FILED
08/15/22
12:22 PM
R2207005

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates	Rulemaking 22-07-005 (Filed July 14, 2022)

OPENING COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

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August 15, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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OPENING COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to Order Instituting Rulemaking 22-07-005 issued by the California Public Utilities Commission (Commission) on July 14, 2022 (the OIR or Rulemaking), the Solar Energy Industries Association (SEIA)[1] respectfully submits opening comments on this rulemaking proceeding intended to improve the ability of electric customers to shift or change their electric demand in ways that will help California achieve its climate, clean energy, and environmental justice goals.

I. INTRODUCTION

In the OIR, the Commission listed the following objectives which it hopes to advance through the demand flexibility policies adopted in this proceeding:

a. enhance the reliability of California's electric system;
b. make electric bills more affordable and equitable;
c. reduce greenhouse gas (GHG) emissions and the curtailment of renewable energy;
d. enable widespread electrification of buildings and transportation to meet the state's climate goals;
e. reduce long-term system costs through more efficient pricing of electricity; and
f. enable participation in demand flexibility by both bundled and unbundled customers.[2]

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1 The comments contained in this filing represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

2 OIR, p. 1.

The Commission states that it is concerned that its overall approach to encouraging demand flexibility is "piecemeal,"[3] and it seeks to undertake a broad review of its policies, programs, and rates to improve their effectiveness and advance the Commission's Environmental and Social Justice Action Plan.[4] SEIA welcomes this initiative, and, in these comments, we provide our thoughts on a number of the issues which will be addressed in this proceeding.

II. COMMENTS ON SPECIFIED ISSUES

A. How should the Commission update its rate design principles to enable widespread demand flexibility to improve system reliability and advance the state's climate goals in an affordable and equitable way?

As set forth in D. 15-07-001, the 2015 policy order on residential rate design, the Commission's existing ten rate design goals are as follows:[5]

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost-causation principles.
4. Rates should encourage conservation and energy efficiency.
5. Rates should encourage reduction of both coincident and non-coincident peak demand.
6. Rates should be stable and understandable and provide customers with options.
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.
8. Incentives should be explicit and transparent.
9. Rates should encourage economically efficient decision making.

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3 *Id*., p.2.

4 *Id.*

5 *See* R. 12-06-013 and D. 15-07-001, pp. 27-28.

10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

For the reasons discussed below, SEIA recommends modifications to Principles Nos. 2, 4, and 10. We also recommend the replacement of Principles Nos. 5 and 9 with new principles.

Principle #4. SEIA appreciates that the Commission has supported conservation and the efficient use of energy for decades, with the often-cited accomplishment of keeping per capita energy use constant for the past three decades.[6] This emphasis should continue, but the state's climate and clean energy plans have recognized that the state must also encourage other types of distributed energy resources (DERs) in addition to energy efficiency. These other DERs include demand response programs and technologies, renewable distributed generation (DG), behind-the-meter storage, high-efficiency heat pumps for space and water heating in buildings, and electric vehicles with large (but flexible) charging loads. The Commission has acknowledged that its climate and clean energy goals are only achievable in a "High DER" future in which all Californians make personal, long-term investments in all of these DERs, which collectively will be needed to reduce carbon pollution in the energy, building, and transportation sectors.[7] For example, electrifying vehicles (to replace the use of gasoline and diesel) and buildings (to displace natural gas for water heating and space conditioning) is widely viewed as the least-cost means to reduce carbon emissions in the transportation and building sectors, emissions that

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[6] This accomplishment is shown in http://www.energy.ca.gov/commissioners/rosenfeld_docs/rosenfeld_effect/presentations/NRDC.pdf , at page 3 of 24.

[7] On June 14, 2021, the Commission issued a Rulemaking 21-06-017 "to modernize the electric grid for a high distributed energy resources future."

accounted for 40% and 11% of the state's GHG emissions in 2019, respectively.[8] Accordingly, SEIA recommends that Principle #4 should be expanded to encompass all types of DERs, as follows:

4. *Rates should support the efficient use of energy and encourage customers to install cost-effective distributed energy resources that advance the state's climate and clean energy goals.*

Principle #5. This principle should be rewritten completely to reflect the realities of the current time periods during the day when electric demand is most critical for reliability. The coincident peak of end-use electric demand occurs in the late afternoon around 5 p.m., when there is still significant solar generation on the California Independent System Operator's (CAISO) system. These coincident peak hours are no longer the critical hours for reliability. Instead, the critical hours for reliability are the peak hours for the "net load" (end use demand less wind and solar generation), which occur later in the evening when the sun is setting. For example, the rolling blackouts on the CAISO grid on August 14-15, 2020, occurred in the net load peak hour between 7 p.m. and 8 p.m.

