Date of Hearing: July 16, 2025

ASSEMBLY COMMITTEE ON UTILITIES AND ENERGY
Cottie Petrie-Norris, Chair
SB 541 (Becker) – As Amended June 26, 2025

SENATE VOTE: 27-10

SUBJECT: Electricity: load shifting: distributed resources

SUMMARY: Requires the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to coordinate and implement strategies that increase load-shifting capacity, improve grid efficiency, and align distribution system planning with statewide energy goals. The CEC must allocate load-shifting targets to retail electricity suppliers, standardize measurement methods, identify implementation barriers, and determine the value of demand reduction by time and location. The CPUC must ensure large utilities use distributed energy resources to avoid costly infrastructure investments, share detailed grid data, implement incentive programs, and balance third-party participation with utility-led initiatives in load flexibility markets.

Specifically, **this bill**:

1) Requires the CEC, as part of each Integrated Energy Policy Report (IEPR), to divide the load shifting needed to reach the load-shifting goal required by Public Resources Code §25302, including biennial adjustments to the goal, to each retail supplier, excluding load shifting provided by emergency programs.

2) Requires the CEC, on or before July 1, 2028, and biennially thereafter, to evaluate and publish the amount of load shifting that each retail supplier achieved in the prior calendar year, and the amount of load shifting that each retail supplier is expected to achieve in future years, in comparison to the load shifting allocated to the retail supplier.

3) Requires the CEC to establish standards for estimating the amount of load shifting that has been, or will be, achieved by each type of load flexibility effort that retail suppliers undertake.

4) Requires the CEC, in consultation with the CPUC and CAISO, to identify and evaluate barriers to effectively implement load-shifting strategies and to establish a location-based avoided cost metric that estimates the value of demand reduction at different times and locations.

5) Defines "retail seller" to mean an electrical corporation, community choice aggregator (CCA), electric service provider (ESP), or local electric publicly owned utility (POU) and excludes an electrical corporation with 60,000 or fewer customer accounts or a retail supplier with an annual electrical demand of less than 1,000 gigawatt-hours (GWh).

6) Requires the CPUC On or before January 1, 2028 to develop a strategy to leverage distributed resources and load-shifting to increase the utilization of existing distribution and transmission infrastructure, increase the effective load-hosting capacity of existing

distribution and transmission infrastructure, provide bridging solutions to enable faster energization of new loads, and reduce the total distribution infrastructure investment required to meet long-term electricity load growth.

7) Requires the CPUC to mandate that each large electrical corporation, as part of their integration capacity analysis data or a successor policy, to make data available to the public that quantifies the potential for increased utilization of segments of its distribution grid by reducing peak load, including all of the following:

    a) A capacity utilization metric that measures the total energy delivered over a distribution segment during a period of time divided by the maximum energy that could have been delivered according to that distribution segment's maximum capacity.

    b) An off-peak load-hosting capacity metric that estimates the capacity of a distribution segment to support new loads outside of the 1 percent of hours with the highest peak load annually for that distribution segment, or data providing a similar quantification of off-peak capacity, as determined by the commission.

    c) The location and boundaries of constrained distribution areas with sufficient detail to allow third parties to identify customer locations where distributed resources could benefit the constrained distribution area.

8) Requires the CPUC to direct each large electrical corporation to implement programs, rate designs, or other incentives to encourage the development of load-shifting capacity or other peak demand reduction in constrained distribution areas, prioritizing the following goals:

    a) Improving capacity utilization and expanding the effective capacity of the constrained distribution area before specific electrical grid upgrade needs have been identified;

    b) Establishing an efficient process for large electrical corporations to acquire load-shifting capacity in a constrained distribution area.

    c) Accommodating the need for locational and temporal specificity while not creating undue complexity in implementation.

    d) Providing adequate incentives and a sufficiently long minimum contract period for the use and compensation of distributed resources to encourage investment.

    e) Establishing a customer consent-based process for up-front and ongoing access to customer data that is secure, consistent, not overly burdensome, and sufficient to identify eligible sites and operate in response to dispatch or economic signals.

f) Allowing participation by all customer classes and by both bundled and unbundled customers.

