Docket No: R.20-08-020___

Exhibit No.: SVS -04______

Date: July 16, 2021 (original)

July 22, 2021 (revised)

Witnesses: R. Thomas Beach

PREPARED REBUTTAL TESTIMONY OF R. THOMAS BEACH
ON BEHALF OF
THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Metering	)))))	Rulemaking 20-08-020 (Filed August 27, 2020)

Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar

July 16, 2021

EXECUTIVE SUMMARY

This rebuttal testimony presents the response of the Solar Energy Industries Association (SEIA) and Vote Solar to the opening testimony of the other parties, as served on June 18, 2021. Our opening testimony presented SEIA's and Vote Solar's recommendations for a new Net Energy Metering 3.0 (NEM 3.0) general market tariff for residential customers who install distributed, behind-the-meter solar and solar-plus-storage systems. We do not recommend any change in the NEM program for non-residential, commercial & industrial (C&I) customers.

California is doubling down on its commitment to address climate change, with Governor Newsom's announcement on July 9, 2021 that he has asked this Commission and the California Air Resources Board "to accelerate California's progress toward its nation-leading climate goals," including the possible advancement to 2035 of the state's current goal of carbon neutrality by 2045.[1] The Commission has recognized that these goals are only achievable in a "High DER" future in which all Californians make personal, long-term investments in the distributed energy resources (DERs) – rooftop solar, on-site storage, electric vehicles (EVs), and residential electric heat pumps – that will be needed to reduce carbon pollution in the energy, building, and transportation sectors.[2] This case presents a major opportunity for the Commission to craft policies on DERs that are consistent, measured, and broadly acceptable to the millions of Californians who must invest in these DERs to meet the state's climate goals.

The Commission's decision in this case should begin where all parties agree: California and this Commission have successfully developed and transformed two major markets for DERs – energy efficiency and rooftop solar. On energy efficiency, California's accomplishment of keeping per capita energy use constant for the last 40 years is widely lauded.[3] On rooftop solar, the state has created an industry that consistently installs over 1 GW per year of new renewable generation, has motivated over one million customers to make long-term investments in clean energy using their own capital or credit, and has created major solar companies based in California that have national scope. The state's current resource plan, as well as the statute governing the compensation for customers who install rooftop solar, assumes and requires that California will sustain this growth in distributed solar. If the NEM 3.0 tariff undermines the economics of rooftop solar such that customers no longer are willing to invest, California is

1 See https://www.gov.ca.gov/2021/07/09/governor-newsom-holds-virtual-discussion-with-leading-climate-scientists-on-states-progress-toward-carbon-neutrality/.

2 On June 14, 2021, the Commission issued a proposed new rulemaking (OIR) "to modernize the electric grid for a high distributed energy resources future."

3 This accomplishment is shown in https://www.nrdc.org/sites/default/files/ca-success-story-FS.pdf.

unlikely to be able to replace those lost DERs with utility-scale renewables in a timely fashion. The development process for utility-scale renewables and storage is also uncertain, and a sustainable market for distributed solar and solar-plus-storage provides a valuable and necessary hedge against those uncertainties. Finally, there is strong and growing customer demand for solar-plus-storage systems that can increase the resiliency of the electric system in the face of more frequent and more extreme weather and wildfire events. These paired solar-storage systems also provide much greater value to the grid than solar alone, including much-needed new capacity to meet summer peak demands. But this demand will only be met if these systems remain economic for customers who want to invest in them.

All parties to this case also agree that the compensation for residential customers who install rooftop solar should decrease under the NEM 3.0 tariff that the Commission will develop in this case. The questions for the Commission to decide are how far, and how fast, compensation should be reduced. The record in this case documents what can happen if the compensation is reduced too far, too fast – the experiences in Nevada and Hawaii show that sharp, sudden reductions in compensation can choke off the market almost immediately, leading to market and political turmoil and requiring a significant period of lost time for the market to recover. At this juncture, California cannot afford to repeat those experiences. Unfortunately, as discussed in this rebuttal, a number of parties – the investor-owned utilities (Joint IOUs), the Utility Reform Network (TURN), the Public Advocates Office (PAO), and the Natural Resources Defense Council (NRDC) – have made proposals that clearly would make rooftop solar and solar-paired-storage uneconomic in the state absent large upfront subsidies that are of the same magnitude as the subsidies they decry. Complicating the picture is the evident volatility in the Avoided Cost Calculator (ACC) tool that the Commission uses to evaluate the benefits of all DERs. Under the 2021 ACC avoided costs recently adopted by the Commission in Resolution E-5150, the value of energy efficiency and distributed solar drops by 50% and over 60%, respectively, compared to the 2020 ACC which the Commission adopted a year earlier. Using the 2021 ACC, none of the major proposals in this case appear to be cost-effective in 2023 for non-participating ratepayers or as a resource for the electric system. This volatility in the ACC may continue, as there are significant major issues to be litigated for the 2022 ACC.

