Date of Hearing: March 18, 2026

ASSEMBLY COMMITTEE ON UTILITIES AND ENERGY
Cottie Petrie-Norris, Chair
AB 1787 (Schultz) – As Amended March 2, 2026

SUBJECT: Electrical corporations: rates: optional dynamic rate tariff

SUMMARY: Requires the California Public Utilities Commission (CPUC) to require large electrical corporations (IOUs) to offer an optional dynamic rate tariff to customers if the CPUC has approved upgrades to the IOU's smart meter infrastructure and related information management and billing systems on or after January 1, 2027. Specifically, **this bill**:

1) Requires that the CPUC ensure the optional dynamic rate tariff is consistent with the Federal Energy Regulatory Commission (FERC) transmission ratemaking authority and includes the following components:
   a. A time-varying distribution rate that reflects dynamic distribution grid constraints in the distribution service area, if determined by the CPUC to be feasible.
   b. A time-varying generation rate for bundled customers that reflects day-ahead hourly wholesale market conditions.
   c. Nonbypassable charges.

2) Mandates that the CPUC cannot approve the request for IOUs to recover costs for the smart meter upgrades unless the following conditions are met:
   a. Each customer required to pay for the costs associated with the smart meter upgrades has access to an optional dynamic rate tariff.
   b. The IOU provides customers with the ability to access data directly from the smart meter, if the technology includes wireless communications functionality.
   c. As applicable, the IOU provides customer usage data in an accurate and timely manner to customer's load serving entity (LSE).
   d. IOUs provide customers access to energy usage data, as it is generated, through a secure application program interface.
   e. IOUs must also allow customers to authorize qualified third-party service providers to have access to that data, and the CPUC shall ensure the IOUs do not favor their own customer program administrator.

3) Requires the CPUC to mitigate cost shifts between bundled and unbundled customers and between participating and nonparticipating customers by doing the following:
   a. IOUs must make the same time-varying transmission and distribution rates available to both bundled and unbundled customers in the same geographical area and ensure the rates are the same across similar levels of electrical demand.
   b. The CPUC must periodically evaluate and mitigate any cost shifting from the optional dynamic rate tariff by reviewing the following:
      i. Total number or percentage of participants across applicable customer segments, including bundled and unbundled customer segments.
      ii. Volume of energy sales for participating customers and nonparticipating customers on a time-differentiated basis.
      iii. Total revenue changes, the large electrical corporation's cost reductions associated with load shifts, and the estimated rate impacts on participating and nonparticipating customers.

iv. Any asymmetrical effect on vulnerable residential customers.

c. IOUs must track and manage separately any bundled customers participating in an energy subscription option and ensure the participating customer is responsible for the costs associated with the wholesale resources used to provide the energy subscription option.

4) Requires LSEs to be responsible for setting the generation rate options for participating customers based on wholesale electricity market conditions faced by the LSE.

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 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)

3) Requires the CPUC to ensure that rates are sufficient to enable IOUs to recover a just and reasonable amount of revenue from residential customers as a class, while observing the principle that electricity and gas services are necessities, for which a low, affordable rate is desirable and while observing the principle that conservation is desirable in order to maintain an affordable bill. (Public Utilities Code § 739)

4) Requires the CPUC to establish rates using cost allocation principles that fairly and reasonably assign to different customer classes the costs of providing service to those customer classes, consistent with the policies of affordability and conservation. (Public Utilities Code § 739.6)

5) Requires IOUs to offer default rates to residential customers with at least two usage tiers. (Public Utilities Code § 739.9)

6) 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. (Public Utilities Code § 745)

7) Requires the CPUC to report to the Legislature and Governor biennially on progress made toward modernizing the state's distribution and transmission grid, largely focused on connecting DERs. (Public Utilities Code § 913.6)

8) Declares it state policy to modernize the electrical transmission and distribution system with infrastructure that could be characterized as a smart grid, including consumer devices for metering and ones that provide consumers with timely information and control options. (Public Utilities Code § 8360)

