BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

FILED
11/06/18
04:59 PM

P1811004

Petition of the California Solar & Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Inc., Solar Energy Industries Association, and Stem, Inc. to Adopt, Amend, or Repeal a Regulation Pursuant to Pub. Util. Code § 1708.5.	Petition 18-11-___

PETITION OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION, CALIFORNIA ENERGY STORAGE ASSOCIATION, ENEL X, ENGIE SERVICES, ENGIE STORAGE, OHMCONNECT, INC., SOLAR ENERGY INDUSTRIES ASSOCIATION, AND STEM, INC. TO ADOPT, AMEND, OR REPEAL A REGULATION PURSUANT TO PUB. UTIL. CODE § 1708.5

Brad Heavner,
On behalf of the Joint Petitioners

Policy Director
California Solar & Storage Association
1107 9th St., Suite 820
Sacramento, California 95814
Telephone: (415) 328-2683
Email: brad@calssa.org

November 6, 2018

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Petition of the California Solar & Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Inc., Solar Energy Industries Association, and Stem, Inc. to Adopt, Amend, or Repeal a Regulation Pursuant to Pub. Util. Code § 1708.5.	Petition 18-11-___

PETITION OF THE CALIFORNIA SOLAR & STORAGE ASSOCIATION, CALIFORNIA ENERGY STORAGE ASSOCIATION, ENEL X, ENGIE SERVICES, ENGIE STORAGE, OHMCONNECT, INC., SOLAR ENERGY INDUSTRIES ASSOCIATION, AND STEM, INC. TO ADOPT, AMEND, OR REPEAL A REGULATION PURSUANT TO PUB. UTIL. CODE § 1708.5

Summary

Pursuant to Section 6.3 of the Rules of Practice and Procedure the California Solar & Storage Association, California Energy Storage Association, Enel X,[1] ENGIE Services, ENGIE Storage, OhmConnect, Inc., Solar Energy Industries Association, and Stem, Inc (Joint Petitioners) submit this petition for rulemaking. Joint Petitioners request that the California Public Utilities Commission (Commission) open a rulemaking to address two broad topics related to retail electricity tariffs. First, the rulemaking should consider whether to order the state's three large electric investor-owned utilities[2] (Utilities) to offer optional real-time pricing (RTP) tariffs to all customer classes, and if so, whether to order the Utilities to offer other less

---

1 Enel X includes the demand response provider formerly known as EnerNOC as well as eMotorWerks, a manufacturer of electric vehicle charging equipment.

2 Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE)

complex dynamic rates, particularly for residential and small non-residential customer classes.[3] California utilities were early pioneers of RTP, but the only true RTP tariff available to the Utilities' bundled customers is a pilot rate offered by SDG&E for electric vehicle charging.

Historically, interest in RTP was driven by the desire to reduce peak loads, but the potential bi-directional load modification benefits of RTP are increasingly compelling for jurisdictions such as California with large shares of variable renewable resources. Several jurisdictions in the United States and abroad have moved beyond pilots and have successfully implemented RTP tariffs for one or more customer classes. Additionally, many direct access retail providers in competitive retail markets offer variations of RTP for both non-residential and residential customers.

The second purpose of the proposed rulemaking is to request that the Commission consider two demand charge-related reforms that would apply consistently across the Utilities' territories for non-residential customers currently subject to demand charges.[4] Both reforms are intended to improve the correlation between utility cost incurrence and the allocation of those costs to customers. First, the Commission should adopt a policy prohibiting the use of non-coincident demand charges, at least for the costs of any shared facilities beyond a customer's final line transformer. Individual customers' peak demands do not necessarily correlate with coincident peak demands at the system-wide, local capacity area, substation, or feeder levels of the electric system. Non-coincident demand charges are poor proxies for customer impacts on capacity-related costs, whether related to generation or delivery infrastructure.

The use of non-coincident demand charges in several of the Utilities' tariffs incentivizes

---

3 For purposes of this petition, we define real-time pricing tariffs as tariffs with hourly or sub-hourly retail prices that are based on wholesale prices and that are determined on either a day-ahead of day-of basis.

4 The Joint Parties are recommending review of demand charges for non-residential customers already subject to demand charges and are not suggesting consideration of new demand charges for customers not on demand-based rates.

uneconomic operations of storage assets and other demand reduction strategies. While non-coincident demand charge management has helped drive the value proposition of storage for customers, Joint Petitioners recognize that it may not be the best use of behind-the-meter storage assets for providing grid benefits. When customer price signals are not aligned with true costs and benefits, a perverse incentive arises that can lead storage systems to operate in ways that fail to avoid utility costs and may increase greenhouse gas (GHG) emissions.

Second, the Utilities' tariffs calculate customers' demand charges based on their highest single interval of demand (or highest interval during peak hours) in each billing period, commonly referred to as monthly maximum demand charges. Customers' highest intervals of demand, even during a tariff's peak period, may frequently occur on a day of relatively low systemwide demand. There is simply no cost basis for levying a large demand charge for a single, high-usage interval occurring on a low-demand day on the grid. Joint Petitioners suggest several alternatives to coincident monthly maximum demand that the Commission should explore, including daily coincident demand charges, charges based on an average of some number of the highest coincident intervals in each billing period, optional dynamic coincident demand charges, and ex-post demand charge mechanisms based on customers' contributions to measured system peaks the previous year.