In this volatile environment, Vote Solar and SEIA continue to recommend that the Commission make gradual and certain reductions in the compensation for exported power from distributed solar and solar-plus-storage customers. These changes should be calibrated to market uptake – the reductions can occur more quickly if the market remains strong. The reductions should continue until the balance of benefits and costs for non-participating ratepayers is brought into a much closer balance, as measured by the RIM test using the ACC as it is revised periodically. If the ACC avoided costs continue at the low level of the 2021 ACC, the stepdown will go on for longer, and end at a lower level of export compensation. We illustrate in this rebuttal a stepdown trajectory that is consistent with the 2021 ACC.

The NEM 3.0 tariff should provide customers who install solar and solar-plus-storage systems with a reasonable opportunity to earn a return of and on their investment. This rebuttal comments on the paybacks analyses of parties' proposals prepared by the Commission's consultant Energy & Environmental Economics (E3). We make certain changes to the E3 analyses, based on a more reasonable forecast of solar and solar-plus-storage costs and on more accurate calculations of the bill savings for certain proposals. These revisions to the E3 analyses show that the proposals of the Joint IOUs, PAO, and TURN would produce paybacks far too long to be attractive to most customers. Using Energy Information Administration (EIA) data on distributed solar adoption in all 50 states, we show that adopting these proposals would turn California from a leader in solar adoption to a laggard.

This rebuttal discusses the need for DER customers to understand the economics that support their investments and to have a reasonable degree of certainty that those economics will be durable. This includes certainty in the compensation for the power exported from solar and solar-plus-storage systems. The proposals from the Joint IOUs, PAO, TURN, and NRDC would tie export compensation (and, for the Joint IOU proposal, grid access charges) directly to hourly avoided costs from the ACC. Given the evident volatility in ACC values, this will not provide any certainty to support long-term investments in new solar and solar-plus-storage systems.

The NEM 3.0 tariff also should support the state's broader policy goal of encouraging beneficial electrification. This is consistent with the Commission's guiding principles for NEM 3.0 as adopted in D. 21-02-007 and the January 2021 white paper from E3, and is a central focus of the SEIA / Vote Solar proposal. Electrification includes the adoption of multiple types of DERs, including solar, storage, EVs, and heat pumps. SEIA and Vote Solar believe that the foundation of NEM 3.0 for residential participants should be the immediate use of the electrification rates that the Commission has already adopted for several of the IOUs. This would be an important step toward the development of a common rate platform for all types of DERs, and would take a major step toward reducing the impacts of distributed solar on non-participants. The Commission should not adopt the proposal of the Joint IOUs to discriminate against adoption of one particular DER – solar – by requiring customers who adopt solar to use a rate with higher fixed charges that differs significantly from the rate available to those who adopt other types of DERs.

Finally, this rebuttal comments on the Joint IOU proposal for implementing the NEM 3.0 tariff. The larger and more precipitate the changes to the successor tariff, the more difficult the implementation process will be. The transition will be easier if:

- Changes are phased in gradually over time.
- Existing electrification rates are used for NEM 3.0 customers.
- Structural changes in rates are minimized.
- NEM 3.0 compensation does not have to be revised completely each time the ACC is updated.
- The transition to NEM 3.0 does not begin until the IOUs can implement the new program.

Vote Solar and SEIA continue to recommend that NEM 3.0 should be implemented beginning January 1, 2023, assuming that the IOUs' billing systems are ready to bill customers under the new tariff on that date. The NEM 2.0 program should remain in place until that date.

