Shift," Energy Institute at Haas (blog), May 19, 2025, https://energyathaas.wordpress.com/2025/05/19/how-to-fix-the-solar-cost shift/.

13 Net Billing Tariff adopted by D.22-12-056 (December 2022). State-average legacy NEM cost of 36.4 cents per kWh versus roughly 10 cents per kWh for RPS contracts (a 3.6-to-1 ratio): California Public Utilities Commission, Public Advocates Office, "The Rooftop Solar Dilemma: Rising Electricity Rates and the Diminishing Value of Rooftop Solar" (December 16, 2024).

14 CPUC, 2025 SB 695 Report (Sept. 2025), Table 12 and Executive Summary and NRDC, *Powering Change: Understanding California's Electric Rate Challenge and Affordability Solutions* (Mohit Chhabra, March 2025), Figure 4.

incentive for NEM/NBT customers to dispatch their storage to maximize self-consumption rather than for grid benefit.

At the same time, it can be argued that excluding NEM/NBT customers leaves value on the table. Inducing changes in the use of these NEM/NBT resources could provide verified incremental net benefits to all customers at lower cost than the incremental program costs and incentives. BTM storage is projected to grow to 4.8 GW by 2030[15]; excluding these resources entirely forecloses the possibility of achieving these benefits.

There are three potential options for whether NEM/NBT customers would be eligible for additional compensation for flexibility and grid services:

- **NEM/NBT Ineligible.** Exclusion is the only equitable and reliable safeguard until the underlying cost shift is addressed. NEM and NBT customers should remain ineligible until that cost shift is resolved, keeping the prospects for flexible load clean and intact.
- **NEM/NBT Eligible.** California should seek to maximize grid benefits from BTM storage. NEM/NBT resources could provide verified incremental net benefits to all customers at lower cost than the incremental program costs and incentives. Such options should be further explored before categorically excluding NEM/NBT based on equity and cost shift grounds.
- **Conditional Eligibility for NEM/NBT.** Rather than a categorical yes or no, condition eligibility on reforms that reduce the cost shift. For example, legacy NEM customers become eligible for incremental flexible load compensation in exchange for transitioning to NBT or new alternative successor tariff. Allowing participation becomes a means to shrink the cost shift relative to the status quo, opening a path to reform that outright exclusion forecloses.

Reducing the cost shift and the incentive to dispatch for self-consumption that retail rate compensation creates makes more room for flexible load to add incremental grid value at net ratepayer benefit. Mitigating the NEM cost shift, reforming retail rates to better align with marginal costs (Section 4.2), and programmatic approaches for load flexibility all have an important role. Above all else, any new initiatives for flexible loads must be structured to pay only for incremental value from robustly measured performance and to avoid worsening the rate affordability pressures that the NEM/NBT cost shift has created.

2.5 How Flexible Load Can Reduce Costs and Lower Rates

Flexible load can deliver benefits today that the demand response programs of the past could not. The generation mix has shifted from fuel combustion toward wind, solar, and storage, resources with very low marginal costs and high fixed costs. Energy is now abundant and emissions-free in some hours, such as a spring midday, and scarce and expensive in others, such as a winter evening after sundown. The critical hours that drive investment in new

15 California Energy Commission, *2025 Integrated Energy Policy Report (Adopted)*, Docket 25-IEPR-01, TN 271454 (adopted July 8, 2026; docketed July 15, 2026).

resources are becoming more varied and harder to predict. Flexible load creates value by shifting demand into the hours and locations where clean energy is plentiful and away from those where capacity is tight.

Flexible load can also help bring new load onto the system sooner, increasing the utilization of existing infrastructure. Large new loads like data centers and EV charging hubs are seeking to interconnect faster than the grid can be expanded to serve them. Flexible loads can manage the available headroom in a bridge-to-wires or speed-to-power role, connecting new loads or distributed generation while the grid upgrade is planned and built. Accelerating interconnection of new load that spreads fixed costs over more sales and lowers average rates is a real and welcome outcome.[16] A rate reduction, however, is not a benefit in any of the three categories below and not a basis for allocating costs or setting compensation for investments in flexible load technologies. When a data center pays a premium for DERs to speed up its connection, it embodies the "beneficiary-pays" principle: the entity demanding faster service covers the cost. Shifting those costs onto general ratepayers simply because they enjoy indirect rate reductions violates that principle.

Sound compensation rests on a consistent accounting of who pays and who benefits, applied the same way to supply-side and demand-side resources. Three categories should be kept distinct:

1. **Ratepayer benefits** accrue when compensation is less than the utility's avoided costs. They arise when the resource avoids a utility investment or purchase. Avoided costs are the strongest basis for compensation because ratepayers only benefit when the utility's avoided cost is greater than the compensation paid to the participating customer.
2. **Participant benefits** accrue to the customers who take part: the compensation or bill savings they receive plus other benefits they gain. Participant benefits are central to assessing whether customers are likely to participate, but they come at the expense of non-participants whose bills must increase to provide the compensation to the participating customers.
3. **Societal benefits** include resilience, environmental, community, and other non-energy benefits. They may warrant support on policy grounds, but they fall outside the utility's revenue requirement, so funding them through rates puts upward pressure on energy affordability.

Historically, customer programs, in particular those with equity, policy, or market transformation goals, have considered participant and societal benefits in cost-benefit evaluation. Flexible loads, however, are most cleanly categorized as providing a grid service in competition with alternative utility investments. Improving energy affordability should be the primary goal for flexible load policy. Compensation for flexible load should therefore be determined based on

16 For an aggressive take on using rate reductions as a basis for cost allocation see: Akhilesh Ramakrishnan, Sanem Sergici, and Peter Fox-Penner (The Brattle Group), *A New Framework for DER Value in the Speed-to-Power Era* (July 2026).

the first category: the monetized utility costs it avoids, measured against a defined grid need, and evaluated consistently against the utility investment it would displace. Utility-scale storage, for example, sets the ceiling on the capacity value of distributed storage, after accounting for any incremental benefits or limitations of the distributed resource.