Joint Petitioners believe that the Commission should open a rulemaking in order to develop consistent, explicit policies on RTP and demand charges. Considering these rate design elements in one proceeding would help to expedite the promulgation of the Commission's vision for advanced rates across the Utilities' territories. Opening such a proceeding would also further the objectives of Action Elements 1.4, 1.6, and 1.9 in the updated DER Action Plan, which the

Commission endorsed on May 3, 2017.[5]

1 Real-Time Pricing and Other Advanced Dynamic Rates

1.1 Benefits of Real-Time Pricing

Real-time pricing of electricity offers several potential benefits for consumers and California's electric grid. Economists have long argued that RTP offers substantial economic benefits as customers reduce usage during periods of high marginal cost.[6,7] Some economists have argued that the enormous economic damages of the Electricity Crisis could have been substantially mitigated if a meaningful share of customers had been on RTP or other dynamic rates.[8]

In jurisdictions where RTP has been implemented, customers have provided significant load response. Among older programs, Barbose et al. report that most of the RTP programs they examined showed participants' peak load reductions ranging from 10% to 33%, although it should be noted that these are mostly self-reported findings from the utilities that implemented the programs.[9] In a recently released report, Itron estimated that system-wide costs avoided by storage systems installed under SGIP would have increased from $4/kW to $83/kW installed for SDG&E if customers had been on an RTP-like rate rather than their actual rates.[10]

---

5 California Public Utilities Commission, (2017). "California's Distributed Energy Resources Action Plan: Aligning Vision and Action." http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20CLEAN.pdf

6 Severin Borenstein. (2005). "The Long-Run Efficiency of Real-Time Electricity Pricing." *The Energy Journal* 26 (3): 1 – 24. http://faculty.haas.berkeley.edu/borenste/download/EnJo05RTPsim.pdf

7 See also Vickrey (1971) and Schweppe et al. (1980) cited in Galen Barbose, Charles Goldman, and Bernie Neenan. (2004). "A Survey of Utility Experience with Real Time Pricing." Lawrence Berkeley National Laboratory, LBNL-54238. https://emp.lbl.gov/sites/all/files/report-lbnl-54238.pdf

8 Lee Friedman. (2009). "The Long and Short of It: California's Electricity Crisis." *Int. Journal of Public Policy* 4 (1/2): 4 – 31. Available at https://gsppi.berkeley.edu/lee-friedman/documents/Long%20and%20Short%201008.pdf

9 Barbose et al., 30.

10 Itron. (2018). 2017 SGIP Advanced Energy Storage Impact Evaluation. 1-21 – 1-22 (note page numbering is "chapter-page" format).

RTP has several advantages compared to less sophisticated dynamic rates, such as critical peak pricing (CPP). While CPP may offer similar load reductions on the days of highest demand, CPP's effectiveness is limited by certain features of its program design. CPP cannot capture hours of high market prices that occur on non-CPP event days or price spikes that occur outside of the summer season when CPP is in effect. Additionally, the Utilities are only allowed to call up to 15 CPP event days per year, which reduces CPP's value during a summer season with a large number of exceptionally hot days.[11]

The enhanced accuracy of RTP helps facilitate the integration of large shares of renewable energy in California's portfolio by unleashing the capability of customer-sited storage to respond to sudden changes in renewable energy output or other contingencies because it incents customers to adjust loads with more surgical precision. This capability would be further improved by the availability of RTP tariffs based on the real-time market in addition to tariffs based on the day-ahead market. As California obtains increasing shares of its electric supply from renewable energy, more short-term load flexibility will be needed to integrate larger proportions of energy from variable sources. High penetrations of variable renewable energy tend to lower average wholesale prices but increase price volatility and the cost of ancillary services.[12] Due to the volatility of wholesale energy prices, economists estimate that even well-designed time-of use rates capture only a fraction of the potential economic efficiencies provided

---

http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/2017_SGIP_AES_Impact_Evaluation.pdf

[11] Joint Petitioners do not intend to suggest that RTP should replace CPP. Rather, we believe that RTP and CPP should serve as complements, with RTP passing through accurate, granular energy prices, and CPP (or a similar dynamic rate) conveying a price signal related to the capacity needed to serve the highest system-wide peaks of the year.

[12] Joachim Seel, Andrew Mills, Ryan Wiser, Sidart Deb, Aarthi Asokkumar, Mohammad Hassanzadeh, Amirsaman Aarabali. (2018). "Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices and on Electric-Sector Decision Making." Lawrence Berkeley National Laboratory, LBNL-2001163. https://emp.lbl.gov/publications/impacts-high-variable-renewable

by RTP.[13] As the costs of storage and automated demand response technologies decline, more customers will have the ability to shift loads over short time horizons in response to price signals.

Compared to CPP, the potential benefits of RTP increase under the current paradigm with abundant supplies of solar energy suppressing mid-day wholesale prices, resulting in a growing incidence of negative pricing events.[14] Availability of RTP would enable customers with storage or other flexible loads to take full advantage of low prices during periods of oversupply in addition to reducing loads in response to high prices.

The California Independent System Operator (CAISO) Board recently approved a load-shift demand response product, referred to as Proxy Demand Response-Load Shift Resource (PDR-LSR), for the purpose of incentivizing consumption during negative pricing events.[15] While Joint Petitioners welcome this development, RTP offers several advantages compared to PDR-LSR that may appeal to a broader market segment. First, some customers may prefer the simplicity of enrolling in a tariff rather than having to register in a complex CAISO program and possibly aggregate their storage systems to meet the 100 kW minimum threshold. Second, RTP avoids the inherent uncertainties in setting customer-specific baselines, which is necessary in demand response-like programs. Third, RTP enables customers with a higher risk tolerance to expose their entire demand to wholesale prices rather than the limited exposure of deviations from their baselines. Fourth, whereas PDR-LSR only allows resources to bid increased

---

[13] William Hogan. (2014). "Time-of-Use Rates and Real-Time Prices." https://sites.hks.harvard.edu/fs/whogan/Hogan_TOU_RTP_Newark_082314.pdf

[14] Andrew Mills and Ryan Wiser. (2014). "Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels." Lawrence Berkeley National Laboratory, LBNL-6590E.

