Date of Hearing: April 23, 2025

ASSEMBLY COMMITTEE ON UTILITIES AND ENERGY
Cottie Petrie-Norris, Chair
AB 44 (Schultz) – As Amended April 7, 2025

SUBJECT: Energy: electrical demand forecasts

SUMMARY: Requires by December 1, 2026, the California Energy Commission (CEC) to create and share methods for adjusting load-serving entities' (LSEs) energy demand forecasts (i.e., "load modification protocols"). 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 California Public Utilities Commission (CPUC), and the California Independent System Operator (CAISO).

EXISTING LAW:

1) Requires the CEC to adopt a goal for load shifting by June 1, 2023, to reduce net peak electrical demand, and requires biennial updates to the targets. Requires the CEC to make recommendations to increase load shifting that does not increase greenhouse gas (GHG) emissions or increase electric rates. (Public Resources Code § 25302.7)

2) Requires the CEC to adopt the Integrated Energy Policy Report (IEPR) every two years, which must contain an overview of major energy trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment. (Public Resources Code §§ 25300-25327)

3) Defines "load-serving entities" as investor-owned utilities (IOUs), electric service providers (ESPs), and community choice aggregators (CCAs). (Public Utilities Code § 380 (k))

4) Requires the CPUC to work with the CAISO to establish resource adequacy (RA) requirements for LSEs. Existing law specifies the criteria the CPUC must consider when establishing RA requirements and specifies that an electrical corporation's reasonable costs for meeting RA are recoverable from customers through non-bypassable charges. (Public Utilities Code § 380)

5) Requires the CEC to adopt standards for appliances to facilitate the deployment of flexible demand technologies. These regulations may include labeling provisions to promote the use of appliances with flexible demand capabilities. The flexible demand appliance standards must be based on the ability of the appliance's functions to be scheduled, shifted, or curtailed to reduce GHG emissions associated with electricity generation. The standards shall become effective no sooner than one year after the date of their adoption or updating. (Public Resources Code § 25402(f))

FISCAL EFFECT: Unknown. This bill is keyed fiscal, and will be referred to the Assembly Committee on Appropriations for its review. A similar measure (AB 2891, Friedman, 2024) was introduced last year and reviewed by the Appropriations Committee. The CEC estimated approximately $923,000 annually to implement the bill; although the Appropriations staff noted the lack of clarity from the CEC as to why they needed those resources and associated positions on an annual basis, when the bill was specific to a one-time protocol.

CONSUMER COST IMPACTS: Unknown. This bill enables new technologies to potentially reduce a utility's obligations under an existing compliance program (RA). The cost for program compliance is paid through electric rates, so reductions to compliance requirements may reduce cost. However, that is only if the cost of the new technologies is less than the cost to comply. The bill acknowledges this uncertainty by directing the CEC to use available non-ratepayer funding to test these new technologies.

BACKGROUND:

Load Modifiers, Demand Response, and Distributed Energy Resources (DER) – In the context of electric service, "load," in a very general sense, is anything that uses electricity. LSEs, therefore, are the organizations that provide the electricity to meet the electrical demand created by load. These organizations include publicly owned utilities (POUs) and investor-owned utilities (IOUs), as well as other utility-like entities that supply electricity to customers.

DER is a catch-all term used for a variety of generation, storage, or load modifying resources that are usually connected to the utility distribution system. DERs include both generation technologies that reduce customer load when consumed on-site (e.g., customer-sited rooftop solar) and load modifying technologies that reduce customer load by actively shifting or reducing customer energy usage (e.g., demand response programs). In other words, DERs can affect either the supply or demand of energy, but are usually located behind the customer meter; and thus to the larger grid may be viewed solely as modifying customer load.