2.6 Anchoring Flexible Load Value in Resource Adequacy

System and local RA are a natural place to begin with a flexible load program. Of the grid values flexible load can serve, it is the largest and most uniform, the most robustly quantifiable, and the one where flexible load, performance adjusted, competes head-to-head with utility-scale storage, a resource whose cost is already well established. Beginning here builds on the firmest ground; additional grid values can be layered on as they are verified and targeted.

CAISO and CPUC planning proceedings define the RA needs and allocate them to individual LSEs, and the avoided cost is set by the value-adjusted cost of the utility-scale solar, storage, standalone storage, or other capacity resources procured to meet them. A large and diverse pool of customers and flexible load technologies can be aggregated into a capacity resource reliable enough to compete with those resources. Transmission and distribution capacity value are far more specific to place and time, tied to the feeders, substations, and hours where a deferrable need exists.[17]

While focusing initially on RA, a longer-term deployment strategy could enable a resource to stack and co-optimize multiple grid services where feasible and direct the resource to its highest-value service where stacking is not possible. That value can be captured both in utility planning, through what the utility can avoid building or procuring, and in utility operations, through dispatch against day-ahead and real-time market conditions.

Flexible load is a larger and more attainable opportunity than at any point before. Capturing that value at net benefit to ratepayers will require not repeating the design failures that have kept a generation of programs from delivering on the same promise.

17 Eric Cutter, Jeremy Laundergan, Mike Sontag, and Margo Bonner, *Compensating DER for Local Distribution Value While Protecting Affordability: Ensuring DER Are a Grid Resource, Not a Cost Driver* (white paper, Energy and Environmental Economics, Inc. [E3], July 2026).

3 | Why Flexible Load Has Underdelivered

California's flexible load programs to date have underdelivered because four design failures have recurred across decades:

- Program compensation was based on enrollment and availability rather than verified delivery;
- Baseline and verification rules proved gameable, inaccurate, and contested;
- Program structures were calibrated to conventional generators rather than to the mass-market loads where most of the state's flexible load potential resides; and
- Rather than repairing these structural weaknesses, policymakers responded to each new grid need by layering on programs, deepening the fragmentation.

The evidence for each underperforming endeavor runs from the commercial and industrial interruptible tariffs of the 1980s through recent virtual power plant programs, explaining how California arrived at a portfolio too fragmented to scale and too uncertain to plan around.[18]

3.1 Compensating Enrollment Rather Than Verified Delivery

California's demand response programs historically compensated customers for enrolling and remaining available rather than for verified reductions when called. Ease of enrollment, particularly for smaller customers, promoting adoption of new programs and technologies and the absence of the metering technologies and baseline approaches available today were all reasons to pay for enrollment rather than performance.

California's utility interruptible programs established this pattern early. The three IOUs operated commercial and industrial interruptible tariffs and demand response programs from the mid-1980s under stable conditions: PG&E maintained 90 to 95 percent customer compliance

18 The authors note that the scope of the recently opened CPUC Rulemaking to Enhance Demand Response (R.25-09-004) includes addressing a number of the issues identified in this section. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF

through 1998, with participants receiving modest rate credits for predictable curtailment obligations that were rarely called upon. The 2000 to 2001 energy crisis changed both the operating environment and the implicit bargain simultaneously with increased call frequency. PG&E exhausted its entire 380 MW program before the summer of 2001. SCE's compliance fell to 60 to 70 percent, with only about 1,200 of 1,800 enrolled megawatts curtailing when called. The CPUC's own analysis found that some participants were receiving the equivalent of $840 per MWh for their curtailments, more than ten times the cost of long-term contract energy, while still not performing reliably.[19]

Similar implementation and compensation challenges persist to this day. The CAISO Department of Market Monitoring's Demand Response Issues and Performance report in 2024 found that non-utility third-party demand response resources reported load reductions averaging only 54 percent of scheduled curtailments during high load conditions. Utility proxy demand response capacity was bid into the market at only 44 percent of credited RA values during critical peak hours.[20]

Flexible load is, first and foremost, a customer-owned resource under the customer's control so compensation tied to enrollment rather than to verified load impact is inherently problematic. The capacity value of bulk system resources is evaluated based on Effective Load Carrying Capability (ELCC), which quantifies the resource's reliable capacity contribution during the critical hours with a risk of a loss of load.[21] The predictable and reliable contribution of customer-sited flexible loads can and should be evaluated consistently within an ELCC framework, accounting for additional customer behavior factors such as the percent of customers who respond or opt out. The advances in probabilistic planning models, advanced metering, and interval load data all make paying for verified performance possible today in ways it wasn't before.

3.2 Baselines, Inflated Enrollment Values, and Verification Rules

Performance-based compensation for flexible loads requires a credible answer to a counterfactual question: how much energy would this customer have consumed if the program had not dispatched them? Verifying what a flexible load resource delivers raises four distinct challenges that have different causes and call for different fixes.

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19 California Public Utilities Commission, Energy Division, *Report on Interruptible Programs and Rotating Outages* (San Francisco: CPUC, February 8, 2001). The report documents PG&E compliance of 90 to 95 percent through 1998, exhaustion of the 380 MW program before summer 2001, SCE compliance of 60 to 70 percent with roughly 1,200 of 1,800 enrolled MW curtailing, and some participants receiving the equivalent of $840 per MWh.

20 California Independent System Operator, Department of Market Monitoring, *Demand Response Issues and Performance*, 2024 (Folsom: CAISO, February 20, 2025).

21 Zachary Ming, Nick Schlag, David Delgado, Aaron Burdick, Kevin Steinberger, Ben Elsey, Ari Gold-Parker, Adrian Au, Charles Gulian, and Arne Olson, *Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets* (white paper, Energy and Environmental Economics, Inc. [E3], August 2025).