[15] See related materials at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=97C3E62B-ECDB-4CCC-AC3D-98263F57F5E4

consumption during negative pricing intervals, RTP allows customers to benefit from intervals with low, but still positive, wholesale prices.

Availability of RTP tariffs would also send the right price signals to customers about marginal GHG emission rates. Given California's energy supply, wholesale prices and GHG emission rates are closely correlated because the wholesale price is usually set by the bid of the least-efficient gas-fired generator that clears the market. The rough approximations of wholesale prices embedded in TOU rates are not sufficiently accurate to extract the full potential GHG savings achievable by storage systems and flexible loads.

Inaccurate price signals were the primary factor underlying the findings in a recent impact evaluation of the Self-Generation Incentive Program (SGIP) that participating storage systems likely increased GHG emissions, albeit by a very small amount, in 2016 and 2017.[16,17] Two factors in particular incentivized storage systems to charge and discharge at inappropriate times: out of date time-of-use time periods and the presence of non-coincident peak demand charges in the tariffs, which are discussed below. Modeling performed by EnerNOC (now part of Enel X) and PG&E as part of the SGIP GHG Signal Working Group, which was formed to recommend improved GHG monitoring and compliance options for SGIP-funded storage systems, suggests that an RTP rate would be highly effective at incentivizing storage systems to reduce GHG emissions, although ratemaking topics were considered to be out of scope of the Working Group.[18]

1.2 History of RTP and Current Availability

---

[16] Itron. (2018). 1-17.

[17] The increase estimated by Itron in 2017, 1,552 metric tons, was approximately 0.002% of California's 2016 electric sector GHG emissions.

[18] Ryan Mann and Jan Grygier. (2018). "Simulation of Proposed GHG-Reduction Solutions with Open-Source Energy Storage Model." 39-41.

The first utility known to have piloted RTP was PG&E in 1985. SCE followed shortly thereafter with an RTP tariff introduced in 1987. Initially prices were administratively determined, but during the years that the Power Exchange was in operation (1998 – 2001), prices were based on day-ahead market prices.[19] The Tennessee Valley Authority and Niagara Mohawk were also early RTP adopters that launched programs in the 1980s. Numerous utilities across the country began to offer RTP, often on a pilot basis, in the early to mid-1990s. However, interest in RTP and other innovative tariff offerings declined by the latter part of the decade, including at PG&E, which closed its RTP tariff in 2003. Barbose et al. attribute this decline to utilities' desire to focus on restructuring-related issues.[20, 21]

Despite the initial boom and bust of interest in RTP during the 1990s, many jurisdictions now offer some form of RTP to their customers. Georgia Power was an early RTP pioneer and is considered a leader in successful RTP implementation. Georgia Power currently has approximately 2,300 non-residential customers enrolled, representing 20% of its retail revenues. Most customers take service on a day-ahead tariff, but very large customers (>5 MW) are on hour-ahead RTP.[22] In Illinois, Commonwealth Edison (ComEd) has 9,000 non-residential customers on RTP.[23] The New York Public Service Commission (NY PSC) has required customers with maximum demands over 300 kW to be on mandatory hourly pricing since 2006.[24, 25]

---

19 Barbose et al., 94-95.
20 Barbose et al, 10.
21 Barbose et al. 88, 95.
22 Faruqui. (2017).
23 Ahmad Faruqui. (2017). "Dynamic Pricing: What Can We Learn from Other Jurisdictions?" Presented at the CPUC, December 12, 2017. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Rates/Faruqui%20Rate%20Design%20Panel%203%20Presentation.pdf
24 New York Public Service Commission. (2015). "Order Instituting Further Proceedings and Requiring the Filing of Draft Tariffs." http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0DDFAD32-C84A-4DDD-BF18-924E6C7DE954%7D

In recent years, an increasing number of utilities have expanded RTP eligibility beyond its large industrial customer origins to include small business and residential customers. In Illinois, day-of RTP has been available to residential customers of ComEd and Ameren since 2007. Both programs are administered by Elevate Energy, a non-profit organization that designs and implements energy efficiency, solar, and smart energy management programs.[26] There are currently over 30,000 participating residential customers, and participants have saved over $28 million to date.[27] In order to facilitate customer awareness and understanding, ComEd posts estimated prices the preceding day and allows customers to sign up for phone, email or text alerts that alert them the day before when high real-time prices are anticipated the following day or the same day when price are trending higher than expected.[28]

Even more remarkable than Illinois' provision of optional RTP for residential customers, Spain made RTP the *default* rate for bundled residential customers in January 2014. Over 10 million households are currently enrolled.[29]

Ironically, in California, the state where RTP was first introduced, the only true RTP tariff available for bundled customers of the Utilities is a pilot electric vehicle charging tariff recently adopted for SDG&E.[30] The tariff, referred to as Schedule VGI (Vehicle Grid

---

25 It is noteworthy that the NY PSC made RTP mandatory for larger customers due to its dissatisfaction with the utilities' education and marketing efforts.