9) Requires the CPUC to ensure that programs operated by, or investments made by, large electrical corporations for load-shifting capacity do not interfere with the ability of third parties to develop load-shifting capacity that can be offered to other load-serving entities (LSEs) or to wholesale energy markets.

10) Requires the CPUC to consider how, and under what conditions, the same distributed resources can provide load flexibility for, and be compensated for, meeting both distribution grid needs and load modification or resource adequacy needs. This includes doing the following:

a) Authorize large electrical corporations to make investments in load-shifting capacity in a constrained distribution area that include the ability for the large electrical corporation to control the timing of the use of the load-shifting capacity

b) Authorize large electrical corporations to develop tariffs or fee structures to charge a large new load seeking energization for the cost of acquiring load-shifting capacity or other peak load reductions from other customers in order to allow or accelerate the energization of that large new load.

11) Requires the CPUC to ensure that the large electrical corporation has made reasonable efforts to increase cost-effective load shifting or other types of peak demand reduction in order to expand the effective capacity and increase the utilization of that segment of the distribution grid, before determining that an investment by a large electrical corporation to increase distribution system capacity is just and reasonable.

12) Requires the CPUC to mandate each large electrical corporation to provide relevant distribution planning data to the CEC, and to consult with the CEC to support alignment between distribution-level planning and the CEC's systemwide forecasting and planning.

EXISTING LAW:

1) Requires that all rates for any service or product charged by an electrical corporation be just and reasonable. (Public Utilities Code § 451)

2) Requires the CPUC to consider the role of existing renewable generation, grid operational efficiencies, energy storage, and distributed energy resources, including energy efficiency, in helping to ensure each load-serving entity meets energy needs and reliability needs in hours to encompass the hour of peak demand of electricity. (Public Utilities Code § 454.52(a)(3))

3) Requires each customer with distributed energy resources (DERs), as specified, to participate in real-time metering and pricing programs; and requires the CPUC to adopt a

real-time pricing tariff by December 31, 2001, to serve these customers. (Public Utilities Code § 353.3)

4) Permits IOUs, with approval of the CPUC, to offer residential customers the option of receiving electric service pursuant to "time-variant pricing," which includes time-of-use rates (TOU), critical peak-pricing, and real-time pricing. Beginning in 2018, an IOU can employ default TOU pricing as long as the customer is provided with a rate comparison for one year of all billing options (commonly referred to as shadow-billing) and associated customer education. Subsequently, the customer must be guaranteed for one year that the total amount paid for electric service will not exceed the amount that would have been due under the customer's previous rate schedule (commonly referred to as bill protection). (Public Utilities Code § 745)

5) Requires the governing board of a local publicly owned electric utility to consider the role of existing renewable generation, grid operational efficiencies, energy storage, and distributed energy resources, including energy efficiency, in helping to ensure each utility meets energy needs and reliability needs in hours to encompass the hour of peak demand of electricity. (Public Utilities Code § 9621)

6) Mandates the California Air Resources Board (CARB), in consultation with the CEC and the CPUC, to require battery electric vehicles to be bidirectional-capable, allowing EVs to support the grid. (Health Safety Code § 44269)

7) Directed the CEC to establish a statewide goal for load shifting and to adjust the goal in each biennial integrated energy policy report (IEPR). (Public Resources Code § 25302.7)

8) Allows funds from the safe drinking water, wildfire prevention, drought preparedness and clean air bond to be spent on zero-emissions distributed energy backup assets, virtual power plants, and demand side grid support. (Public Resources Code § 94530)

FISCAL EFFECT: According to the Senate Appropriations Committee, ongoing costs likely in the hundreds of thousands of dollars annually for the CEC (Energy Resources Program Account [ERPA] or other fund source) and the CPUC (ratepayer funds) to the implement the provisions of this bill.

CONSUMER COST IMPACTS: Unknown

BACKGROUND:

SB 846 (Dodd, Chapter 239, Statutes of 2022) Load Shift Goal – In May 2023, the CEC issued the Senate Bill 846 Load-Shift Goal Report. The CEC developed a statewide load-shift goal of 7,000 megawatts (MW) for 2030. According to the report, CEC staff analyzed the statewide load-shift potential using the following methodological steps:

1) Develop hourly gross load estimates using annual consumption forecasts from the Integrated Energy Policy Report (IEPR) and hourly load shapes provided by the Lawrence Berkeley National Lab (LBNL) Load model from the LBNL Potential Study.