9) Requires, by July 1, 2011, both electrical corporations and larger POUs[1] to develop a smart grid deployment plan. The electrical corporations must submit their plans to the CPUC for

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[1] Those with more than 100,000 service connections

approval, which must ensure the plan meets specified policy objectives and federal operability rules. (Public Utilities Code §§ 8362, 8364, 8369)

10) Requires the CPUC, in consultation with the California Energy Commission (CEC) and the California Independent System Operator (CAISO), to evaluate the impact of smart grid technology deployment on major initiatives and policies, including implementation of new advanced metering initiatives. (Public Utilities Code § 8366)

11) Prohibits a business from sharing with any third party a customer's electrical or natural gas usage data made available by advanced metering without first obtaining the express consent of the customer and conspicuously disclosing to whom the disclosure will be made and how the data will be used. (Civil Code § 1798.98, Public Utilities Code § 8380-8381)

12) Authorizes the Department of Energy to award $4 billion in grants ranging from $500,000 to $20 million for smart grid technology deployments and grants of $100,000 to $5 million for the deployment of grid monitoring devices. (federal Public Law 111-5, the American Recovery and Reinvestment Act (ARRA) of 2009)

13) Requires the National Institute of Standards and Technology to be the lead agency to develop standards and protocols for the smart grid, and creates a research, development, and demonstration program for smart grid technologies at the Department of Energy, among other provisions. (federal Public Law 110-140, the Energy Independence and Security Act of 2007)

FISCAL EFFECT: Unknown. This bill is keyed fiscal and will be referred to the Assembly Committee on Appropriations for its review. A similar bill – AB 1117 (Schultz, 2025) – required the CPUC to develop optional dynamic rate tariffs applicable to each large IOU, which the CPUC estimated would cost $466,000 annually, according to the Senate Committee on Appropriations.

BACKGROUND:

Smart Meters – Also known as advanced metering infrastructure (AMI), smart meters are a critical component of smart grids. Smart meters and associated smart grid technology allow utilities and customers to quickly monitor energy usage, manage the grid system more effectively, and better handle electricity from renewable sources like rooftop solar. Beyond the data-sharing benefits, smart meters also save utilities money on avoided meter operation costs and truck dispatch. The Sacramento Municipal Utility District (SMUD) saw over $8.6 million in savings in the first 13 months of smart meter deployment from reduction in manual meter readings and service calls alone.[2] Smart meters are also critical in achieving advanced rate design – such as dynamic, time-varying tariffs – which rely on the fast flow of customer usage data to be implementable. In other words, you can only manage what you can measure; and smart meters enable more granular measurement – and therefore management – of the electric system.

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[2] Pg. 54, Office of Electricity Delivery and Energy Reliability, US DOE, *Advanced metering Infrastructure and Customer Systems*, September 2016; https://gridmap.gridwise.org/wp-content/uploads/2024/07/AMI-Summary-Report_09-26-16.pdf

In 2009, as part of the American Recovery and Reinvestment Act (ARRA), the federal government awarded billions of dollars in grants for smart grid infrastructure, including smart meters. Tens of millions of those dollars flowed to California utilities, largely to finance smart meter installations.[3] From 2009-2020, the CPUC annually reported on the state's smart grid activities.[4] As part of their last report, the CPUC provided a status update on the deployment of smart meters as of October 2019.[5] Less than one percent (<1%) of all San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas & Electric (PG&E) customers remained on older, analog meters.[6]

Recently, SDG&E, PG&E, and SCE have all submitted requests to the CPUC for upgrades to their current smart meter infrastructure. Detailed below in Table 1 are the project requests, costs, and reported purpose for the requested upgrades. The IOUs suggest that these upgrades are not only necessary but will yield needed improvements in customer billing systems, more refined resolution of energy usage data, and easier integration with DERs.