26 Elevate Energy. (2018). About Elevate Energy. https://www.elevateenergy.org/about/ accessed September 2018

27 Jeff Zethmayr and David Kolata. (2017). "The Costs and Benefits of Real-Time Pricing." https://citizensutilityboard.org/wp-content/uploads/2017/11/FinalRealTimePricingWhitepaper.pdf

28 ComEd. (2018). "Hourly Pricing Program Guide 2018." 10. https://hourlypricing.comed.com/wp-content/uploads/2018/06/2018-HP-program-guide-v7.pdf

29 Javier Reneses. (2017). "RTP in Spain as Default Domestic Rate." Presented at the CPUC, December 12, 2017. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Rates/Reneses%20Rate%20Design%20Panel%203%20Presentation.PDF

30 Although SCE currently has a tariff among its rate schedules called RTP, it is not a true RTP. Instead day-ahead temperatures trigger one of nine different TOU profiles (five summer weekday, two winter weekday, and two weekend). See "Real-Time Pricing (RTP): How Much You Save Is up to You." https://www.sce.com/wps/wcm/connect/04ae933b-cafa-4412-bbe4-8a1ab443f81c/RTP+FACT+Sheet_NR-2225-V1-0413.pdf?MOD=AJPERES. Note that the number of summer weekday profiles will be reduced to three upon implementation of D.18-07-006.

Integration), is available only to electric vehicle charging at stations that are part of SDG&E's VGI Pilot Program.[31] Joint Petitioners commend SDG&E for designing and supporting the VGI rate, which includes not only day-ahead hourly rates based on prices in the CAISO day-ahead market, but generation and circuit-specific distribution capacity adders as well.[32] Similar rates should be opened up for all customers across the state on a voluntary basis.

The examples provided above pertain only to tariffs offered to bundled utility customers. Direct Access providers have greater freedom to design rates and offer RTP in restructured jurisdictions around the world, including California. In some jurisdictions with retail competition, Direct Access providers have begun to offer RTP to residential customers.[33]

These examples of RTP tariffs currently in effect in numerous jurisdictions in the U.S. and abroad demonstrate that customers, including residential customers, will accept and benefit from RTP. The growing proliferation of storage, electric vehicle, and automated demand response technologies is rapidly enhancing customers' ability to respond to dynamic prices. Access to RTP would further California's renewable energy, DER, and transportation electrification goals while minimizing grid impacts and GHG emissions. California has a long history of innovative rates and should reclaim its leadership position through thoughtful implementation of RTP and other dynamic rates.

1.3 Other Advanced Dynamic Rates

In addition to RTP, the rulemaking should consider whether to require the Utilities to make other, less complex dynamic rates available. These rates would fall between the complexity of RTP, with prices differing on an hourly or sub-hourly basis, and CPP, with one

[31] The pilot program and conceptual description of the VGI rate were approved in D.16-01-045.
[32] See VGI tariff details at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_VGI.pdf.
[33] See for example this service available in Texas from Griddy. https://www.gogriddy.com/residential-membership/

pre-defined critical peak rate extending across a pre-defined peak period of several hours. Offering dynamic rates with an intermediate level of complexity may entice some customers who might balk at full exposure to the volatility of wholesale prices to enroll in a rate with more accurate and flexible prices than CPP. Examples of such rates include the "RTP" rate that SCE currently offers and Oklahoma Gas & Electric's (OG&E) SmartHours-VPP (Variable Peak Pricing) tariff. On SmartHours-VPP, OG&E residential customers in Arkansas and Oklahoma are charged one off-peak rate during the summer, but one of four different weekday peak period (2 pm – 7 pm) prices that range from 5 cents to 41 cents per kWh. Participating customers can receive a free programmable communicating thermostat that responds to price signals automatically according to customer preferences. Participants can also choose to receive day-ahead notices by any combination of phone, text, or email.[34] An evaluation of the pilot study that led to implementation of SmartHours found that customers with programmable communicating thermostats on the variable peak pricing rate reduced peak loads by 27% during the highest-priced "critical events."[35]

2 Demand Charge Reform

2.1 Background on Non-Coincident Demand Charges

A recent report released in conjunction with the Commission's December 2017 Advanced Rate Design Forum describes how non-coincident peak demand charges were historically used as a proxy for an individual customer's contribution to coincident peak loads. Non-coincident demand charges were necessitated by limitations of metering technology because

[34] For SmartHours FAQs and price schedules see https://oge.com/wps/portal/oge/save-energy/smarthours.

[35] Craig Williamson and Katie Chiccarelli. (2012). "OG&E Smart Study TOGETHER: Technology Enabled Dynamic Pricing Impact Evaluation." Presented at the International Energy Program Evaluation Conference, Rome, Italy. http://www.iepec.org/conf-docs/papers/2012PapersTOC/papers/058.pdf

mechanical demand meters could only measure maximum kW consumed between meter readings.[36] With the advent of digital interval meters, these charges have become anachronistic.

Non-coincident demand charges suffer from two critical shortcomings. They tend to bill customers inaccurately with respect to their impact on coincident peaks since many customers' peaks demands do not correlate well with coincident peak demands. This holds true for any level of the electric system that serves multiple customers, whether at the system-wide, local capacity area, substation, or feeder levels of the system. Non-coincident charges also tend to unfairly allocate costs to customers with more variable loads because non-coincident charges do not recognize the load-smoothing benefits of load diversity across large numbers of customer accounts.[37] For these reasons, Linvill et al. argue that non-coincident peak demand charges should, at most, only be used to recover costs associated with an individual customer's service beyond the service drop.[38] Borenstein goes even further, arguing that because customer-specific capacity costs are both fixed and sunk (once the service connection has been established, the customer's subsequent peak usage has no impact on that equipment), non-coincident demand charges are never justified.[39]

The use of non-coincident demand charges leads to several undesirable outcomes. In the 2017 SGIP Impact Evaluation, Itron identified non-coincident demand charges as one of the primary causes for the disappointing avoided cost and GHG performance of storage systems participating in the program. As Itron described, the vast majority of non-residential customers in their sample had some form of non-coincident demand charge, and management of those

---

[36] Carl Linvill, Jim Lazar, Max Dupuy, Jessica Shipley, and Donna Brutkoski, (2017). *Smart Non-Residential Rate Design*, 10. https://www.raponline.org/wp-content/uploads/2017/12/rap_linvill_lazar_smart-non_residential_rate_design_2017_december.pdf

[37] Linvill et al. 12.