Further, state policy no longer supports reductions in a customer's non-coincident peak demand, which can occur in any hour. California's policy goals now support beneficial electrification, and DERs such as EVs can cause sharp new non-coincident peaks in a customer's electric demand. This new non-coincident demand is beneficial so long as it occurs at times when the system has adequate capacity and abundant low-cost clean energy.

In general, rate designs that encourage the reduction in non-coincident demands – for example, commercial and industrial (C&I) rates with large non-coincident demand charges –

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8 California Air Resources Board, *California Greenhouse Gas Emissions for 2000 to 2019: Trends of Emissions and Other Indicators* (released July 28, 2021), at p. 8 (Figure 4). Available at https://ww2.arb.ca.gov/sites/default/files/classic/cc/ca_ghg_inventory_trends_2000-2019.pdf.

encourage C&I customers to use electricity at high load factors. This type of rate design made sense when large baseload coal and nuclear plants were the least-cost sources of electricity. But such a rate structure makes little sense today. Today, the California grid relies on variable wind and solar resources, with increasing amounts of short-duration battery storage expected to store excess renewable energy to meet the evening "net load" peak after the sun sets. In this world, the most valuable customers (i.e., the least expensive to serve) are the ones with the flexibility to place their load on the grid at times when renewable energy is most abundant, and to minimize their use from the grid during the 4 p.m. to 9 p.m. peak hours. This is not a customer that is trying to reduce their non-coincident demand in every hour.

The overarching purpose of this OIR is to support demand flexibility. Flexibility means "the ability to be easily modified" or "willing to change." Rates are not going to send strong signals to customers to be flexible with their electric demand unless rates are time-dependent and dynamic. The existing rate design principles do not make specific reference to favoring time-of-use (TOU) rates, but they should. Time-dependent rates will advance a number of the Commission's stated rate design objectives. First, TOU rates more closely align rates with the utility's underlying marginal costs, which are themselves time-dependent. Second, TOU rates best reflect cost causation, as utility costs are caused principally by usage in certain time periods.

SEIA recommends that this rate design principle be re-written as follows:

5. *Time-varying rates should encourage demand flexibility that results in the beneficial use of electricity at times that support a reliable electric system and the maximum use of clean resources.*

Principles #2 and #9 can be consolidated. The Commission has long recognized that a fundamental reason why rates are based on marginal costs (Principle #2) is to encourage economically efficient decision making by customers (Principle #9). These basic principles should be further clarified to emphasize the use of long-run marginal costs. A long-run perspective is vital in order to encourage customers to make long-term investments in preferred DERs, in support of the state's efforts to replace California's current energy infrastructure with cleaner and more efficient technologies. Rates based on long-run marginal costs will be inherently more stable than rates based on short-run marginal costs. In the short-run, marginal costs are dominated by fuel costs and can be volatile when fossil fuel prices fluctuate. Reasonably stable and consistent marginal costs with a long-term perspective are critical to supporting the investments in DERs that California is asking its electric customers to make in support of the state's climate and clean energy goals.

SEIA recommends consolidating and clarifying Principles #2 and #9, as follows:

2. *Rates should be based on long-run marginal costs, to encourage economically efficient decisions and long-term customer investments in DERs.*

Principle #10. Changes in rates and rate structures can have a particularly serious impact on customers who have made significant long-term investments in DERs in reliance on the prior rate design. The Commission has recognized this concern in the legacy policies that it has adopted for net metering rules and for the TOU rates applicable to customers who install DG.[9] These sound policies should be referenced in Principle #10, which SEIA proposes to modify by adding the underlined clause:

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[9] See D. 14-03-041 and D. 16-01-044 for NEM legacy policies. D. 14-03-041, at page 3, states that these policies are designed to provide solar customers with adequate bill savings to allow "a reasonable opportunity to recoup the costs of their investment in those systems." The Commission found that "adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation." D. 14-03-041, at p. 20. For the legacy policies on TOU periods, see, for certain residential customers, D.16-01-044 at pp. 93–94, and, for all types of customers, D. 17-01-006 at pp. 57-66 and footnote 48.