DERs have traditionally been "visible" to CAISO as load reduction resources, where their deployment reduces the overall system demand from an LSE's territory. For example, behind-the-meter (BTM) rooftop solar reducing the need for alternative resources during the sunniest parts of the day and year. As growth in DERs continues, these resources seek greater participation in the CAISO market by not only modifying load but also seeking to export their power—often in aggregate—to be compensated for that export. The CAISO tariff does allow aggregations of DERs to participate in its markets.[1] However, CAISO's most recent deliverability assessment for distributed generation showed scant amounts of DER selected in LSE resource portfolios, and thus hardly any was studied.[2] The recently established Emergency Load Reduction Program at the CPUC creates a test case for some of these DER challenges, by compensating BTM generation for exported energy under emergency conditions.[3]

Resource Adequacy (RA) – The RA process, overseen by the CPUC and CAISO, is designed to identify resources needed to ensure reliability. Following the California energy crisis of 2000-01,

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[1] ISO Tariff updated for Distributed energy resource provider, http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx
[2] CAISO, "2022-2023 DG Deliverability Assessment Results*" Resource Adequacy Deliverability for Distributed Generation*, February 17, 2023. http://www.caiso.com/Documents/2022-2023-Deliverability-Distributed-Generation-Study-Results-Report.pdf
[3] Customers with DERs that can generate energy (BTM solar+storage, EVs, cogeneration, etc) that have permission to export are eligible to participate. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program#:~:text=What%20is%20the%20Emergency%20Load,periods%20of%20electrical%20grid%20emergencies

the California Legislature enacted AB 380 (Nunez, Chapter 367, Statutes of 2005) to prevent future incidents of widespread blackouts and rolling brownouts due to lack of electricity. This statute established the RA program at the CPUC, which must work in consultation with the CAISO to establish RA requirements for all LSEs. The current RA program consists of system, local, and flexible requirements for each month of a compliance year. System requirements are determined for each LSE based on the CEC's integrated energy policy report (IEPR) electricity forecast plus a 15% planning reserve margin.[4] Local requirements are determined based on an annual CAISO study using a 1-10 (once in ten years) weather year and an N-1-1 contingency.[5] Flexible requirements are based on an annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably. In October, LSEs must demonstrate that they have procured 90% of their system RA obligations for the five summer months (May-September) of the following year, as well as 100% of their local requirements, and 90% of their flexible requirements for each month of the coming compliance year. There is an additional monthly reporting requirement for RA, where LSEs must demonstrate they have procured 100% of their monthly system and flexible RA obligation.

The RA market has experienced significant constraint recently, largely driven by resource retirements across the western U.S. as well as extreme weather events causing California energy agencies to increase RA obligations for LSEs, such as the PRM adjusting from 15% to an "effective" 20-22.5% for the three large IOUs for summers 2022 and 2023.[6] These changes have led to a market rush, practically at any cost, to buy resources needed to meet RA obligations for the next few summers. Energy sellers have seemingly taken note. As shown in Figures 1 and 2 below, both system and local RA prices have increased significantly over the last few years, and were projected to be even higher for the coming summers. Anecdotal reports for this coming summer, however, suggest the market may be cooling with RA prices trending down.

Figure 1: Weighted Average Price of System RA, 2017-2022 ($/kW-month)[7]

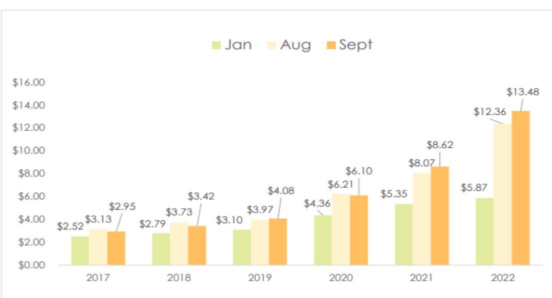
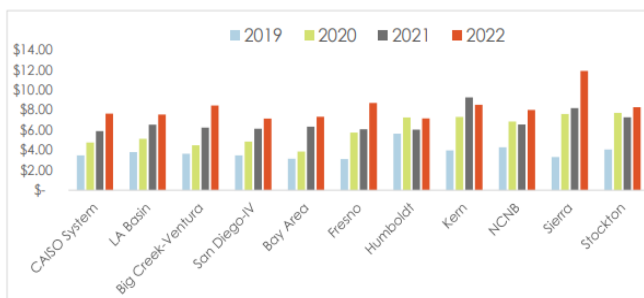