Table 1: Overview of IOU applications for smart meter and related system upgrades before the CPUC.

IOU	Project	Cost	Purpose
PG&E	Electric AMI 2.0 Program[7]	$194.5 M	Deployment of ~300,000 next-generation electric smart meters
PG&E	Gas AMI Program[8]	$452.6 M	Replacement of legacy gas meters and system upgrades
PG&E	Billing Modernization Initiative[9]	$761.3 M	Update billing services and data management systems
SDG&E	Smart Meter 2.0[10]	$825 M	Replacing Smart Meter 1.0 technology
SCE	NextGen Enterprise Resource Planning[11]	$1.162 B	Update technology backbone responsible for many central processes, including smart meter technology

A Decade of Residential Rate Re-Design – There are several ways to price electricity used by the customers of an electric utility. Traditionally, customers paid the same price for each unit of

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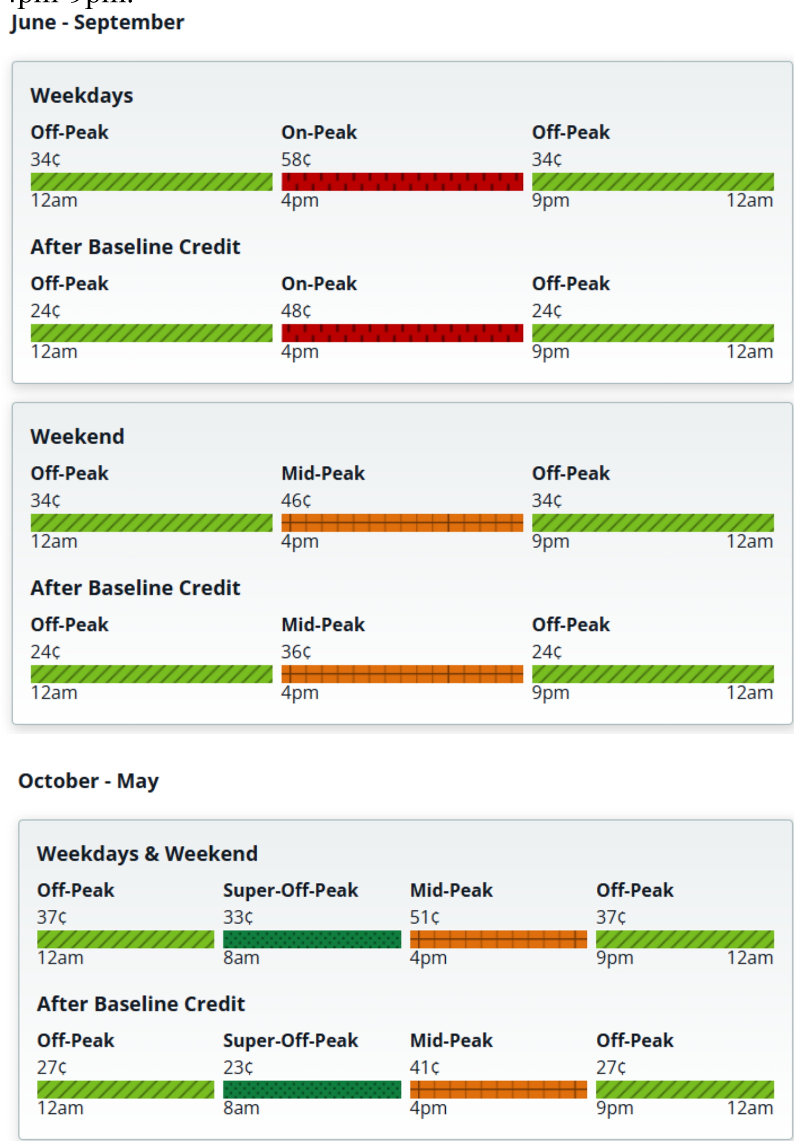
[3] *Ibid.*
[4] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/smart-grid-landing-page
[5] CPUC, *California Smart Grid Annual Report, 2019*, February 2020; https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/about_us/organization/divisions/office_of_governmental_affairs/legislation/2020/2019-smart-grid-annual-report.pdf
[6] largely due to their opting-out of the installation; see Table 4, pg. 38, *Ibid.*
[7] A.25-05-009
[8] A.25-05-009
[9] A.24-10-014
[10] A.25-12-012
[11] A.25-05-009