10. *Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, protects customers' long-term investments in beneficial DERs, and minimizes and appropriately considers the bill impacts associated with such transitions.*

New Principle #9. By definition, fixed charges do nothing to send signals to customers to increase the flexibility of their electric demand. Customers have no ability to respond to fixed charges except to move their entire demand off the grid. As discussed further below, reductions in the costs of solar and battery technologies have increased the potential for significant grid defection, so the use of fixed charges must be limited and judicious. Fixed charges should be limited to utility costs that do not vary with usage – principally, customer access, metering, billing, and customer service costs. Such a limit recognizes that, in the long run, few costs truly are fixed. Customers are not going to make long-term investments in DERs unless rate design allows them to use DERs to manage and to reduce their energy costs in a meaningful way. SEIA recommends that the Commission state this as a new Principle #9:

9. *The use of fixed charges should be limited to utility costs that do not vary with usage.*

B. Should the Commission consider and/or authorize additional pilots, tariffs, programs, and/or studies to make demand flexibility options available to each customer class? If so, what factors should the Commission consider in assessing whether to authorize?

The Commission is well down the road to approving initial real-time pricing (RTP) / dynamic rate pilots for each of the three IOUs. The Commission recently approved the PG&E program in D. 22-08-002. RTP proposals have been briefed in SCE's current general rate case Phase 2 (A. 20-10-012), with a decision expected soon. SDG&E's application for an RTP pilot (A.21-12-006) is well underway. All of these RTP pilots have come out of the IOUs' recent GRC Phase 2 cases. SEIA welcomes further guidance from the Commission in this OIR on how to build on the design of these pilots, following the Energy Division's Demand Flexibility Whitepaper (Whitepaper). The in-progress RTP pilots appear to address several of the elements of the dynamic rate framework discussed in the Whitepaper, for example, Element 2 (energy pricing) and the generation capacity component of Element 3 (capacity pricing). We support the proposal being made by the California Solar & Storage Association (CALSSSA) in its opening comments that this OIR should focus first on developing the distribution capacity component of Element 3 and the transition to bidirectional electricity prices in Element 4. Elements 5 and 6, as set forth in the Whitepaper, involve different ways to "package" dynamic prices – in a subscription product or as a forward, transactive price – and how to recover utility costs beyond energy and capacity. These elements should be considered in a future phase of this OIR once the initial elements have been designed and experience gained in the initial pilots.

Moreover, the Commission should be cognizant that the solar industry is moving to solar paired with storage as its primary product. This is a major theme in the ongoing proceeding (R. 20-08-020) to revise the rules and compensation applicable to distributed solar and solar-plus-storage facilities. The Commission's pending decision in that docket will have a substantial impact on whether the state's rooftop solar industry continues to grow sustainably and can make the transition to solar-plus-storage as its central product. If it can do so, the growth of a fleet of distributed storage located at customers' premises on the distribution system opens up the potential for these units to provide important new grid services and demand response capacity. SEIA encourages the Commission to continue and to expand the ongoing work to optimize the benefits that these resources can provide to the system. This work includes:

- Allowing all solar and solar-plus-storage customers to access dynamic rate tariffs, including Critical Peak Pricing rates (CPP). These are the customers who are likely to be willing and best able to respond to such changing rate signals. SEIA is pleased that the initial proposed decision in R. 20-08-020 included a provision to ensure that all NEM customers have access to CPP rates.

- The aggregation of distributed solar-plus-storage into virtual power plants (VPPs) that can provide dispatchable Resource Adequacy (RA) capacity, with visibility to system operators. The Commission needs to prioritize and simplify the requirements for VPPs to participate in RA program. For example, these issues are not included in the scope of the current workshops to implement the set of "slice-of-day" RA reforms that the Commission has approved in D. 21-07-014 and D. 22-06-050.

Developing new opportunities for solar paired with storage to provide innovative demand response capacity and new grid services will be an important means to support customers' investments in this critical resource and to provide additional demand flexibility to the electric system.