2) Develop hourly system net load estimates and identify net peak period from the LBNL Potential Study and CAISO data.

3) Develop potential DR impacts for net peak reduction within two categories: dynamic pricing and event-based DR.

The report estimated that, as of 2022, there was an estimated 3,100-3,600 MW of load shift currently in the state. In order to reach the 2030 goal, the CEC identified three load shift interventions. First intervention is load-modifying demand flexibility resource potential (3,000 MW). The most common type of load modifying intervention is time of use rates. A second load shift intervention is resource planning and procurement of load flexibility resources. This includes supply-side demand response that participates in the CAISO as economic or reliability demand response. The final intervention is incremental and emergency load-flexibility resource programs, which increase resource availability during extreme events. This includes the Emergency Load Reduction Program and the Demand Side Grid Support program which can be activated during emergency grid events. The report also includes 18 policy recommendations to support deployment of the three categories of interventions.

Within the report, the CEC cautions that this is an aspirational statewide goal based on economic potential. The report states:

> *Further analysis is needed to determine the cost-effectiveness of specific load flexibility resources and programs. The proposed goal is not intended to suggest that the state should pursue these targets without the evaluation of the cost-effectiveness of specific resources or programs that would contribute to the goal… The load-shift goal is set at the statewide level and does not intend to set subgoals for specific program types, sectors, or jurisdictions.* [1]

Distribution Investment Deferral Framework and Incentivizing DERs – In 2018, the CPUC established the Distribution Investment Deferral Framework (DIDF). The goal of DIDF was to for IOUs to identify low-cost opportunities for Distributed Energy Resources (DERs) to defer traditional capital investments, and for the IOUs to pursue an open market solicitation for DER solutions. The DIDF process has focused on non-wired alternatives to distribution investments at specific grid locations. The CPUC adopted various metrics for identifying and selecting these opportunities, including metrics for cost-effectiveness, forecast certainty, and market assessment. The DIDF process also provided information on the actual cost of distribution system upgrades and the process of distribution planning to the CPUC and the wider public.

Although it has been revised several times, DIDF has not done well in deferring traditional wires investments. It may be that DIDF is structurally flawed, however, the CPUC has assessed that consistent lackluster results show that it can be difficult and expensive to defer investments through DERs. The CPUC has reported that non-wires alternatives can fail for many reasons including changing project needs and locations, barriers to DER deployment such as interconnection delays, uncertainty in the contracting process, and developer failure. DIDF has been considered ineffective at increasing DER implementation, but has provided transparency into IOU distribution planning.[2]

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[1] CEC, "Commission Report on the SB 846 Load Shift Goal", May 26, 2023.
[2] CPUC, "Staff Proposal for the High DER Proceeding," April 5, 2024

COMMENTS:

1) *Author's Statement.* According to the author: "We need to improve electricity affordability while also providing power faster to support new housing, EV chargers, data centers, and other economic growth. The good news is that our electricity system has a lot of spare capacity – 99% of the time. It is only a few peak hours, less than 100 per year, where we struggle to meet demand. A recent study from Duke estimated that CA has almost 6000 MW of capacity for new load outside of the top 1% of hours. That's enough to power 3M homes or 30 massive new data centers. If we can reduce load during those peak hours, by shifting some demand to other times, then we can unlock all that spare capacity to support housing and EVs and data centers much faster, and at much lower cost, than building more capacity to serve even higher peaks. SB 541 attempts to create accountability for our electricity suppliers to seek cost-effective load shifting by having the CEC divide its 7000 MW load shift goal among suppliers and track progress. It also directs the PUC to create more transparency about where load-shifting would help reduce constraints in the distribution system and to require and enable IOUs to develop load flexibility in constrained distribution areas more proactively so that we can support new loads faster and get more out of the poles and wires we've already paid for."