electricity, regardless of when they used it. More recently, IOUs have offered their customers electricity pricing that varies by time of day. The IOUs have offered time-of-use (TOU) rates to their non-residential customers for over a decade and have made them available to their residential customers, on an opt-in basis, for several years. This rate structure is to better align the price the customer pays for electricity with the cost to the IOU to generate, transport, and deliver that electricity.[12]

Figure *1*: TOU-D pricing plan for SCE, showing different pricing periods during different hours of the day and for different seasons (summer vs. winter months). Across each season, the highest prices are associated with the "peak" from 4pm-9pm.



To illustrate, an IOU customer subject to TOU rates pays more for each unit of electricity they use on a hot, sunny afternoon – when demand for electricity and costs of electricity generation are both high – than they do for each unit of electricity the customer uses in the middle of the night – when demand for electricity and the cost of generation typically are both low. In this way, TOU rates align costs and price signals, thereby encouraging customers to shift their use of electricity to times of low cost and low demand. By June 2022, all eligible residential customers of the state's three largest IOUs[13] transitioned to TOU rates. An example of a TOU rate structure from SCE is highlighted in Figure 1.[14]

The TOU rate structure, however, is a blunt signal. TOU time blocks encompass hours—typically, 4:00 p.m. to 9:00 p.m. for the most expensive TOU block—and the amount an IOU charges for each kilowatt of electricity a customer uses during those time blocks only loosely mirrors wholesale

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[12] Energy Upgrade California website; "Time Matters – FAQs;" accessed 03.25.2025; https://energyupgradeca.org/time-of-use-faqs#:~:text=When%20did%20Time%20Of%20Use,to%20TOU%20by%20June%202022.
[13] San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas & Electric (PG&E).
[14] SCE Time-Of-Use Plans; https://www.sce.com/save-money/rates-financing/residential-rate-plans/time-of-use-plans

electricity costs. In contrast, dynamic electricity rates price electricity closer to real time (typically every hour), better aligning with the actual cost to produce and deliver electricity. This is a common business practice, experienced by anyone who has faced surge pricing in an Uber or booked airline tickets during the summer travel season: prices rise when demand is high. In this way, dynamic pricing sends a much more precise signal to customers than do TOU rates, and customers can make fine-tuned changes in their use of electricity based on those precise price signals.

On July 14, 2022, the CPUC opened a rulemaking,[15] following the release of a CPUC Energy Division staff white paper on the California Flexible Unified Signal for Energy (CalFUSE), a proposal that includes integrating real-time price signals in customer rates with better DER management.[16] Recent studies that have analyzed the costs and benefits of DERs and other flexible resources show that a co-optimized system – i.e., a system that optimizes both the planning and dispatch of DERs with real-time price signals – can achieve significant long-term cost savings and partially mitigate the curtailment of renewable resources.[17] As part of the rulemaking, the CPUC initiated dynamic pricing pilots for SDG&E,[18] PG&E,[19] and SCE[20] to examine various customer behavior, system modifications, and customer needs before seeking to apply these activities statewide.[21]

In August 2025, the CPUC closed the proceeding and adopted guidelines for PG&E, SCE, and SDG&E to design demand flexibility rates and comply with the CEC's Load Management Standards.[22] Additionally, the CPUC directed SDG&E to propose demand flexibility rates for all customer classes by late November 2025, which was later extended to February 2026.[23] The decision also directed PG&E and SCE to provide additional information within their pilot programs' proceedings and to share any learnings from their pilots by May 2028.[24] In sum, there has been a directive from the CPUC to propose demand flexibility rates, but these proposals are still being developed and data are still being collected in ongoing pilots.