In addition, SEIA urges the Commission not to ignore the need to make further progress in implementing stronger price signals encouraging demand flexibility in the rates now applicable to most residential customers. The IOUs have completed or will soon finish the initial transition to default residential TOU rates. The Commission should use this OIR to answer the question "what comes next?" For example, the default TOU rates of the IOUs do not have rate differences between TOU periods that are even close to underlying marginal costs – the PG&E and SDG&E default rates are particularly "TOU-lite" and send only weak price signals to customers to be flexible with their electric demand. SEIA has raised this issue in recent GRC Phase 2 cases for PG&E and SCE, and the residential rate settlement approved in D. 21-11-016 for PG&E, which SEIA supported, made modest progress in this area.[10] However, now is the time for the Commission to adopt a longer-term vision and framework for the pace and process to move default residential rates toward full marginal costs. Re-visiting residential rate structure only every 3 or 4 years in GRC Phase 2 cases is unlikely to make the rapid progress required to

[10] See D. 21-11-016, at pp. 106-108.

meet the exigencies of the climate crisis. SEIA suggests that the Commission consider adopting an annual schedule of changes to default residential TOU rates for each IOU that will make substantial progress by 2030 in moving default residential rates to marginal cost-based TOU rate differences.[11] In addition, many residential customers have elected to remain on old increasing-block rates, which do not send accurate price signals to encourage either demand flexibility or beneficial electrification. Increasing block rates convey no information about when to use electricity and penalize increasing usage from electrification. The Commission and stakeholders should develop new plans for marketing, education, and incentive plans to encourage more residential customers to move to time-sensitive rates.

Finally, there will be a need for the Commission to take timely action on rate design issues that arise between GRC Phase 2 cases. For example, some of the innovative electrification rates that the Commission has adopted have participation caps;[12] these caps are not likely to be reached at times that allow for a quick revision and extension in a GRC Phase 2. The Commission should be proactive in directing the IOUs to give advance notice of reaching such caps, and in reviewing and revising these rate options so that their availability is continuous.

C. How should the Commission reform demand charges for consistency with the adopted rate principles and demand flexibility guidance?

Demand charges do a poor job of encouraging customers to be flexible in when they place demand on the grid. As noted above, traditional C&I rates with large noncoincident

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[11] This could be similar to the plan that the Commission adopted in D. 15-07-001 in R. 12-06-013 for decreasing the tier differences in increasing block rates and reducing the number of tiers.

[12] For example, PG&E's popular EV2 rate option is open to only 30,000 residential customers who have battery storage but not an EV. See Special Condition 8 of the EV2 tariff.

demand charges (NCDCs) send a strong signal to C&I customers to use electricity at high load factors – in other words, to use a constant, inflexible amount of power in every hour including the peak load hours. Demand charges made sense in a world in which large baseload coal and nuclear plants provided the least expensive electricity, but that is not the world today. Today the most valuable customers (i.e., the least expensive to serve) are the ones with the flexibility to place their load on the grid at times when renewable energy is most abundant. Demand charges send the wrong signal to customers to use power at high load factors, without any flexibility to avoid peak hours or to take advantage of low-cost times. This is particularly true of NCDCs, which lack any time sensitivity and which reward customers who have a constant load in every hour. But it is also true of time-related demand (TRD) charges that may only apply during the 5-hour on-peak period. TRD charges are an improvement over NCDCs because they focus on high demand hours, but they still encourage customers to use up to their maximum 15-minute on-peak demand in every peak hour of the month; it provides no incentive to use less peak power in any 15-minute interval except in the interval that sets the maximum demand for the month.

For example, with a TRD charge, a customer who has maximum usage of 500 kW in 100 on-peak hours of the month will have the same bill for capacity as a second customer who uses 500 kW in just one hour of the month. Not all on-peak hours have critically high loads, but the first customer is much more likely than the second to use 500 kW during those most critical on-peak hours. In contrast to the TRD charge, a volumetric on-peak rate appropriately will charge the first customer more for their much greater and riskier use of capacity. The volumetric on-peak rate sends the customer a consistent signal to minimize their on-peak usage in every on-peak hour and rewards the second customer who used as little power as possible during peak hours. The accuracy of this signal can be further honed with volumetric Critical Peak Pricing

(CPP) rates that target very high rates, called in advance, to the limited number of on-peak hours when system conditions are particularly challenging.