[38] Linvill et al. 16.

[39] Severin Borenstein. (2016). "The Economics of Fixed Cost Recovery by Utilities." 16. http://ei.haas.berkeley.edu/research/papers/WP272.pdf

charges provided far more value to customers than load shifting in response to TOU energy charges. The outsized importance of managing demand charges led many systems in the program to discharge a significant share of the time during summer partial-peak and off-peak (low-GHG) periods and to charge during peak (high-GHG) periods.[40] Itron and Linvill et al. both note that non-coincident demand charges incentivize customers to reduce load even during hours when increased load would be desirable, such as using electricity during periods of high solar generation to charge stationary storage systems or electric vehicles.[41, 42]

Many of the Utilities' non-residential tariffs have included a superior alternative to non-coincident demand charges for many years – TOU, or coincident, demand charges. As implemented in California, these charges are set according to customers' single highest interval of usage during pre-defined peak hours. Although coincident demand charges better incentivize load reductions during the highest cost hours, they still fall short as a reliably accurate proxy for customers' contributions to actual system peaks. Inaccurate cost allocation occurs whenever a customer's highest load during the peak hours of a billing cycle occurs on a day of relatively low system load. The Joint Petitioners do not support non-coincident demand charges of any kind, but we have not determined that any single alternative to coincident maximum monthly demand charges is the sole preferred solution. Below, we offer a few suggestions that could be explored in the rulemaking we request.

2.2 Alternatives to Maximum Monthly and Non-Coincident Demand Charges

In New York, Consolidated Edison's standby tariffs have included daily demand charges for many years. This approach to demand charge design splits the revenue that would be collected based on the single highest interval in each billing cycle into smaller charges based on

40 Itron. (2018). 1-9, 1-12.
41 Itron. (2018). 1-25.
42 Linvill et al. (2017). 38.

the highest recorded interval each day. Daily demand charges are superior to monthly maximum charges because they better reflect the average expected contributions to peak costs that demand charges are intended to capture and do not penalize customers for one anomalously high interval of demand. Experience in New York indicates that daily demand charges allow storage systems to provide more consistent value to customers because the penalty for failing to accurately predict, and reduce, the single highest interval in a billing period is not as severe. Daily demand charges also encourage greater capacity utilization because they incent storage systems to reduce peak loads every day (or weekday). Under a monthly maximum demand charge structure, if a storage system offsets an unusually large demand early in the billing cycle, and the battery management software doesn't detect a level of demand that approaches that benchmark during the rest of the billing cycle, it has little incentive to discharge the battery until the next billing cycle.

Another possible alternative is a variation on the "Top 30-hour" demand charge PG&E put forward in its default residential TOU application as part of a proposed pilot rate, referred to "E-DER-A," for customers with storage. The proposed demand charge would consist of the product of the demand charge rate (in this case $11.63/kW-month) and the average demand of the top 30 non-coincident hours in each billing period.[43] CALSSA opposed the E-DER-A rate in its opening testimony because it would apply to residential customers and would be based on non-coincident demand. Subject to additional analysis, a "Top X-hour" coincident demand charge may be an option with superior economic and environmental performance compared to

[43] PG&E. (2018). Pacific Gas & Electric Company Rate Design Window, Supplemental Testimony Vol. 1. 7-4 – 7-8, 7-11 (note page numbers are in chapter-page format). https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=528003

both coincident and non-coincident maximum monthly demand charges.[44]

In support of the Top 30-hour demand charge, PG&E argued that this demand charge structure is preferable to a daily demand charge because it would better incentivize customers to reduce load during a sustained heat wave.[45] In PG&E's hypothetical scenario, a customer on a daily demand charge may not make much effort to reduce cooling load over two or three hot days, knowing that the bill impact of a few days of high load will be mitigated by the averaging effect of spreading the demand charge across the other days of the billing period. PG&E makes a valid point; however, dynamic coincident demand charges could more accurately incentivize load reductions when most needed. These charges would be analogous to the use of CPP to recover the cost of the generation capacity needed to serve load on days of exceptionally high demand.

A final option that the Commission could explore is to levy a demand charge on customers in one year based on their load coincident with the system peak in the previous year. Some examples of this "ex-post" approach to demand charges include the Four Coincident Peak program in Texas, the Transmission Coincident Peak charge on Eversource's T-5 rate in Western Massachusetts, and the Installed Capacity charge in ISO New England. Although the specific intervals are not known in advance, they can be predicted with some measure of accuracy as they are typically highly correlated with weather. Consequently, customers are incentivized to drop loads during periods which might trigger a capacity event.

This structure has several advantages. First, because it is based on actual contribution to system peak, it avoids relying on other metrics to serve as a proxy for contribution to peak. Second, because the system peaks are not known in advance, customers are induced to drop load

---

44 Daily and average peak demand charges were both mentioned as possible alternatives to maximum coincident demand charges in D.14-12-080 (at 19), a decision further described below.