- **Overstated capacity.** Aggregators can enroll or nominate more load reduction than their customers can credibly deliver, earning compensation against commitments they cannot honor. For example, several years ago Federal Energy Regulatory Commission (FERC) settled with two demand response aggregators for bidding CAISO resources they could not reliably fulfill.[22]
- **Lack of testing.** Programs that pay for enrolled or nominated capacity without regularly testing performance for enrolled megawatts let overstated capacity go undetected until it underperforms during critical events.
- **Baseline counterfactuals.** Performance is measured against an estimate of the energy a customer would have used had the program not dispatched them. Every baseline is an estimate with some opportunity to influence the result — for instance by shifting consumption into the measurement window before an event so the apparent reduction exceeds the real change.
- **Proliferation of baseline methods:** SCE's 2024 load impact evaluation documented seven different baseline approaches across its major demand response programs, reflecting the absence of any common standard.[23] Some programs have different baselines for compensation and for evaluation, measurement, and verification.

Because the four challenges have different causes, they call for different remedies, yet the response has too often piled new rules onto the baseline while leaving overstated capacity

22 Federal Energy Regulatory Commission, enforcement settlements with Leapfrog Power, Inc. ($73,880 civil penalty and disgorgement) and OhmConnect, Inc. ($141,094 civil penalty and disgorgement), both 2023, for bidding demand response resources into the CAISO market without a reasonable expectation of fulfillment.

23 Southern California Edison Company, *Program Year 2025 Load Impact Reports Executive Summary, A.22-05-002* (filed April 22, 2026), § 3.3 (documenting distinct evaluation methodologies for each major program).

and untested capability unaddressed. The result has been a decades-long cycle of disputes and added verification requirements that spawned further circumvention and left no party confident in the numbers. Section 4.3 describes how interval metering, better telemetry, and statistical control-group methods now make measurement rigorous enough to break that cycle.

3.3 Programs and Markets Designed to Treat Flexible Loads as Generators

California's wholesale market rules and utility program structures were designed around the operational characteristics of conventional generation: large, centrally metered, professionally managed assets with predictable output. Flexible load can lower LSE's RA obligation simply by reducing its forecast peak, but to count on the supply side, the CPUC has required a resource to participate in the CAISO market as a Proxy Demand Resource or a Reliability Demand Response Resource. This requirement traces back to FERC Order 719, which directed the CAISO to open its wholesale markets to demand response on a comparable basis with generation. The CPUC followed by implementing a bifurcation of demand response into supply-side and demand-side categories[24] and tying supply-side resource adequacy credit to direct CAISO market participation, with the objectives to hold demand response to the same requirements as generation and to introduce more competition in demand response solicitation.[25] This process brought residential BTM storage, EV fleets, and small commercial loads under rules calibrated for large generators, imposing participation costs that exclude the mass-market resources where most of the state's flexible load potential resides.

As far back as the 2009 CAISO Demand Response Barriers Study observed that the market construct was built around generation dispatch logic that did not map to how loads behave.[26] Existing utility programs were misaligned with CAISO market products, so aggregators could not convert utility program participants into wholesale market resources. The metering, telemetry, settlement infrastructure, and baseline measurement requirements for wholesale participation created costs that market revenues could not reliably recover. The 2014 Olivine report, Distributed Energy Resources Integration: Summarizing the Challenges and Barriers, reached the same conclusions from direct aggregator experience.[27] More recently, the CAISO's Demand and Distributed Energy Market Integration (DDEMI) straw proposal of March 2026 documents the same pattern: rules designed for large generators are still applied to residential

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24 CPUC, *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Rulemaking R.13-09-011, Decision D.14-12-024 (issued December 9, 2014).

25 CPUC, *Decision Sunsetting the Investor-Owned Utilities' Demand Response Auction Mechanism Pilot Programs*, Decision D.24-04-006 (issued April 24, 2024).

26 CAISO, *Demand Response Barriers Study* (per FERC Order 719), prepared by Freeman, Sullivan & Co. and Energy and Environmental Economics, Inc. (April 28, 2009).

27 Robert W. Anderson, Spence Gerber, and Elizabeth Reid (Olivine, Inc.), *Distributed Energy Resources Integration: Summarizing the Challenges and Barriers* (January 24, 2014).

and small business customers for whom those rules were never intended.[28]

Flexible load earns RA value through several distinct pathways, from lowering the system-wide demand forecast that sets new resource procurement targets to earning formal qualifying capacity under resource adequacy or Slice-of-Day frameworks (see Appendix A for details). A generation or supply-side demand response resource carries a Must Offer Obligation to bid its committed capacity into the CAISO energy markets to deliver generation when the system needs it. The CAISO argues that direct market participation is the most efficient pathway, since only its software can optimize dispatch across all supply and demand bids. That argument does not account for the cost of fitting aggregations of small, BTM resources into a market that was not designed for them. It also overlooks a limit of the market pathway itself: FERC's non-discriminatory access rules bar the CPUC from requiring CAISO-market resources to bid so that dispatch is likely. This allows a resource to hold RA credit while bidding high prices in the CAISO market to avoid being called. California policymakers should be clear-eyed about why these wholesale barriers for load participation persisted for more than 15 years and support two pathways: direct wholesale participation for larger, operationally sophisticated resources, and well-structured demand-side programs, accredited by the CPUC, that capture much of the same flexibility at lower cost and complexity.

3.4 A Pattern of Program Addition Without Consolidation

California's demand-side programs exhibit a recurring pattern: programs are initially designed with generous compensation to promote adoption, that compensation becomes embedded in customer expectations, political constituencies form around it, and reform becomes extremely difficult even after the original rationale no longer holds. Rather than repairing the structural weaknesses each iteration exposed, policymakers and utilities responded to the next grid need by layering on new programs.

This history, most prominently exemplified by NEM/NBT, has made regulators understandably cautious about approving new flexible load compensation structures that will create new constituencies to lobby for continuation even in the face of clear evidence of poor performance or overpayment that shifts costs to other customers. Once a new program is established and embedded in customer and aggregator expectations, it can become difficult to reform or replace.