In recent GRC Phase 2 decisions, the Commission has recognized the problems with NCDCs, and has taken steps to reduce their use and magnitude. For example, in D. 17-08-030 in an SDG&E GRC Phase 2 case, the Commission rejected SDG&E's proposal to recover 100% of its distribution costs through NCDCs in its medium and large C&I rates. Instead, the Commission adopted SEIA's proposal that 100% of substation costs and 50% of distribution costs should be collected through time-dependent rates; this reduced the overall recovery of distribution costs through NCDCs to 39%. It is useful to quote the relevant section of D. 17-08-030 to provide the full policy context for this decision:

> … the CPUC is moving to greater use of TOU and other time-varying rates. TOU is now mandatory for all C&I customers, we have established a transition plan for residential customers to move to default TOU rates, and TOU rates are now mandatory for net energy metering (NEM) 2.0 customers. This trend of increasing CPUC reliance on time dependent rates is important because it would be inconsistent to simultaneously increase our use of noncoincident demand charges which are non-time dependent.
>
> Noncoincident demand charges incentivize customers to flatten their load, but given high penetration of solar resources, solar-following loads are becoming more desirable to avoid curtailing renewable resources and may be less costly to serve than customers with flat loads. Noncoincident demand charges can discourage beneficial energy use, such as electric vehicle fleet charging (overnight or during hours with high solar generation), or Reverse Demand Response to encourage customers to use renewable energy that might otherwise be curtailed due to over-generation conditions….
>
> We have previously found that noncoincident demand charges do not reflect cost causation for primary distribution, transmission, nor generation capacity costs (D.14-12-080, Finding of Fact 8) and therefore adopting the SEIA proposal that 100 percent of SDG&E's upstream substation costs and 50 percent of its feeder and distribution circuit costs should be recovered in time-dependent, peak demand charges is a logical next step to move rate design towards alignment with cost causation.

Since D. 17-08-030, other GRC Phase 2 decisions also have reduced the use of NCDCs and encouraged the greater use of time-dependent charges in C&I rates.[13] SEIA urges the Commission to continue to reduce the role of NCDCs in C&I rate design in future GRC Phase 2 cases, and to announce in this OIR that this is the Commission's formal policy direction with respect to the use of NCDCs.

As noted above, time-related demand (TRD) charges also are flawed and fail to send the most accurate and targeted price signals. SEIA recommends that, as a result of this proceeding, the examination of the role of time-related demand charges, and whether these rate design elements should be replaced with volumetric TOU rates, be made an issue in each IOU's next GRC. The greater use of targeted rate elements such as CPP rates and dynamic rates linked directly to energy market prices or to CAISO system demand should also be a required part of such examination. SEIA observes that the recovery of generation and distribution capacity costs in dynamic, time-sensitive, volumetric rates has the potential to replace most demand charges and to result in rates that are much more accurately and precisely aligned with system conditions.

D. How should the Commission reform fixed charges for recovery of certain authorized utility costs in accordance with the adopted rate principles and demand flexibility guidance?

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[13] In the Medium and Large Light & Power (MLLP) settlement in SCE's 2017 GRC Phase 2 (A. 17-06-030), the parties agreed to Option E rates with NCDCs close to those that SEIA proposed in its litigation position (about $8 to $9 per kW-month). This represented a significant reduction from the noncoincident demand charges in SCE's Option R rates at that time ($11 to $17 per kW-month). The Commission approved this settlement in D. 18-11-027. For PG&E, D. 18-08-013 rejected a settlement on Medium & Large Light & Power (MLLP) rates, in favor of MLLP rates with lower non-coincident demand charges. The order cited D. 17-08-030, among other factors, and indicated, at pages 47-51, that the Commission expected to see further progress in the direction of lower non-coincident demand charges in future PG&E GRCs.

The only demand flexibility that fixed charges will promote is for customers to move their demand "off the grid," leaving the electric system entirely. Today, the levelized cost of a residential solar-paired-storage system that can meet an electric customer's essential needs without the grid is about 20 cents per kWh,[14] which is below current average residential electric rates. Customers increasingly are choosing such systems to provide backup service should the grid fail for an extended period.[15] These systems may not be quite ready for extended off-the-grid service, but they are close, and the cost of "grid defection" will fall as battery costs are reduced. SEIA expects that most solar customers would prefer to remain on the grid, and SEIA does not support policies that would encourage grid defection. One policy that would accelerate grid defection by residential customers would be the levying of large fixed charges that are income graduated, with higher-income customers paying the highest fixed charges.[16] Such a policy would send a strong signal to leave the grid to exactly the group of customers that can best afford to do so.