45 PG&E. (2018). 7-7 (note page numbers are in chapter-page format).

during a range of "candidate" periods, providing load reductions across the breadth of hours that plausibly coincide with system peaks. Third, unlike non-coincident demand charges, the narrower target periods incentivize customers to decrease as much of their load as possible, not just the portion above their baseload. Those customers that have the means to decrease usage, either through curtailment, deployment of energy storage, or other measures, can economically deliver deeper load reduction during periods of greater strain on the grid.

2.3 Review of Recent Commission Decisions Related to Demand Charges

The Commission discussed the inaccuracy of maximum coincident demand charges in considerable detail in D.14-12-080, which approved the Option R rate sought by SEIA in a PG&E Rate Design Window proceeding (Application 12-12-002). The decision cites analysis of solar customers' load and production data demonstrating that customers peak and part-peak demand charges were frequently not set by customers' demands on the days of highest system demand during the billing period. Moreover, SEIA found that during the highest 40 system peak intervals of the summer season, the average load of the customers studied was 203 kW, but the average maximum peak load billed for those customers was far higher, at 744 kW.[46] Based on SEIA's analysis, the Commission concluded that "Recovering coincident peak and part-peak capacity costs via maximum peak and part-peak demand charges does not reflect the diversity benefit of having numerous solar customers, and other erratic load customers, on the system."[47]

The allocation of costs to non-coincident demand charges and other billing determinants is regularly revisited in each utility's triennial application on marginal costs, revenue allocation,

[46] D.14-12-080. 15-18.
[47] D.14-12-080. 24, finding of fact 18.

and rate design, often referred to as the General Rate Case (GRC) Phase 2.[48] The Commission issued its most recent GRC Phase 2 decisions in 2016 for SCE, 2017 for SDG&E, and 2018 for PG&E. In the SCE case (Application 14-06-014), the Commission adopted five different settlement agreements, one relating to determination of marginal cost and allocation of revenue, with the others addressing various aspects of rate design for each of the major customer classes. The Commission accepted the settlement position for medium and large non-residential customers and agricultural and pumping customers that all distribution system costs beyond the final line transformer (referred to as "facilities" costs) be collected in monthly non-coincident demand charges. In contrast, generation-related capacity costs would be allocated differently to on-peak, mid-peak, and off-peak periods based on a loss of load expectation methodology.[49]

In SDG&E's GRC Phase 2 (Application 15-04-012), which was not settled, the Commission's decision evaluated the appropriate roles for coincident demand, non-coincident demand, and volumetric energy charges in considerably more depth. D.17-08-030 notes that at the time SDG&E filed its GRC Phase 2 application, 65% of distribution costs were recovered through a non-coincident demand charge and 35% through a coincident demand charge. In its application, SDG&E proposed to increase the non-coincident portion to 85%.[50]

The Solar Energy Industries Association (SEIA) submitted an alternative proposal to revise the allocation to 39% non-coincident/61% coincident. SEIA reasoned that distribution costs are not determined by the maximum loads of individual customers, particularly at the substation level where the load at any given moment is comprised of the combined loads of numerous customers. As described in SEIA's testimony, utilities design distribution

[48] It should be noted that FERC has jurisdiction over the allocation of transmission-related costs to retail rates. Except where noted below, the following discussion concerns the use of demand charges as they pertain to Commission-jurisdictional generation and distribution costs.
[49] D.16-03-030. 24-25, 33-34.
[50] D.17-08-030. 39-40.

infrastructure to accommodate the coincident loads at each level of the distribution system. This is particularly true for elements of the system, such as substations, that are further upstream from individual customers. SEIA derived its proposed split by allocating 100% of substation costs and 50% of feeder and local distribution costs to the coincident demand charge with the remainder allocated to non-coincident.[51] CALSSA argued forcefully for the allocation recommended by SEIA, pointing out the perverse incentives that non-coincident charges send to storage systems and the improved grid benefits of encouraging storage systems to reduce loads during coincident peak periods.[52]

Ultimately, the Commission adopted the allocation recommended in SEIA's testimony. The Commission acknowledged its own recent finding in D.14-12-080 that non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs. The Commission further reasoned that the flatter loads incentivized by non-coincident demand charges are less desirable than loads that follow solar output patterns.[53] Finally, the Commission noted that non-coincident demand charges discourage certain beneficial uses of electricity such as vehicle fleet charging.[54]

In the Commission's most recent GRC Phase 2 decision (in Application 16-06-013), the Commission rejected, in principle, PG&E's proposals to increase non-coincident demand charges in various tariffs, citing the reasons put forth in D.17-08-030.[55] The Commission stated it would only approve the proposed settlement agreement for medium and large commercial customers if settling parties agreed to shift a relatively small amount of cost recovery from non-

---

[51] D.17-08-030. 40-42.
[52] CALSSA. (2017). Opening Brief of the California Solar Energy Industries Association. 11-13. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K482/175482370.PDF
[53] Linvill et al. make a similar argument in the section of their paper on the importance of load shape rather than load factor.
[54] D.17-08-030, 45-47, 79-80, 90.
[55] D.18-08-013, 47-49, 170, 174.

coincident demand charges to coincident peak demand charges.[56] Settling parties agreed to that change. The Commission lamented a lack of record evidence to justify a larger shift, noting "While we approve the settlements on PG&E's rate designs in this proceeding, we wish to state clearly that we approve them in spite of the considerable backsliding away from cost-based rates that the proposals represent."[57]