Beyond regulatory hesitancy, this habit of layering rather than consolidating has produced significant complexity. Each IOU in California administers 14 or more different programs (Appendix B). Dispatch timing ranges from day-ahead notice to 15-to-30-minute real-time calls. Commitment periods span from annual, 24-hours-a-day obligations to summer-only

28 The DDEMI process is a collaborative stakeholder initiative focused on integrating DERs into CAISO's wholesale electricity markets, including the evaluation of different participation models, addressing technical and regulatory barriers, and updating market rules to better accommodate DERs. https://stakeholdercenter.caiso.com/StakeholderInitiatives/Demand-Distributed-Energy-Market-Integration

windows. One reliability program accepts new customers only during a single month each year and programs providing RA capacity require 80 days' advance notice for enrollment. An EV fleet manager or BTM storage aggregator seeking to enroll customers across programs faces incompatible requirements at every step: different enrollment windows, different baseline approaches, different metering specifications, different performance measurement periods.

California's response to the reliability shortfalls of 2021 and 2022 produced two parallel emergency programs that are the most recent iteration of this pattern. The CPUC launched the Emergency Load Reduction Program (ELRP) in May 2021, initially for non-residential customers. When expanded to residential customers in May 2022, enrollment reached roughly four million accounts across the three IOUs.[29] The Legislature authorized the Demand Side Grid Support (DSGS) program through Assembly Bill 205 in June 2022 and assigned administration to the CEC. This approach reflected converging pressures: a 2022 state budget surplus that created fiscal headroom for emergency spending outside the normal ratemaking cycle, Governor Newsom's reliability-first mandate following the 2020 rolling blackouts, and a legislative intent to press publicly owned utilities to develop comparable programs. DSGS enrolled over 700 MW across more than 260,000 participants within two years.[30]

The two programs also created structural tensions. Resources already carrying RA obligations could participate in DSGS for nominally incremental capacity, but the two agencies developed verification methods in parallel. The double-counting concern was raised during guideline development, only partially addressed, and never fully resolved. DSGS and ELRP ran simultaneously, targeting overlapping customer populations under different oversight, using different measurement standards, and administered by two different agencies.

The deeper problem is the impulse to bypass the existing framework rather than repair it. Emergency programs produced enrollment results that conventional programs could not, but they left the key foundational questions unanswered: no durable performance framework, no stable funding path, no resolution of the double-counting problem, and no consolidation of the program landscape.

The solution to this historic practice is consolidation and standardization of offerings, along with the discipline and political will to "solve" new challenges as they emerge through improvements to those consolidated and standardized offerings, not development of new, bespoke programs.

29 California Public Utilities Commission, D.21-12-015 (Phase 2, R.20-11-003), December 2, 2021. The decision expanded ELRP to residential customers for Summer 2022; approximately four million consumers were automatically enrolled across the three IOUs.

30 California Energy Commission, *Proposed Demand Side Grid Support (DSGS) Program Guidelines, Fourth Edition*, Docket 22-RENEW-01, TN 259451 (October 4, 2024). Program established by Assembly Bill 205 (Chapter 61, Statutes of 2022); enrollment of 700 MW across 260,000-plus participants documented in CEC program reporting.

4 | The Path Forward

To capture the value of emerging flexible load while avoiding historical pitfalls, California should move to a streamlined portfolio of consolidated programs. Informed by decades of lessons learned, this framework should compensate customers based on the specific flexibility they offer with payments strictly tied to verified grid benefits.

4.1 Three Principles for Flexible Load Compensation

Realizing flexible load value at acceptable ratepayer cost rests on three principles that apply across every pathway:

1. **Compensation should be below avoided costs.** Compensation should pay for incremental grid value verified against a baseline, at levels anchored to avoided cost or competitive market prices (i.e., set far enough below to cover administrative costs and provide non-participating ratepayer benefits). The incremental value is over and above

what is already induced by NEM/NBT and TOU rate-induced behavior, so ratepayers do not pay again for flexible dispatch that customers are already compensated to provide. This discipline is also an equity safeguard, since controllable loads tend to be adopted first by higher-income customers. Excess caution imposes its own ratepayer costs through delay and forgone incremental grid benefits at net-savings for all ratepayers.

2. **Payment should follow measured performance rather than enrollment**, tied to verified load impacts during the critical hours that drive grid costs. Because a flexible load resource is customer-owned and customer-controlled, its contribution must be established by quantifying the expected value it will provide and verifying the load impact it delivers. Directly metered resources such as battery storage and EV discharge would support settlement without counterfactual assumptions, if the retail rates they pay and receive can be made to reflect full avoided cost. Under other retail rate designs, baseline-dependent resources such as smart thermostats and water heaters require statistical and control group methods, which warrants conservative initial crediting subject to upward revision as accuracy is confirmed.

3. **Programs should consolidate** onto a small number of well-defined products with open, interoperable standards for enrollment, measurement, dispatch, and settlement. Individual LSEs can then run their own programs while a vendor or aggregator still reaches customers through common participation pathways rather than separate integrations for each program and territory. Public investment should fund that shared infrastructure and those standards rather than subsidize fragmented pilots and programs. Sustaining these products depends on business models predictable enough to finance while anchored to verified value. Third-party intermediaries will be essential to scale but justify their margin only where they aggregate small resources and handle enrollment, measurement, and dispatch more cheaply than customers or utilities can on their own.

4.2 Rate-Driven Load Shift

Using rates to unlock load flexibility should be "first in the load flexibility loading order," to draw an analogy to the state's long-standing policy for electricity resource planning. Achieving load flexibility through rate design avoids all of the challenges described in Section 3 — compensation flows through the price itself, so there is no baseline or counterfactual estimate, no gaming to guard against, and no double-counting to resolve. Any programs supporting load flexibility can focus on a single clear objective: enrolling customers in tariffs that encourage load shifts or reductions to avoid the highest marginal cost hours as reflected in tariff prices. LSEs realize the benefits of rate-driven load shifts most directly in the form of reduced procurement obligations resulting from their reduced peak load, as well as indirectly as a result of avoiding rate increases from any avoided transmission and/or distribution upgrades.