2) *Purpose of the Bill.* As mandated by the legislature, the CEC has identified a load-shift goal of 7000 MW and has proposed potential strategies to reach this load-shift goal. The CPUC, the CEC and CAISO have worked to promote distributed energy resources for the purposes of achieving this load-shift and to defer grid investment. However, programs such as DIDF, as described above, have neither shown the investment needed to meet the CEC load shift goal by 2030 nor deferred grid investment. The goal of the bill is to incentivize greater investment by energy retailers toward achieving the state's load-shift goal by increasing transparency in current load shifting programs. In addition, the bill mandates the development of a strategy to incentivize using distributed resources to increase the utilization of exiting distribution and transmission infrastructure.

3) *Dividing the CEC's load shift goal across retail suppliers.* When generating the 2022 load-shift goal, as mandated in SB 846, the CEC explicitly noted that the goal is not intended to set subgoals for specific program types, sectors, or jurisdictions. Despite this direction from the CEC, this bill mandates the CEC to divide the load-shift goal across retail suppliers. However, the bill also states that subdivision is not intended to impose a binding obligation or otherwise mandate the procurement of load-shifting technologies by the retail suppliers. These two requirements in the bill – that 1) the CEC divide the load-shift goal across the various LSEs while 2) not imposing any new procurement obligation on them – seem to internally conflict. How are the LSEs meant to meet their individualized goals without establishing new programs or procurement? What is the function of the CEC assigning targets to each LSE if those targets aren't intended to be reached? At minimum, the expectation on LSEs from these provisions is confusing, and has led to many utilities, especially the POUs, to oppose this measure. *To clarify the desire for increased transparency but also make sure that the bill does not mandate procurement, the committee recommends striking the language that divides the load-shift*

goal. Rather, the bill will retain the requirement that the CEC estimate each retail supplier's load-shifting potential, and biennially report how much load shifting the suppliers have achieved relative to that potential.

4) *Cost Effectiveness.* This bill asserts the foundational premise that demand response technologies and tools are wholly beneficial. A reflection of this perspective is noted in the sixth finding, "load flexibility to reduce peak load is a cost-saving opportunity." While demand response tools are often among the fastest and most affordable to deploy – and can help maximize grid efficiency and give customers greater control over their energy use – they often face practical challenges that limit their cost-effectiveness and overall value to the grid. The current language of this bill misses opportunities to provide this perspective, and instead drives LSEs toward achieving the load-shift goal without consideration of cost-effectiveness or feasibility. The author has noted this is not their intent. *To address these concerns, the committee recommends directing the CEC to analyze the cost-effectiveness of specific load flexibility programs and tools in the next IEPR; to include consideration of cost-effectiveness of these tools and programs as well as specific limitations for their deployment for each LSE when the CEC determines the LSE's load-shifting potential in Section 2 (PRC § 25302.7 (b)(1)); and to have the CPUC consider cost effectiveness in determining their load-shifting strategy in Section 3 (PUC § 769.1).*

5) *Not Repeating Past Mistakes.* California is experiencing a transformational time in how electricity is generated, distributed and consumed. One of the key factors underlying this change is the emphasis on demand response programs and new and emerging load-shifting strategies. California's utilities have effectively used demand response technologies – smart thermostats, automated control, aggregation platforms, and virtual power plants – to actively manage grid demand, prevent outages, and integrate renewable energy. For instance, Valley Clean Energy's AgFIT (Agricultural Flexible Irrigation Technology) pilot – launched in May 2022 – helps farmers automate irrigation and shift energy use to low-cost, clean-energy hours.[3] In partnership with Polaris Energy Services and TeMix, the program offers customer incentives of up to $150 per horsepower unit to install irrigation automation alongside transparent pricing, with electricity costs published a week ahead so farmers can schedule irrigation during cheaper, grid-friendly times. VCE reports participants typically save 10–15% on their electricity bills, shift about 40% of their load away from evening grid peaks, and reduce costs by roughly 30% while helping grid reliability and supporting renewable integration.[4]

   However, such co-beneficial outcomes are not always guaranteed. As noted above, the IOUs efforts undertaking the DIDF have not done well, and as a result that program is currently suspended at the CPUC. The IOUs have stated concern that Section 3 of this bill, requiring the CPUC to develop a strategy to increase DER utilization, is a resurrection of the failed DIDF. *Given this context, the committee recommends amendments that specify in the legislative intent to apply lessons-learned from past DER*

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[3] https://valleycleanenergy.org/programs/a-flexible-irrigation-pilot-program-for-agriculture/
[4] https://valleycleanenergy.org/news/valley-clean-energy-launches-an-innovative-program-for-agricultural-customers-to-reduce-grid-stress-and-save-farmers-money

efforts; that the CPUC's strategy in Section 3 (PUC § 769.1) is centered around reducing total distribution infrastructure investment (rather than to leverage DERs); and to allow IOUs to rely on the load-shifting capacity as part of their distribution system planning so long as the IOU is capable of controlling the timing of the resource and the resources is feasible, cost-effective, and reliable.