COMMENTS:

1) *Author's Statement.* According to the author, "To address California's electricity affordability and grid resiliency challenges, AB 1787 requires investor-owned utilities to offer at least one dynamic pricing option and real-time data access as a requirement of their next smart meter and system upgrade. By aligning consumer retail rates with

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[15] R. 22-07-005
[16] Madduir, A., et al., *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation;* CPUC; June 22, 2022; https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf
[17] Reeve, Hayden, et. al., "Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report," Pacific Northwest National Laboratory (PNNL), 2022. https://doi.org/10.2172/1842485.
[18] D. 21-07-010
[19] D. 21-12-015, D. 24-01-032
[20] D. 21-12-015, D. 22-10-022
[21] D. 24-01-032
[22] D. 25-08-049
[23] D. 26-02-001
[24] Order #7 of D. 25-08-049, pg. 148, directs a Tier 1 AL within 90 days after the final evaluation reports. D. 24-01-032 directed the expanded the pilots to conclude around December 2027, with final evaluation reports due March 1, 2028; putting the Tier 1 ALs at May 2028.

dynamic hourly wholesale costs, the bill encourages consumers to save money by reducing or shifting usage during time periods of abundant, low-cost renewable and carbon-free energy, which lowers bills for participating customers with flexible demand, and reduces overall grid stress and costs for all customers. Crucially, the legislation ensures these new rate designs are implemented without shifting costs between different customer classes."

2) *Purpose of Bill.* AB 1787 seeks to capitalize on planned smart meter infrastructure upgrades from IOUs by mandating an optional dynamic rate tariff to accompany the approval and deployment of those upgrades. Specifically, if the CPUC approves a request for smart meter infrastructure and related management and billing systems for an IOU and associated rate recovery, the IOU must also provide customers with an optional dynamic rate tariff.

   One goal of dynamic rates is to increase participating customers' demand flexibility. Renewables produce varying amounts of power in California based on when the sun is shining or the wind is blowing. Demand flexibility, or "load management," helps people adjust their energy use to better match the availability of clean electricity. For both residential and business consumers, load management has the potential to provide electricity bill savings when consumers opt in to using automated load-shifting devices such as smart thermostats, electric vehicle chargers, and appliances. The implementation of dynamic prices to harness these technologies and possible savings is largely still in pilot phases at the IOUs. This bill would require the IOUs to offer an optional dynamic rate tariff to all customers following updates to smart meter infrastructure, moving these rates from the pilot phase to broad application.

3) *Decades of waiting.* In 2006, PG&E received approval from the CPUC to deploy AMI upgrades, approval that was based on the expected benefits to both the utility and ratepayers from this upgraded infrastructure.[25] These expected benefits are echoed in the more recent proposals for smart meter upgrades noted above in Table 1, including improved access to customer data and the ability to have more refined management of grid load. However, in almost two decades of AMI deployment, dynamic rates made feasible by this technology are not widely available. The TOU rates, discussed above, offer some granularity in price signals to customers but fall short of the time-varying dynamic rates envisioned with smart meter technology. The decades-long development of these rates highlights not only the difficulty of striking the appropriate balance in rate design between encouraging customer behavior changes while maintaining ratepayer protections, but also the tension between having the available technology and not reaping all of the possible benefits. Given the pending applications by the large IOUs to modernize their smart meter infrastructure, it may be prudent to closely monitor the rollout of smart meter upgrades and ensure that the promises made will be the promises delivered.