Retail rate reform remains a primary long-term objective for the CPUC, which recently opened a proceeding focused on aligning rate structures with the state's clean energy goals, including promoting dynamic pricing and flexible demand to relieve grid stress.[31] This effort may result in material amounts of load shift; however, it is unlikely to capture the state's full load flexibility potential. First, one-quarter of the state's load is not under CPUC jurisdiction. Furthermore, it is unlikely that rate design alone will capture the remaining three-quarters of the state's load flexibility potential given that marginal cost-based rates:

- Have historically been slow to track changing grid conditions;[32]
- Cannot steer response to a specific local capacity zone or overloaded distribution feeders, commit a resource to firm delivery during a narrow set of critical hours, or count as a contracted resource in system planning; and
- Have been shown to not maximize their potential in studies that compare rate design impacts with and without complementary technologies that are often promoted through load flexibility programs.[33]

Dynamic rates address some of these shortcomings by adjusting prices closer to real time, providing a continuous signal that shifts load year-round and, when set properly, compensating at prices that better approximate avoided cost. The CPUC's CalFUSE framework, a dynamic rate and demand flexibility framework supported by the CEC's MIDAS platform, is actively being tested in dynamic rate

31 California Public Utilities Commission, *Advanced Rate Design / clean-energy rate-alignment proceeding*. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K677/604677976.PDF

32 Arne Olson, Eric Cutter, Lindsay Bertrand, Vignesh Venugopal, Sierra Spencer, Karl Walter, and Aryeh Gold-Parker, *Rate Design for the Energy Transition: Getting the Most Out of Flexible Loads on a Changing Grid* (Energy Systems Integration Group, Retail Pricing Task Force, March 2023). https://www.esig.energy/aligning-retail-pricing-with-grid-needs

33 https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf

pilots through 2026 and 2027.[34] While promising, dynamic rates are not yet mature; several more years of deployment, device integration, and demonstrated acceptance will be needed before they can serve as a robust pathway for mass-market flexible load.

Fortunately, flexible load programs and evolving rate designs can be complementary. Rates create persistent benefits from and for those customers who respond to price signals and opt into more aggressive tariffs independent of any program "nudge," while programs tap the remaining flexible load by either (1) shepherding customers toward more dynamic opt-in rate designs and providing any needed facilitating equipment and/or software, or (2) actively managing flexible DERs via as-available or firm capacity programs that support load-serving entity (LSE) and/or distribution utility resource planning.

4.3 Flexible Load Implementation

Realizing flexible load through programs, rather than rates, requires estimating the customer impact relative to a counterfactual baseline to calculate what a customer actually delivers incremental to the load shift induced by rates. AMI, including the higher-resolution AMI 2.0 systems now being deployed, and more robust and accurate sub-metering provide interval data granular enough to accurately estimate an individual customer's response. Statistical methods turn that data into verified estimates of performance: regression-based, weather-normalized models estimate per-customer, per-event load impacts, and matched statistical control groups of comparable non-participants isolate the response an event caused from the consumption that would have occurred anyway. These methods are auditable and far less gameable than the day-matching baselines that undermined earlier programs.

California has already operationalized this approach. CAISO has adopted Recurve's FLEX platform as an approved baseline methodology.[35] Event-day usage for participating customers is compared against a modeled prediction of usage absent the event, then adjusted by the change measured in a matched non-participant comparison group, with results auditable at the program, project, and meter level and usable for both LSE settlement and CAISO market participation. That gives aggregators, LSEs, regulators, and CAISO a performance baseline, and the interval smart-meter reads it requires are in place across the IOU territories and being deployed across most publicly owned utility territories.

Every performance test and counterfactual baseline is an estimate with some opportunity to influence the measured result. The potential for inflating enrollment or gaming baselines cannot be eliminated entirely. Even so, today's tools measure performance far more capably than was possible a decade ago: weather-normalized regression on interval AMI data and

34 California Public Utilities Commission, Energy Division, *Advanced Demand Flexibility Management* (San Francisco: CPUC, June 2022) (the CalFUSE framework).

35 California Independent System Operator, *Demand Response — Advanced Measurement Methodology* (updated February 2022). https://www.caiso.com/Documents/Demand-Response_Advanced_Measurement_Methodology_updated_Feb_2022.pdf

statistical control groups drawn from comparable non-participants estimate aggregate load impacts with a confidence and auditability not possible with the day-matching baselines of past programs.

Overcorrection imposes its own costs and risks. Holding out for a perfect counterfactual that does not exist, and writing rules to foreclose every conceivable manipulation, increases cost and friction for the large majority of well-intentioned participants, while sophisticated actors retain the ability to navigate whatever regime is in place. California can now demand both greater rigor and ease of implementation at the same time. Performance testing and modern baseline methods can provide the accountability regulators require and the low-cost, broad participation the opportunity for flexible load depends on.

Measurement establishes what was delivered; open standards and utility operating systems establish how flexible load is dispatched and integrated. Utility investments in advanced distribution management systems (ADMS) and distributed energy resource management systems (DERMS) give operators the real-time visibility and control to call on flexible load at the locations and times the grid needs it and to coordinate it with utility operations. Open, interoperable communication standards and application protocols, such as OpenADR, OCPP, SunSpec Modbus, and IEEE 2030.5, along with IEEE 1547, increasingly enable devices, aggregators, and utility systems to connect through common interfaces. Fragmentation, however, remains a real barrier that California policymakers will need to help overcome; a recent national laboratory survey of 751 inverters from 50 companies found that fewer than one in four supported a non-proprietary communication protocol.[36] Nevertheless, the trajectory is clear: continued progress on performance testing, advancing baseline methods, utility ADMS and DERMS, and consolidation around open standards can deliver the verifiable measurement and standardized dispatch on which the program pathways discussed below depend.