SEIA believes that fixed charges have a role to play in California's future rate design, but that role should be a limited one. In the long run, there are very few utility costs that are truly fixed and that do not vary with customers' usage. These truly fixed costs are limited to the costs of the facilities and services needed to provide access to the grid – the final line transformer, service drop, meter, and associated billing and customer support services – and are captured in

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[14] See R. 20-08-020, *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (June 18, 2021), at p. 19 (Figure 2 – see the Solar + Storage Levelized Cost of Energy [LCOE] for 2022-2023).

[15] In 2021 and 2022, 14% of solar customers included storage in their systems, based on data from the Commission's public "DG Stats" database of on-line distributed solar and storage capacity installed in the service territories of the three major investor-owned utilities. This includes data for both the residential and non-residential markets. See https://www.californiadgstats.ca.gov/.

[16] See Severin Borenstein, *Reinventing Fixed Charges* (November 16, 2020), at https://energyathaas.wordpress.com/2020/11/16/reinventing-fixed-charges/.

marginal customer costs. At the residential level, the utility's transmission and distribution systems serve multiple customers, and in the long run can be re-configured to serve additional customers if average residential demand is reduced as a result of customer investments in DERs such as distributed generation, energy efficiency, or demand response. The only "individualized" utility facilities that typically cannot be used to serve another residential customer are the transformer, service drop, and meter. In the past, the Commission has found that residential fixed charges should be limited to no more than marginal customer costs.[17]

SEIA recognizes that fixed charges allow volumetric rates to be reduced, which is important to supporting DERs that increase electric use and that compete with fossil fuels (such EVs and heat pumps). However, from a demand flexibility perspective, fixed charges lack time sensitivity and fail to send a price signal to reduce or time-shift electric use. As a result, fixed charges are harmful to those DERs that reduce or shift the use of energy from the grid – energy efficiency, demand response, renewable DG, and storage. Fixed charges limit customers' options to impact their energy bills through long-term investments in these preferred resource options. There is a balance to be struck here – fixed charges in residential rates should be limited to those costs that do not vary with usage, and low-cost power for load-building DERs should be supplied through rate designs with low off-peak rates. SEIA has supported the electrification rates for PG&E (Schedules EV2 and E-ELEC) and SCE (Schedule TOU-D-PRIME) that are consistent with this balanced approach. We recommend that the Commission continue to design

[17] See D.17-09-035, at p. 40: "In sum, a fixed charge should include only a portion of revenue cycle services costs and all meter capital costs and portions of service drop and final line transformer costs, as set forth in Table 2. Fixed charges cannot cover any costs that vary with demand and must exclude transmission charges and all non-bypassable charges such as public purpose program charges. The EPMC scalar will not be applied when calculating fixed costs for purposes of setting a fixed charge."

electrification rates that are broadly applicable to many types of DERs, with the use of fixed charges strictly limited to recovering no more than marginal customer costs.

SEIA is aware that recently the Legislature passed, and the governor signed AB 205, which requires the Commission to adopt fixed charges for residential default rates by July 1, 2024. The new legislation also requires the use of an income-graduated fixed charge with at least three income tiers, which would be an expansion of the current two income tiers (i.e., CARE and non-CARE). Today, CARE customers who take service on residential schedules with fixed charges[18] receive a discount in the fixed charge equal to the applicable CARE discount of 30% to 35%. To implement the three-tier scheme contemplated in AB 205, SEIA recommends adding a new tier that provides a discount in any residential fixed charge that is 50% of the applicable CARE discount, with the lower bound on the income to qualify for this reduced discount set at the threshold for qualifying for CARE (i.e., 15% to 17.5%). The Commission should determine the maximum income that would qualify for this new tier in the proceeding to implement AB 205.

Finally, and perhaps most important, past customer surveys by the IOUs have indicated that, of all possible rate design elements, significant monthly fixed charges elicited the strongest negative reactions among consumers.[19] This feedback deserves attention, given the critical importance of customer acceptance of any rate design.