Despite approving a settlement that increased non-coincident demand charges for many tariffs, the Commission made positive steps with the approval of an Option S rate for large customers with storage, based on the currently available Option R rates for solar customers, which have lower demand charges, but higher volumetric rates, compared to the otherwise applicable rates. Option S differs from Option R in two significant ways. First, it shifts 80% of the revenue collected from monthly non-coincident demand charges in the Option R rates to coincident peak demand charges. Second, it converts both the portion of non-coincident demand charges shifted to coincident peak and the existing coincident peak charges from Option R to daily coincident peak demand charges. The Joint Petitioners commend the Commission for approving Option S, but unfortunately, participation is capped at 150 MW of storage capacity. [58]

In SCE's 2018 GRC Phase 2 (Application 17-06-030), SCE disaggregates distribution system costs between "grid-related design demand costs" and "peak capacity-related design demand costs." A settlement filed by SCE covering rate design for medium and large commercial and industrial customers would shift a significant percentage of distribution revenue collection from non-coincident "Facilities-Related Demand" charges to coincident peak "Time-

---

[56] D.18-08-013, 81-85.
[57] D.18-08-013, 49.
[58] D.18-08-013. 105-112, 164-165, 176, 185-186.

Related Demand" charges and TOU energy charges.[59] In support of the settlement, SCE states that the settled rates "embody the Commission's recent guidance to shift cost recovery away from non-coincident peak methods…"[60] At the time this petition was filed, the Commission had issued a proposed decision approving the settlement.[61]

While transmission retail rates are FERC-jurisdictional, Joint Petitioners would like to encourage the Commission to continue pursuing greater movement toward time differentiation of transmission rates, the vast majority of which are collected via monthly maximum non-coincident demand charges. With the exception of a recent decision approving a joint stipulation between SCE and other parties under which SCE will file a request at FERC to move 30 percent of transmission cost recovery to TOU energy charges, little action has been taken to depart from non-coincident demand charges.[62] Recent GRC Phase 2 decisions for SDG&E and PG&E have only ordered those utilities to conduct studies on the appropriate allocation of transmission costs to non-coincident and coincident peak demand charges.[63, 64] These studies may provide useful information, but, ultimately, the Commission should be prepared to intervene more proactively before FERC to make meaningful progress on transmission rates.

3 Justification for Relief

California ratepayers and the market for customer energy management solutions would benefit from consistent Commission policy on RTP, other advanced dynamic rates, and demand charge reform. Joint Petitioners believe that opening one proceeding to set the policy parameters

---

59 SCE. (2018). Motion of Southern California Edison Company (U 338-E) and Settling Parties for Adoption of Medium and Large Power Rate Group Rate Design Settlement Agreement. 4-15, 21-23. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M231/K128/231128686.PDF

60 SCE. (2018). 23.

61 Decision on Southern California Edison Company's Proposed Rate Designs and Related Issues. Issued October 19, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M233/K818/233818732.PDF

62 D.18-05-040.

63 D.17-08-030. 92, Ordering Paragraph 34.

64 D.18-08-013. 178, Ordering Paragraph 6.

for all of the Utilities would most effectively accomplish this objective. The Commission has previously taken this approach when it considered whether to reform the tiered structure of residential rates and to default residential customers to TOU rates in R.12-06-013. Likewise, the Commission opened R.15-12-012 to consider methodologies for determining peak and off-peak time periods in TOU rates and to promote greater consistency among the Utilities.

Likewise, the Commission should open a rulemaking to consider the dynamic rate and demand charge issues discussed herein. A proceeding that includes all the Utilities would provide a single forum to consider the broader policies and related implementation issues such as whether to have both day-ahead and hour-ahead based options and which, if any, hedging mechanisms should be provided to limit RTP customers' exposure to market volatility.

Adoption of a consistent policy on demand charges would also be a great benefit to interested parties. Over the past several years, parties have had to continually re-litigate the inclusion and/or magnitude of non-coincident demand charges across a wide range of the Utilities' non-residential tariffs, as demonstrated in the above-cited GRC Phase 2 cases. In the past three years, Commission decisions have taken divergent and often contradictory positions on demand charge policy, including approving a settlement allocating nearly all distribution costs to a non-coincident demand charge, substantially shifting revenue collection to coincident demand charges from non-coincident demand charges, and approving a settlement that increased non-coincident demand charges for some rate schedules. The Commission's ability to adopt consistent policies that conform with its policy vision is enhanced when it proactively sets the agenda and determines the scope of a proceeding rather than reacting to the Utilities' individual applications and the case-specific trade-offs that often occur in the course of settlements. Additionally, participation by stakeholders is facilitated, and Commission staff resources used most efficiently, when major policy decisions regarding the Utilities' rates are decided in one proceeding.

4 Suggested Procedural Steps Should the Commission Grant Joint Petitioners' Requested Relief

If the Commission grants the Joint Petitioners' request to open a rulemaking and, as a result of that proceeding, orders the Utilities to offer RTP and reform their demand charges, we suggest that implementation details be considered in a consolidated set of rate design applications to be filed concurrently by each of the Utilities. CALSSA and SEIA are both parties to SCE's pending Medium and Large Power Rate Group Rate Design Settlement Agreement ("Settlement Agreement"), which, as noted above, the Commission has tentatively approved in a recent proposed decision. In the Settlement Agreement the settling parties agreed "that an RTP rate design based on wholesale energy prices from the CAISO markets can be explored by parties in SCE's 2021 GRC Phase 2 proceeding, assuming SCE's new Customer Service Replatform (CSRP) billing system is in place…"[65] In light of the terms of the Settlement Agreement, Joint Petitioners suggest that, pending the outcome of the rulemaking, the Commission order PG&E and SDG&E to file Rate Design Window applications concurrently with SCE's 2021 GRC Phase 2 application. Alternatively, with SCE's approval, the RTP issues could be removed from the GRC Phase 2 proceeding and filed in a separate application to be consolidated with PG&E's and SDG&E's filings. Joint Petitioners also prefer that any demand charge reforms arising from the Commission's orders be addressed in the same set of consolidated proceedings.