4.4 Programs for Bulk System Value

There are three program pathways to avoiding system reliability and capacity costs, all of which share the three principles discussed previously and the common enrollment, dispatch, and settlement infrastructure that consolidation provides. The pathways differ in the firmness of the load flexibility offered as well as the level of complexity involved in engaging in the particular pathway. As a result, the compensation associated with each pathway differs as well.

Retail pay-for-performance

Retail pay-for-performance programs compensate customers for verified load reductions while requiring no firm commitment to shift load, and those reductions in turn benefit LSEs by

36 Hatagishi, Yukihiro, Pranav Gadamsetty, Saroj Shinde, and Jesse Bennett. 2026. *V2XConnect: Harmonizing the Landscape of Bidirectional Charging Codes, Standards, and Communication Protocols*. Golden, CO: National Laboratory of the Rockies. NLR/TP-5400-99341. https://www.nlr.gov/docs/fy26osti/99341.pdf.

lowering their share of peak reliability procurement.

Payment follows verified performance, so each kilowatt of reduction confirmed against a customer-level baseline earns a payment reflecting the avoided cost it delivers, and enrollment and availability alone generate no payment. Because there is no firm advance commitment, compensation is lower than under firm capacity programs, and the design priority is accessibility through simplified enrollment, straightforward measurement, and pathways that work for residential and small commercial customers without requiring aggregators or technical sophistication.

The residential and small commercial programs closest to this model today show per-customer impacts under one kilowatt, yet millions of such customers could respond when enrollment is simple and the ask is clear, so the challenge is converting demonstrated willingness into a durable delivery model with persistent enrollment, automated dispatch, and performance measurement that does not depend on emergency funding. Organizing this layer around a few standardized products with a common enrollment interface can largely supplant the load shifts and/or reductions that ELRP- and DSGS-type emergency programs currently deliver by building accessible, performance-based participation that operates durably and at lower cost within the ratemaking framework rather than outside it.

Firm capacity

Firm capacity programs give LSEs and system planners a basis for counting flexible load toward RA, and local distribution companies a basis for deferring distribution upgrades because planning value depends on firm commitment rather than probabilistic response. Firm commitments backed by performance accountability and capacity-adjusted opt-out provisions increase the capacity value planners can count on and justify the avoided-investment claim that as-available programs cannot support.

This pathway can be structured as a capacity product under RA and Integrated Resource Plan frameworks, allowing the CPUC and publicly owned utilities to set operating and verification requirements directly rather than relying on wholesale market rules. Under this approach, regulators can tailor dispatch frequency and duration to their specific firm capacity needs while enforcing robust performance accountability. Crucially, these requirements must establish meaningful oversight without becoming so punitive that they deter participation from reliable customers. To ensure long-term success, this framework must also incorporate lessons from past programs to resolve recurring issues like ELCC-consistent crediting, rigorous verification, and double-compensation.

Wholesale market access

Direct wholesale participation is efficient for resources that can meet CAISO's registration, telemetry, settlement, and compliance requirements. For large commercial and industrial loads and sophisticated storage aggregations, the wholesale market offers price transparency and access to market products that retail programs cannot replicate. The barrier is that those requirements remain prohibitive for most mass-market flexible loads and have not materially eased across 15 years of reform.

The appropriate response is to right-size participation standards rather than dilute them, keeping the standards appropriate to the reliability commitment wholesale participation carries while streamlining the path from retail participation to wholesale participation. The CAISO and CPUC can also remove specific rules that create barriers while continuing to protect customers from genuine reliability risk, consistent with the direction of the previously referenced DDEMI process. Wholesale access is a valuable complement for capable resources and a partial solution rather than the primary pathway. Treating it as the default scaling route has historically absorbed the regulatory attention needed to reform California's retail flexible load infrastructure.

4.5 Programs for Distribution Value

Avoided distribution upgrade programs can produce durable savings at the specific locations and times where dispatch will avoid otherwise-needed infrastructure upgrades. This pathway requires locational dispatch, circuit-level measurement, and sophistication that most programs lack.

The previously mentioned GridLab/Kevala study and IOU Electrification Impact Studies show that this value is concentrated at a discrete set of high-value nodes rather than spread across the system. Compensation should be tied to the verified avoided distribution cost at the location where dispatch avoids an upgrade, since avoided distribution upgrade payments to load flexibility resources deployed on circuits that are not at risk of overloading simply transfer money to participants without the cost savings that justify those payments.

This pathway is separated from the firm system pathways above because resources committed to a local distribution need during system peak cannot simultaneously be counted as firm system capacity. Over time, though, flexible load resources used to avoid distribution upgrades on circuits with coincident system peaks will lower system peak forecasts, which in turn will reduce the new reliability procurement and RA obligations of LSEs serving customer load on those circuits.

5 | Conclusion

California stands at a critical juncture where rapid building and vehicle electrification will either exacerbate an ongoing affordability crisis or become the state's most powerful tool for grid management. Realizing the full potential of flexible load requires breaking from decades of fragmented program layering, payment for enrollment alone, and wholesale market barriers. By consolidating California's landscape around a small set of standardized, performance-verified pathways, anchored strictly to monetized avoided costs and advancing in parallel with retail rate reform, policymakers can protect non-participating ratepayers while unlocking gigawatts of flexible capacity. Delivered through both empowered local LSE's and large IOU's alike, and built on open, interoperable standards, this framework will transform distributed batteries, EVs, and smart appliances from unmanaged grid risks into reliable, cost-reducing assets for all Californians.