4) *Order of operations.* As noted above (Table 1), the large IOUs already have requests before the CPUC to update their smart meters and related technology systems. This bill ties the approval of those upgrades to a requirement that IOUs must also provide an optional dynamic rate to all customers from whom the rates are recovered for the

[25] D. 06-07-027

infrastructure upgrades. The bill currently proposes two alternative sequences: in one, the dynamic rate tariff is offered to customers only after smart meter upgrades are complete and costs are recovered (§ 729.3(a)(1)); in the other, costs cannot be recovered until customers already have access to the optional dynamic rate tariff (§ 729.3(c)). This creates confusion as to what sequence the CPUC must follow, or what the IOUs must expect. Moreover, the latter sequence creates a difficult situation where the IOUs would be asked to front the costs of the smart meter upgrades while waiting for CPUC approval of their optional dynamic rate tariff, for which they would likely need to have the infrastructure in place to offer, leaving development of either at a probable standstill. As noted in the opposition from all three large IOUs, tying cost recovery of the smart meters to the approval of the dynamic rate tariff creates a possibly unfeasible timeline.

The author's intent is to ensure that customers reap the potential benefits, via an optional dynamic rate tariff, from the costs associated with updating the smart meter infrastructure. The author also acknowledges wanting the smart meter deployment to occur concurrently with the dynamic rate tariff development. Therefore, *the committee recommends clarifying the order of operations throughout the bill language to be consistent and match the author's intent. The recommended changes conform the bill with the first sequence: the dynamic rate tariff must be made available no later than when the infrastructure is anticipated to be placed into service.*

5) *Feasibility of real-time data sharing.* Smart meters and related infrastructure allow customers to have timely insight into their energy usage data. As mentioned, one key feature of dynamic rates is to capitalize on the more granular measurements available regarding grid conditions and energy usage. Furthermore, customers with smart meters are already able to access technologies that allow for real-time data sharing, such as smart thermostats, smart appliances, and DERs. In opposition, SCE and SDG&E have raised concerns about the bill requiring customers access to the data as soon "as data is generated." According to the utilities, the current technology planned for requested smart meter upgrades does not allow for "real-time" data sharing (unless the customer has the previously mentioned additional technologies), raising feasibility concerns with how the IOUs would comply.

   To ensure the language around the availability of data does not provide additional roadblocks to the development of dynamic rate tariffs, *the committee recommends clarifying that data available to customers is "near" real-time, matching what is feasible with planned smart meter upgrades. Additionally, the committee recommends further clarifications regarding customer authorization to share their data and for it to be done in a way that is safely accessible in a standardized format, while providing fairness across service providers.*

6) *Protecting customers and avoiding cost shifts.* The customers most likely to benefit from the dynamic rate tariff proposed to be offered under this bill are solar and storage customers with on-site equipment that tracks dynamic grid conditions and price signals, and savvy commercial and industrial customers with the time and financing (and, likely, dedicated staff) to maximize savings from dynamic pricing.

   Any change to customer rate design, even an optional one, may create unintended consequences. Vulnerable customers – i.e., elderly, low-income, or those with medical needs – may have limited access or understanding of the technology needed to optimize for cost savings under the new rate design. Moreover, it may not be feasible for all customers to participate in the optional tariff. For example, a customer who relies on energy-intensive medical equipment would likely not want to pay the true, dynamic price of using that medical equipment during peak hours. Customers who choose not to, or are unable to participate should be shielded from costs unintentionally shifted from participating customers.

It is the intent of the author to avoid cost shifts between participating and nonparticipating customers. In that spirit, the bill currently outlines requirements for the CPUC to periodically evaluate and mitigate any cost shifting from the optional dynamic rate tariff. *However, the committee recommends amendments that add explicit language for the CPUC to adjust or modify any dynamic rate tariff if found to have resulted in cost shifts during the evaluation, and to complete the evaluation at least once every four years. Additionally, the author recommends adding language for customers to be aware of the price risks associated with taking service under a dynamic rate tariff and that the CPUC consider rules or protections for vulnerable residential customers regarding participation in the optional dynamic rate tariff.*