In terms of process, as noted above, AB 205 requires the Commission, by July 1, 2024, to adopt new, three-tiered fixed charges for the default residential rates of all IOUs. Given the process requirements for changing rates, such as the need for a hearing, as well as the common

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18 For example, SCE's TOU-D-PRIME rate, which has a fixed charge of $12 per month.

19 See R. 12-06-013, "RROIR Customer Survey Key Findings," (April 16, 2013, Final Draft), at Slide 19.

issues in the design of the new fixed charges that all of the IOUs will face, we recommend that the Commission schedule a consolidated rate design window proceeding for all impacted IOUs that focuses on implementing the required fixed charges in default residential rates.[20]

E. How should the system benefits and savings resulting from demand flexibility be tracked, quantified, and incorporated into rates to pass on to customers?

In evaluating rates and programs designed to encourage demand flexibility, the Commission must look beyond simple metrics such as revenue recovery. Simply because a new rate recovers less revenue for the utility than the otherwise-applicable rate does not mean that the new rate causes an adverse "cost shift." If the new rate results in incremental electric use (for example, by being linked to adoption of a load-building DER), the incremental revenues in excess of marginal costs are a benefit for all other ratepayers. Similarly, if the new rate encourages customers to shift electric use out of peak TOU periods to off-peak periods with lower marginal costs, the marginal cost savings will offset the revenue loss. Finally, the benefits of DER adoption include significant reductions in greenhouse gas emissions that also should be quantified and considered. The Commission's evaluation of new rate designs must consider these more detailed analyses.

F. How should the Commission advance its ESJ Action Plan goals through demand flexibility rates, tools, programs, and/or reporting?

California has had a longstanding commitment of providing significant financial support to help low-income and medical baseline customers meet their electric energy needs. The CARE program is targeted at low-income residential ratepayers and provides a direct 30% - 35% reduction in energy bills. The baseline program represents a broader safety net than CARE and

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[20] This could be similar to the consolidated RDW process that the Commission used to implement default TOU rates (A. 17-12-011, -012, and -013).

is intended, like Social Security, to provide a basic amount of electricity to all consumers, regardless of income, at an affordable price. Baseline rates provide inland consumers in hotter regions with significantly larger baseline allowances than coastal customers. These larger baseline allowances in inland climate zones result in significant additional support for consumers in these warmer areas, because any regional differences in the cost of electricity are much smaller than the discount provided to inland consumers.

Both CARE and the baseline program support longstanding, explicit state policy goals. As the state pursues electrification, these programs for electricity will grow to encompass a larger share of residential customers' energy needs, as electricity is substituted for natural gas use in buildings and for liquid fossil fuels in transportation. The CARE and baseline programs also apply to residential natural gas customers, so reductions in gas use due to electrification simply may shift the dollars spent in the gas programs to the comparable electric programs. To SEIA's knowledge, there has never been a low-income subsidy program for gasoline, but low-income customers with EVs will qualify for the CARE subsidy for their costs to charge an EV at home. SEIA strongly supports the continuation of the CARE and baseline programs as the state moves toward electrification. With their expanding scope, these programs will add to the upward pressure on electric rates, a significant concern given the state's electrification goals. SEIA suggests that the Commission and Legislature explore funding the increased scope of the CARE program through sources other than electric rates. Another idea is to move away from the CARE and baseline structures that offer a uniform percentage discount (CARE) or cents per kWh discount (baseline) on all usage. Instead, the discounts could be greater for off-peak rates, in order to encourage the off-peak electric use at lower rates that will be essential to the success of electrification.

SEIA also encourages the Commission to explore new means to provide such support beyond simply subsidizing consumption. Given the future importance of DER adoption, the Commission should focus on programs to support DER adoption by low-income customers. Equitable access to investments in DERs will allow customers at all income levels to exercise greater choice and control over their sources of energy and their monthly energy bills. Customers will not be able to exercise such long-term choices if a substantial portion of their monthly budget for energy costs is consumed in a fixed charge paid to the incumbent utility.

III. CONCLUSION

SEIA appreciates the Commission's consideration of these initial comments and looks forward to further participation in this important rulemaking.

Respectfully submitted the 15th day of August 2022 at San Francisco, California.

By: /s/
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