APPENDIX A.
How Load Flexibility Reduces Capacity Requirements

California's Resource Adequacy (RA) program requires each load-serving entity (LSE) to procure firm capacity covering its share of system peak plus a planning reserve margin. Obligations flow from the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) demand forecast: the CPUC sets a planning reserve margin through an annual loss-of-load-expectation (LOLE) study, then allocates RA obligations to each LSE based on its share of that forecast. Whether and how a load reduction earns RA value depends on which of three categories of load flexibility it falls into. Following the Senate Bill 846 Load-Shift Goal Report, the CEC's 2025 IEPR organizes load flexibility into these same three groups.[37]

GROUP 1 | Load-modifying resources. These are the interventions LSEs use to reduce projected peak demand and optimize load shape at the system level or on distribution circuits, most commonly time-varying rates such as time-of-use, critical peak pricing, and dynamic rates, together with load-modifying demand response programs.[38] They reduce the CEC demand forecast, lowering the system-level RA obligation before procurement targets are set, and are captured in the forecast at various stages: within baseline demand, as an incremental load modifier, or in the final adjusted forecast for each LSE. To avoid double-counting, the forecast credits a new rate structure or other load-modifying activity only for its expected first-year impact, because the forecast updates annually against historical metered sales, so later reductions in peak load are absorbed into the baseline in subsequent years.

GROUP 2 | Resource planning and procurement load flexibility. This flexibility either counts toward RA requirements or reduces them, as determined by the LSE's regulatory body. Utility-run demand response portfolios are typically credited as RA, reducing the obligation, while third-party demand response contracts count directly toward meeting it. Under CPUC rules,

37 California Energy Commission, *2025 Integrated Energy Policy Report (Adopted)*, Docket 25-IEPR-01, TN 271454 (adopted July 8, 2026; docketed July 15, 2026).

38 *2025 Integrated Energy Policy Report* (Adopted), Docket 25-IEPR-01, TN 271454 (July 15, 2026).

market-integrated (supply-side) demand response must register in the CAISO energy market as either an economic resource, which participates in CAISO markets much like a generator, or a reliability resource, which CAISO activates only under emergency conditions. Resources in this group earn formal qualifying capacity through the Slice-of-Day framework and subject to auditable accreditation comparable to that applied to generation.[39]

GROUP 3 | Incremental emergency resources. These programs, principally the Emergency Load Reduction Program (ELRP) and the Demand Side Grid Support (DSGS) program, provide load reductions during extreme events that traditional planning standards do not fully anticipate. They function as an insurance policy rather than planned capacity: they do not reduce the CEC forecast or any LSE's forward procurement obligation, and so receive no formal recognition in resource planning.[40]

Across these three groups, capacity value is not credited with consistent rigor, transparency, or verification. The near-term priority would be a performance-tested accreditation track for load resources that applies Effective Load Carrying Capability (ELCC) consistent methods with the same transparency for both supply- and demand-side resources, moving new program enrollments and supply-side RA claims toward demonstrated dispatch performance as the basis for credit.

For LSEs, this can be structured as a capacity product that does not require direct CAISO energy market participation, keeping it outside FERC jurisdiction and allowing the CPUC, LSEs, and publicly owned utility planners to set verification requirements directly. Load participating in CAISO markets is subject to FERC's non-discriminatory access rules, which prevent the CPUC from requiring demand response providers to bid in ways that make dispatch likely, so providers can hold RA credit while structuring bids to minimize the chance of being called. Accreditation under a non-market capacity product should instead rest on verified dispatch performance, with credit toward RA set by the same ELCC standards applied to generation.

39 2025 Resource Adequacy and Slice of Day Filing Guide (CPUC), Energy Division Report on RA Slice of Day Implementation.

40 California Energy Commission, *Proposed Demand Side Grid Support (DSGS) Program Guidelines, Fourth Edition*, Docket 22-RENEW-01, TN 259451 (October 4, 2024); California Public Utilities Commission, *Decision 21-12-015* (Phase 2, Rulemaking 20-11-003), December 2, 2021.

APPENDIX B.
IOU Customer Flexible Load Programs

California's three large investor-owned utilities (IOUs) operate a wide range of customer flexible load and demand response programs. Table 1 lists these programs and, for each, the number of enrolled customers, the enrolled load, and the measured load impact. Program results are compiled from evaluation reports from 2023-2025, downloaded from IOU and California Measurement Advisory Council (CALMAC) websites.

TABLE 1. List of California IOU Programs, Reporting Enrolled Customers, Enrolled Load, and Measured Impact

Acronyms

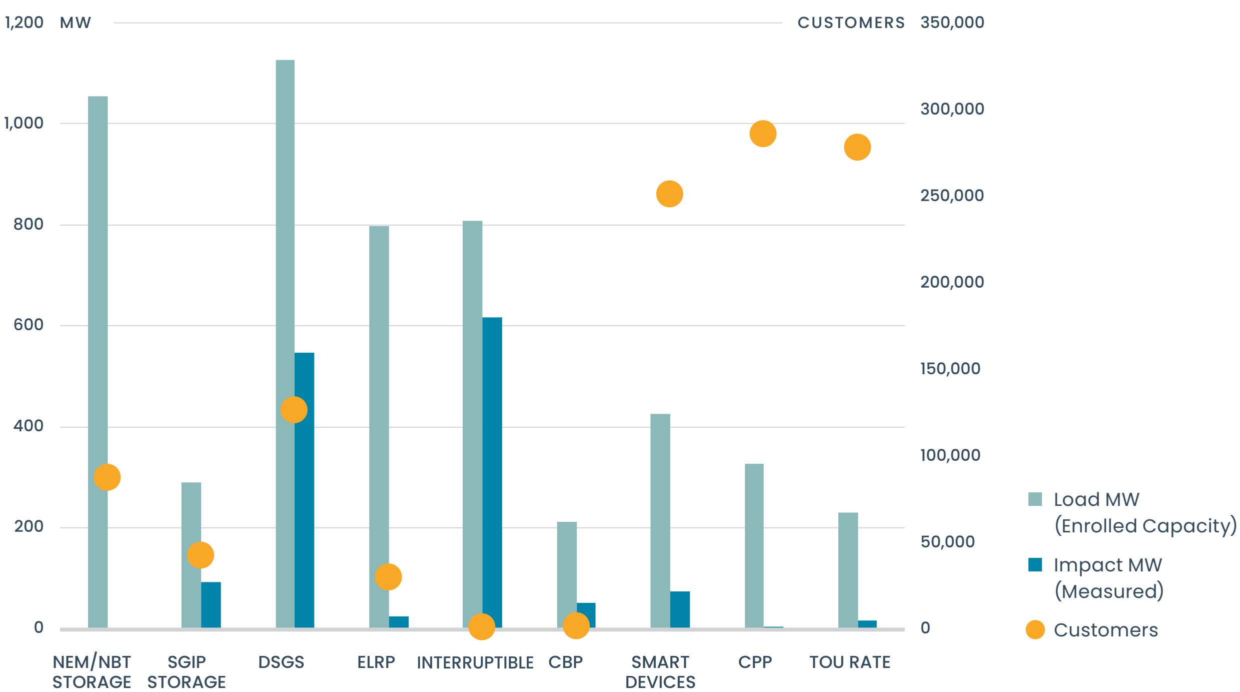
AP	Agricultural Program
ART	Automated Response Technology
BIP	Base Interruptible Program
CBP	Capacity Bidding Program
CPP	Critical Peak Pricing
DSGS	Demand Side Grid Support
NBT	Net Billing Tariff
ELRP	Emergency Load Reduction Program
RTP	Real-time Pricing
SDP	Smart Devices Program
SEP	Smart Energy Program
SGIP	Self Generation Incentive Program
TOU	Time of Use
VGI	Vehicle Grid Integration