5 Requested Relief

[65] Motion of Southern California Edison Company (U 338-E) and Settling Parties for Adoption of Medium and Large Power Rate Group Rate Design Settlement Agreement filed August 3, 2018. 18.

Joint Petitioners request that the Commission issue an Order Instituting Rulemaking to consider the issues identified herein. Specifically, the rulemaking should have within its scope the following topics:

1. Real-Time Pricing and Other Dynamic Rates: Should the Utilities be required to offer RTP tariffs, on an optional basis, to all customers? If so, should the tariff be based on the day-ahead or real-time markets, or should both options be available? What marketing, education, and outreach efforts should be required to ensure that customers are aware of and understand RTP? Should the Utilities include locationally-specific price signals in their RTP tariffs to account for local grid conditions, similar to SDG&E's VGI rate? What, if any, hedging mechanism should be available to customers on RTP? Should the Utilities be required to offer additional dynamic rate options, similar to SCE's "RTP" or OG&E's SmartHours? Should the PG&E and SDG&E file Rate Design Window applications in coordination with SCE's 2021 GRC Phase 2 application to implement RTP and other dynamic rates?
2. Demand Charges: Should the Utilities be prohibited from including any non-coincident demand charges for Commission-jurisdictional costs in their tariffs? If not, should non-coincident demand charges be limited to the recovery of final line transformer and service connection costs? Should the Utilities be required to convert their monthly maximum demand charges (whether non-coincident or coincident peak) to daily coincident demand charges? Should other alternatives to monthly maximum demand charges be considered, such as coincident "top X hour," optional dynamic coincident demand charges, or charges based on contributions to previous peak demands? If the Commission adopts a standard policy on demand charges, should

updated tariffs be proposed in coordinated Rate Design Window applications?

Joint Petitioners appreciate the Commission's consideration of our petition.

Respectfully submitted,

/s/ *Brad Heavner*
on behalf of the Joint Petitioners

Brad Heavner
Policy Director
California Solar & Storage Association
1107 9th Street, Suite 820
Sacramento, California 95814
(415) 328-2683
brad@calssa.org

November 6, 2018

Attachment 1: Verification Statement Pursuant to Rule 1.11

Petition of the California Solar & Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Inc., Solar Energy Industries Association, and Stem, Inc. to Adopt, Amend, or Repeal a Regulation Pursuant to Pub. Util. Code § 1708.5 (Petition), filed November 6, 2018, was prepared under my supervision. The facts contained in the Petition are true and correct to the best of my knowledge. Any opinions expressed in the Petition reflect my best professional judgment.

I declare under penalty of perjury that the foregoing is true and correct.

/s/ Brad Heavner
Brad Heavner

Brad Heavner
Policy Director
California Solar & Storage Association
1107 9th St. #820, Sacramento, CA 95814
Telephone: (415) 328-2683
Email: brad@calssa.org

Dated: November 6, 2018

Attachment 2: Compliance with Rule 6.3

Rule 6.3 of the Rules of Practice and Procedure imposes various requirements on the filing of petitions for rulemaking (PFR). The Joint Petitioners address each of the specific requirements in turn.

Rule 6.3(a) requires that the regulations proposed in a PFR "must apply to an entire class of entities or activities over which the Commission has jurisdiction and must apply to future conduct." The regulations proposed in the PFR would apply to the three largest electric utilities under the Commission's jurisdiction, a class of electric utilities that is subject to many Commission regulations that do not apply to the small and multijurisdictional electric utilities and are prospective.

Rule 6.3(b) contains five separate requirements:

1. The petition must concisely state the justification for relief. We have included a justification for relief in Section 3 of the PFR.
2. If adoption or amendment of a regulation is sought, petitioners must include specific proposed wording for that regulation. Joint Petitioners have not sought a regulation per se. Rather, we have requested that the Commission open a proceeding to consider a set of issues related to electric rate design. In Section 5, we provide the proposed wording for the scope of such a rulemaking.
3. Petitioners must state whether the issues raised have been litigated before the Commission, and if so, how they were resolved and in which proceedings. In Section 2.3 we describe the last several rate cases that addressed demand charges and include the proceeding numbers. Apart from SCE's agreement to consider RTP in its next GRC Phase 2, as discussed in Section 4, we are not aware of any recent consideration of RTP before the Commission.

4. Petitions containing factual statements must be verified. Attachment 1 contains the verification statement of Brad Heavner.
5. Petition captions must contain the words "Petition to adopt, amend, or repeal a regulation pursuant to Pub. Util. Code § 1708.5." Our PFR has been captioned accordingly.

In compliance with Rule 6.3(c) we have served the PFR on the Executive Director, the Chief ALJ, the Energy Division Director, and the Public Advisor. Rule 6.3(c) further requires petitioners to consult with the Public Advisor regarding additional persons to be served. In compliance with this rule, we have consulted the Public Advisor and served the PFR on the service lists of the following proceedings: A.15-04-012, A.16-06-013, A.17-06-030 and A.17-12-011 (consolidated with A.17-12-012 and A.17-12-013).