Figure 2: Weighted Average Prices for Local RA, 2019-2022 ($/kW-month)[8]



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[4] The CPUC has recently adopted changes to RA, including increasing the planning reserve margin from 15% to 17.5% and in some cases to 20-22%.
[5] N-1-1 Contingency: A sequence of events consisting of the initial loss of a single generator or transmission component (Primary Contingency), followed by system adjustments, followed by another loss of a single generator, or transmission component (Secondary Contingency).
[6] D. 21-12-015, CPUC, *Phase 2 Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, R. 20-11-003, December 2, 2021.
[7] Figure 4, pg. 30, CPUC, *2022 Resource Adequacy Report*, May 2024; https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf
[8] Figure 5, pg. 31, *2022 Resource Adequacy Report*, *Ibid.*

These RA requirements, matched with utilities' desire to meet them and the recent, lucrative prices for RA, are critical factors in determining the market values of individual resources, to the point that the expectation that a resource would not be counted toward RA may severely disincentivize its development.

The IEPR (demand forecast) – Alongside other planning guidance focusing on energy generation needs in both the mid- and long-term, the CEC conducts an IEPR to forecast all aspects of energy industry supply, production, transportation, delivery, distribution, demand, and pricing. The demand forecast the CEC adopts in its IEPR informs the generation planning processes at the CPUC, as the supply provided by the CPUC analysis (IRP and RA) must match the customer demand (IEPR) provided by the CEC.

The CEC is responsible for producing both statewide and LSE-specific demand forecasts to inform both policy and grid operations. LSEs annually submit their own year ahead peak demand forecast to the CEC, including any relevant DER load modifiers that lower their peak demand. The CEC team reviews LSE forecasts, compares them to their own forecasts, and makes adjustments to resolve discrepancies between the two. The load reductions from a LSE program are then incorporated into the CEC's final adjusted forecast. The CPUC uses the CEC's forecasts to determine individual LSE RA obligations.

As a consequence, LSEs have – in effect – two venues to meet or adjust their RA requirements, utilizing either supply- or demand-side resources. The supply-side involves generation resources that are shown to the CPUC during the LSE's annual and monthly RA reports. The demand-side involves load modifying resources that are annually shown to the CEC as a reduction in the LSE's peak demand forecast, which the CEC then uses to adjust its final demand forecast of that LSE – and thus reducing that LSE's RA obligation.

Statewide Load-Shift Goal – In 2022, the Legislature required the CEC to develop a statewide goal for load shifting to reduce net peak electrical demand (SB 846, Dodd, Chapter 239, Statutes of 2022). In May 2023, the CEC published their final report where they established the statewide goal of 7 gigawatts (GW) of load-shift by 2030, estimating that roughly 3.1-3.6 GWs of load was shifted in 2022.[9] The CEC noted their view that "the proposed target is aspirational but achievable with robust policy support,"[10] and made 18 policy recommendations to consider in order to reach the goal. Among those recommendations were policies included in this measure, including allocating funding for the CEC to supplement DR,[11] reforming availability rules and RA resource requirements, [12] and promoting load-modifying program development and measurement, including reducing RA requirements on LSEs with these programs.[13]

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[9] Pg. 3, Table ES-1; CEC, *Senate Bill 846 Load-Shift Goal Report*, May 2023, CEC-200-2023-008; file:///C:/Users/shybutla/Downloads/TN250357_20230526T142745_SB%20846%20Load%20Shift%20Goal%20Commission%20Report%20(4).pdf
[10] Pg. 3, CEC *Load-Shift Goal Report*, 2023, *Ibid.*
[11] Recommendation 11; pg. 6; CEC *Load-Shift Goal Report*, 2023, *Ibid.*
[12] Recommendation 12; pg. 6; CEC *Load-Shift Goal Report*, 2023, *Ibid.*
[13] Recommendation 8; pg. 6; CEC *Load-Shift Goal Report*, 2023, *Ibid.*

COMMENTS:

1) *Author's Statement.* According to the author, "AB 44 would enhance a tool that retail providers can use to increase grid reliability and better manage energy procurement costs for consumers, augmenting downward pressure on rates for all customers. By enhancing transparency in the process by which load-modifying technologies could shift or reduce the state's resource adequacy needs during the most expensive hours, this bill would increase uptake in this cost-saving method. Distributed energy providers would have more clarity on what functionalities they must offer retail providers to produce cost-saving value, retail providers would have assurances would reduce the cost of serving customers, and energy planning agencies would have greater confidence in the reliability performance of aggregated distributed energy resources."