YEAR	IOU	TYPE	CATEGORY	PROGRAM	ENROLLED	LOAD MW	IMPACT MW
2025	PG&E	Storage	Load Modifying	NBT Storage Res	26,318	265	-
2025	PG&E	Storage	Load Modifying	NBT Storage Com	141	45	-
2023	PG&E	Storage	Load Modifying	SGIP Total	21,119	129	41
2025	PG&E	DSGS	Emergency	DSGS Res	50,529	410	195
2025	PG&E	DSGS	Emergency	DSGS Com	95	21	8
2025	PG&E	DSGS	Emergency	Goodleap	1,265	-	2
2025	PG&E	ELRP	Emergency	ELRP Total	19,983	722	22
2025	PG&E	Interruptible	Supply Side	BIP	204	217	168
2025	PG&E	CBP	Supply Side	CBP Non-Res	431	124	41

YEAR	IOU	TYPE	CATEGORY	PROGRAM	ENROLLED	LOAD MW	IMPACT MW
2025	PG&E	CBP	Supply Side	CBP Res	1,336	2	0
2025	PG&E	TOU Rate	Load Modifying	EV TOU Rates	186,462	83	6
2025	PG&E	CPP	Load Modifying	SmartRate	45,242	90	4
2025	PG&E	Smart Devices	Load Modifying	SmartAC	52,235	106	6
2025	PG&E	Smart Devices	Load Modifying	ART	41,872	79	19
2025	SCE	Storage	Load Modifying	NBT Storage Res	46,345	531	-
2025	SCE	Storage	Load Modifying	NBT Storage Com	809	35	-
2023	SCE	Storage	Load Modifying	SGIP Total	13,903	115	37
2025	SCE	DSGS	Emergency	DSGS Res	58,650	525	261
2025	SCE	DSGS	Emergency	DSGS Com	191	34	11
2025	SCE	DSGS	Emergency	Goodleap	938	-	1
2025	SCE	ELRP	Emergency	ELRP Total	9,288	77	5
2025	SCE	Interruptible	Supply Side	BIP	326	563	431
2025	SCE	Interruptible	Supply Side	AP-1	865	28	19
2026	SCE	CBP	Supply Side	CBP-E-Non-Res	495	87	11
2026	SCE	CBP	Supply Side	CBP-E-Res	251	0	0
2025	SCE	CPP	Load Modifying	CPP-Small	208,602	1	-
2025	SCE	CPP	Load Modifying	CPP-Medium	21,982	24	-
2025	SCE	CPP	Load Modifying	CPP-Large	1,835	195	1
2025	SCE	CPP	Load Modifying	CPP-Res	915	1	-
2025	SCE	RTP	Load Modifying	RTP	90	-	-
2025	SCE	Smart Devices	Supply Side	SDP-R	143,260	143	43
2025	SCE	Smart Devices	Supply Side	SDP-C	6,127	97	8
2025	SCE	Smart Devices	Supply Side	SEP	7,764	2	1
2025	SDG&E	Storage	Load Modifying	NBT Storage Res	13,913	158	-
2025	SDG&E	Storage	Load Modifying	NBT Storage Com	101	20	-
2023	SDG&E	Storage	Load Modifying	SGIP Total	7,942	48	15
2025	SDG&E	DSGS	Emergency	DSGS Res	14,714	119	62
2025	SDG&E	DSGS	Emergency	DSGS Com	46	18	7
2025	SDG&E	DSGS	Emergency	Goodleap	74	-	0
2024	SDG&E	ELRP	Emergency	ELRP Total	1,340	-	-
2024	SDG&E	TOU Rate	Load Modifying	EV TOU Rates	60,327	111	10

YEAR	IOU	TYPE	CATEGORY	PROGRAM	ENROLLED	LOAD MW	IMPACT MW
2024	SDG&E	TOU Rate	Load Modifying	TOU Rate	31,448	37	1
2024	SDG&E	CPP	Load Modifying	TOU-DR-P	6,638	14	1
2024	SDG&E	CPP	Load Modifying	EV-TOU-5-P	690	2	0
2024	SDG&E	RTP	Load Modifying	VGI	223	-	0
2025	SDG&E	CBP	Supply Side	CBP Non-Res Elect DA	-	-	-
2025	SDG&E	CBP	Supply Side	CBP Non-Res Elect DO	-	-	-

Enrolled Capacity vs. Measured Impact by Program Type



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