The bill also requires IOUs to track and manage any energy subscription option offered to participating bundled customers and to ensure that the costs of that option are not shifted to nonparticipating customers. The energy subscription option is described as a hedge for customers participating in the dynamic rate tariff, allowing them to purchase a fixed quantity of electricity at a fixed rate to protect against risk when taking service under a dynamic rate tariff. While the principle of avoiding cost shift is present, the current language raises many questions, such as, whether the IOUs should be responsible for managing this cost shifting risk and what role energy subscription options play in establishing dynamic rate tariffs? *The committee recommends removing this provision and the author has suggested adding language that ensures nonparticipating customers do not pay for wholesale energy resources associated with the generation portion of the dynamic rate tariff. The committee recommends these changes.*

7) *Additional Amendments.* This bill requires additional clean-up or clarification. *The committee recommends removing the first legislative finding and editing the last to be focused on the potential for dynamic retail pricing if appropriate protections and safeguards are considered. The committee also recommends removing the first and last legislative intent and clarifying that customers can maintain their standard service if unable or uninterested in participating in dynamic retail pricing.*

The bill requires the optional dynamic rate tariff to include a distribution and a generation rate component. For transmission, the language ensures that the CPUC and IOUs consider relevant FERC regulations, but any transmission component is not explicitly made part of the dynamic rate tariff. Therefore, *the committee recommends clean up to remove any mention of a transmission rate and any related consultation with the California Independent System Operator in § 729.3(d)(4), and additionally clarify that load-serving entities should determine the generation rate as deemed appropriate and approved by the CPUC § 729.3(e). To provide further clarity, the committee recommends provisions throughout the bill to reduce repetitive or redundant phrasing, including* *removing language regarding distribution rate and its availability to all customers with the same electrical demand in § 729.3(d)(3).*

8) *Related Legislation.*

AB 710 (Irwin, 2026) requires the CPUC, by January 1, 2028, to require each electrical corporation to offer optional dynamic pricing tariffs consistent with CEC standards and a CPUC pricing framework. Additionally, requires electrical corporations and POUs to analyze, by January 1, 2028, the feasibility of deploying advanced metering infrastructure to all customers, and develop a plan, by January 1, 2029, for complete advanced metering infrastructure deployment, where feasible. Status: In Senate Committee on Rules.

9) *Prior Legislation.*

AB 1117 (Schultz, 2025) created optional, dynamic electricity rates for IOU customers. The bill also aimed to ensure that adopting these new rates doesn't unfairly shift costs between different customer groups. Additionally, the bill authorized medium and large commercial and industrial customers to receive generation service through the Direct Access (DA) program, thereby opening the current statutory cap on this third-party service. Status: Held in the Senate Committee on Appropriations.

SB 541 (Becker, 2025) required the CEC, as part of an existing biennial report, to estimate each retail supplier's load-shifting potential, considering certain factors such as cost-effectiveness, and to publish, on or before July 1, 2028, and biennially thereafter, the amount of load shifting that each retail supplier achieved in the prior calendar year. Status: Vetoed.

SB 846 (Dodd, 2022), 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.

AB 242 (Holden, 2021) struck a statutory requirement that the CPUC annually report on smart grid deployment (previously Public Utilities Code § 913.2) and updated an existing report focused on DER technology to include "progress made toward modernizing…the grid" (now Public Utilities Code § 913.6). Status: Chapter 228, Statutes of 2021.

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

SB 17 (Padilla, 2009) establishes the smart grid policy of the state and requires the CPUC to determine the requirements for a smart grid deployment plan no later than July 1, 2011. Status: Chapter 327, Statutes of 2009.

REGISTERED SUPPORT / OPPOSITION:

Support

Alliance for Retail Energy Markets
California Efficiency + Demand Management Council

Nrg Energy
Sierra Club of California

Opposition

Pacific Gas and Electric Company and its Affiliated Entities
San Diego Gas and Electric Company

Oppose Unless Amended

Edison International and Affiliates, Including Southern California Edison

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