2) *Chicken or the Egg?* As noted above, the state's RA program exists to ensure enough resources are available each month to serve customer demand. Changing either the volume of resources supplying the market or the volume of customer demand will impact the needed RA. The RA market has experienced significant constraint recently, largely driven by resource retirements across the western U.S. as well as extreme weather events and ever-increasing RA obligations for the state's LSEs.[14] These actions have affected the supply-side of the RA market.

   For the past decade, demand has been relatively flat in California. However, the demand-side is expected to change over the coming decades due to increased electrification of transportation and housing, as well as climate events such as heatwaves. In fact, one of the contributing factors of recent summer shortfalls was a mismatch between the forecasted IEPR demand and the actual demand.[15]

   As a result, the state has established a number load reduction programs over the past few years to help reduce customer demand during emergencies.[16] However, this bill's author suggests these demand response programs have done little to reduce the pressures on the supply-side, and thus alleviate energy affordability. The author offers the CPUC's Emergency Load Reduction Program (ELRP) as an example, which compensates participants at the premium rate of $1 per kilowatt-hour (kWh).[17] This compensation is double that of PG&E's default residential rate, at $0.51 per kWh for baseline customers;[18] in other words, it is quite an expensive program. In establishing the program, the CPUC explicitly excluded the ELRP resources from being counted toward system RA. [19] Instead, LSEs must procure the same amount of RA as would be needed if the ELRP didn't exist, essentially erasing any savings to the supply-side procurement

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[14] D. 21-12-015, CPUC, *Phase 2 Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, R. 20-11-003, December 2, 2021.
[15] Pg. 39-40, CAISO, *FINAL Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*; January 13, 2021.
[16] CPUC Decision D.21-03-056 Attachment Page 22 at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821668.PDF
[17] *Ibid.* committed $201.7 million in ratepayer funds. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M373/K973/373973362.PDF
[18] See PG&E residential TOU rate schedule comparison at https://www.pge.com/content/dam/pge/docs/account/rate-plans/residential-electric-rate-plan-pricing.pdf
[19] See page 2 of Attachment to D.21-12-015 at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821668.PDF

obligations of the LSEs. The CPUC notes its view of the ELRP as "an insurance policy made available during emergency conditions to supplement the reliability already provided by the RA program,"[20] rather than a demand-side resource meant to contribute fully to the RA program. In this way, ELRP treats aggregated load modification resources in the traditional way: as emergency resources. This bill seeks to instead make clear the obligations of an aggregator if an LSE is to proactively use these resources as a demand modifier.

3) *Need for bill.* As noted above, there exists a process at the CEC to reduce RA procurement obligations by utilizing demand-side resources. However, the author notes this process has seen limited participation by LSEs due to a lag between deploying technologies and when the LSE's demand forecast is reduced. Supporters for this bill note this creates a financial risk for LSEs, where they have to purchase supply-side RA resources to cover a demand that is actually being reduced by demand-side resources; in simple terms, the reporting between the IEPR and the RA programs is delayed, leading to increased compliance cost.

   This bill requires the CEC to adopt a set of requirements to enable LSEs to use these demand-side resources to reduce their IEPR demand forecast, and subsequently their RA obligations. However, caution may be in order, as these demand-side resources can vary greatly in their design – from virtual power plants to aggregated residential thermostats – and vary in their visibility to the state agencies and CAISO market. It is essential for resources counted as RA to show up when expected. This bill seems to recognize this caution by not mandating adoption of these technologies, but rather enabling state agencies and the CAISO to set all the requirements and protocols and requiring any deployed technology to be deemed effective and reliable by the state agencies and CAISO.