6) *Additional Amendments.* The committee and author have agreed to a number of clarifying and/or technical amendments to help address the themes throughout the text of the measure of cost-effectiveness, lessons-learned from past programs, and having programs serve overall distribution grid needs. *The committee recommends adoption of all of these amendments*.

7) *Related Legislation*

AB 44 (Schultz) requires the CEC to create and share methods for adjusting LSEs' energy demand forecasts. These methods will be based on the use of technologies and programs that reliably reduce or shift electricity use, as agreed upon by the CEC, the CPUC, and the CAISO. Status: *Set for hearing* in the Senate Committee on Energy, Utilities and Communications on July 15, 2025.

AB 740 (Harabedian) requires the California Energy Commission (CEC), on or before November 1, 2026, to adopt a virtual power plant (VPP) deployment plan. Status: *Set for hearing* in the Senate Committee on Energy, Utilities and Communications on July 15, 2025.

AB 1117 (Schultz) creates optional, dynamic electricity rates for large investor-owned utility (IOU) customers. These rates would change based on real-time conditions of the electricity grid and market prices. Participation in these dynamic pricing plans would be voluntary. The bill also aims to ensure that adopting these new rates doesn't unfairly shift costs between different customer groups. Status: *Set for hearing* in the Senate Committee on Energy, Utilities and Communications on July 15, 2025.

8) *Prior Legislation*

SB 1305 (Stern, 2024) would require the CPUC, in coordination with the State Energy Resources Conservation and Development Commission and the Independent System Operator, to take begin a proceeding to determine targets for virtual power plants procurement and require IOUs to report on their progress to meeting these targets. Status: Held in the Senate Committee on Energy, Utility and Communications.

SB 59 (Skinner) authorized CARB, in consultation with the CEC and the CPUC, to require BEVs to be bidirectional-capable if it determines that there is a sufficiently compelling benefit to the BEV operator and the electrical grid. Status: Chapter 765, Statutes of 2024.

AB 205 (Ting) authorized funding and changes in many energy focused programs, including the DSGS Program and appropriated $200 million to the CEC to run the Program. Status: Chapter 61, Statues of 2022.

SB 846 (Dodd) among its many provisions, required the CEC to adopt a load shifting goal to reduce net peak electrical demand. Status: Chapter 239, Statutes of 2022.

SB 49 (Skinner) expands the California Energy Commission's (CEC) authority to develop standards for appliances to facilitate the deployment of flexible demand technologies. Status: Chapter 697, Statutes of 2019.

AB 3001 (Bonta, 2018), among its provisions, requires the CPUC to offer optional residential and commercial rates that encourages the deployment of flexible electric loads. Status: Died – Assembly Committee on Natural Resources.

AB 327 (Perea), among its many provisions, restructures the rate design for residential electric customers. Status: Chapter 611, Statutes of 2013.

REGISTERED SUPPORT / OPPOSITION:

Support

Advanced Energy United
California Efficiency + Demand Management Council
California Energy Storage Alliance
California Solar & Storage Association
California Solar and Storage Association
Carbon Free Palo Alto
Carbon Free Silicon Valley
Climate Center; the
Coalition for Community Solar Access
Deploy Action
Microgrid Resources Coalition
National Resources Defense Council
Nexamp
Rewiring America

Support If Amended

Ava Community Energy Authority
Coalition of California Utility Employees

Oppose

California Municipal Utilities Association (CMUA)
California Special Districts Association
Imperial Irrigation District
Southern California Public Power Authority (SCPPA)

Oppose Unless Amended

Burbank/burbank Redevelopment Agency; City of
California Community Choice Association

Edison International and Affiliates, Including Southern California Edison
Marin Clean Energy (MCE)
Pacific Gas and Electric Company
San Diego Gas & Electric

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