   The actions in this measure seem aligned with recommendations the CEC adopted as part of its 2023 *Load-Shift Goal Report*, calling for 7GW of load-shifting by 2030, as noted above.[21]

4) *Related Legislation.*

   AB 740 (Harabedian, 2025) requires the CEC, on or before November 1, 2026, to adopt a strategy to enable virtual power plants to be deployed at scale, as specified. Status: Set for hearing in this committee on April 23, 2025.

   AB 1117 (Schultz, 2025) creates optional, dynamic electricity rates for IOU customers. The bill also aims to ensure that adopting these new rates doesn't unfairly shift costs between different customer groups. Status: In the Assembly Committee on Appropriations after passage in this committee on April 2, 2025 on a 14-0-4 vote.

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[20] Pg. 20, D. 21-03-056

[21] CEC, *Senate Bill 846 Load-Shift Goal Report*, May 2023, CEC-200-2023-008; file:///C:/Users/shybutla/Downloads/TN250357_20230526T142745_SB%20846%20Load%20Shift%20Goal%20Commission%20Report%20(4).pdf

SB 541 (Becker, 2025) requires the CEC, as part of each integrated energy policy report, to identify incremental load shifting targets to meet the statewide load-shifting goal, including biennial adjustments to the goal. Additionally requires all retail suppliers, as defined, to provide rate information to the CEC's Market-Informed Demand Automation Server in order to provide third-party devices with access to real-time rate information; and requires the CPUC, on or before January 1, 2028, to require all load-serving entities to offer optional dynamic pricing tariffs, as specified, and the governing boards of each POU to consider offering dynamic pricing tariffs, as specified. Status: In Senate Committee on Energy, Utilities, and Communications where it is set for a hearing on April 21, 2025.

5) *Prior Legislation.*

AB 2891 (Friedman, 2024) largely similar to this measure, required the CEC to adopt technical requirements and load modification protocol – meaning a combination of capabilities and operational parameters to confidently reduce an LSE's electrical demand forecast for any specified hour or hours – to provide the option for an LSE to reduce or modify the LSE's electrical demand forecast.. Status: Died – Assembly Committee on Appropriations.

AB 1623 (Muratsuchi, 2023) required the CPUC, on or before June 30, 2024, and as part of a new or existing proceeding, to revise the net qualifying capacity and effective flexible capacity methodologies for energy storage resources. Status: Died – Assembly Committee on Appropriations.

SB 846 (Dodd), among its many provisions, requires the CEC to adopt a goal for load shifting by June 1, 2023, to reduce net peak electrical demand, and requires biennial updates to the targets. Status: Chapter 239, Statutes of 2022.

SB 1432 (Hueso, 2022) made changes to the RA program and required the CPUC to develop a pilot program for aggregated customer-sited DER to assess the value of energy exports from those resources for purposes of fulfilling the requirements of the RA program. Status: Vetoed by the Governor, who cited "threshold issues" needing to be addressed before DER could contribute reliably to RA.

SB 49 (Skinner) expanded the CEC's appliance energy efficiency authority by requiring the CEC develop standards for appliances to facilitate the deployment of flexible demand technologies. The standards must be based on the ability of an appliance's operations to be scheduled, shifted, or curtailed to reduce GHG emissions associated with electricity generation. Status: Chapter 697, Statutes of 2019.

REGISTERED SUPPORT / OPPOSITION:

Support

350 South Bay Los Angeles
350 Southland Legislative Alliance
Advanced Energy United
Ban Sup (single Use Plastic)
California Energy Storage Alliance

California Solar & Storage Association
Long Beach Alliance for Clean Energy
Mainspring Energy
NRG Energy
Sunrun
The Climate Center
The Climate Reality Project Orange County Chapter
The Climate Reality Project, Bay Area Chapter
The Climate Reality Project, California State Coalition
The Climate Reality Project, Los Angeles Chapter
The Climate Reality Project, Riverside County Chapter
The Climate Reality Project, Sacramento Chapter
The Climate Reality Project, San Diego Chapter
The Climate Reality Project, San Fernando Valley CA Chapter
Urban Ecology Project

Opposition

None on file.

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