TABLE OF CONTENTS

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Metering	)))))	Rulemaking 20-08-020 (Filed August 27, 2020)

Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar

I. INTRODUCTION AND SCOPE

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Have you previously served testimony in this proceeding?

A: Yes, I served opening testimony on June 18, 2021 in this docket on behalf of Vote Solar and the Solar Energy Industries Association (SEIA). My experience and qualifications are described in the introduction to my direct testimony and in my *curriculum vitae* (CV), which is **Attachment RTB-1** to my direct testimony.

Q: What is the purpose of this rebuttal testimony?

A: My opening testimony, served on June 18, 2021, provided detailed support for the net energy metering “NEM 3.0” successor tariff that SEIA and Vote Solar submitted in this proceeding on March 15, 2021. Vote Solar and SEIA have reviewed the testimony that other parties served on June 18 in support of their proposed NEM 3.0 tariffs, and this rebuttal responds to selected issues in the testimony of certain parties. The focus of this rebuttal is on the proposals that would make severe cuts to the savings available to residential customers who install distributed solar and solar-plus-storage systems in the IOU service territories. These proposals would sharply curtail future installations of these systems. This result would be contrary to both the governing statute, which requires that the successor tariff allow for the sustainable growth of distributed solar,[4] and to the renewable development needed to meet the state's clean energy goals.

Q: Have there been significant developments at the Commission directly related to this proceeding since you served your direct testimony?

A: Yes. On June 24, 2021, the Commission approved Resolution E-5150, adopting a 2021 avoided cost calculator (2021 ACC). The 2021 ACC is dramatically and unexpectedly different – with substantially lower avoided costs – than the 2020 ACC that was the Commission-approved ACC at the time of both the March 15 proposals and the June 18 opening testimony. This rebuttal discusses how the SEIA / Vote Solar NEM 3.0 proposal can be adapted to the 2021 ACC.

Q: The ALJ, in a ruling on July 9, 2021, directed the parties to organize their rebuttal testimony according to the issues listed in the Scoping Memorandum, at pages 2-3.

A: I have followed the requested list of issues in organizing this rebuttal. My opening testimony included an initial section with an overview and guide to how Vote Solar's and SEIA's opening testimony addressed each of the issues in the Scoping Memorandum.

---

[4] See AB 327, specifically P.U. Code Section 2827.1(b)(1): "In developing the standard contract or tariff, the commission shall do all of the following: (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

II. ISSUE 2 – **What information from the Net Energy Metering 2.0 Lookback Study should inform the successor and how should the Commission apply those findings in its consideration?**

A: The NEM 2.0 Lookback Study shows the need for NEM reform – and all parties agree with this need. All parties also agree that the focus of concern is the residential market.[5] That said, there is significant disagreement on the extent of the problem with NEM and on how reform should be approached. This section will discuss the areas where the parties agree, and what is at stake where they do not.

A. Where the Parties Agree

Q: Are there issues in this case that other parties represent as issues of contention, but are not?

A: Yes. Some parties spill a great deal of ink in their opening testimony justifying the need for a change in the current NEM 2.0 tariff in the residential market. For example, the first 60 pages of the Joint IOU testimony are devoted to justifying why there is a need to reform the residential NEM 2.0 tariff. In fact, no party to this case has proposed to keep the current NEM 2.0 tariff in the residential market. All parties agree that there is a need to reduce the bill savings for residential customers who install solar, in the territories of all three investor-owned utilities (IOUs). SEIA and Vote Solar have proposed a significant reduction in bill savings for the NEM 3.0 residential customers of Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E), the two IOUs with the highest rates, to be effective at the outset of the NEM 3.0 program in 2023. Vote Solar and SEIA follow this immediate reduction with a measured stepdown in the export compensation for all three IOUs. This stepdown would occur until there is a more reasonable balance of costs and benefits for all ratepayers, including non-participants.

---

[5] For example, the Joint IOUs devote only 4 pages, out of 212 pages of opening testimony, to the non-residential market.

The parties also agree that one of the reasons for residential NEM reform is to reduce the impact of solar adoption on non-participating ratepayers. The questions before the Commission in this case are not whether to reduce bill savings in the residential market, but how much and how fast to reduce them, what the impact of those reductions on the solar industry in California will be, and what the future rate structure for residential NEM 3.0 customers should be.

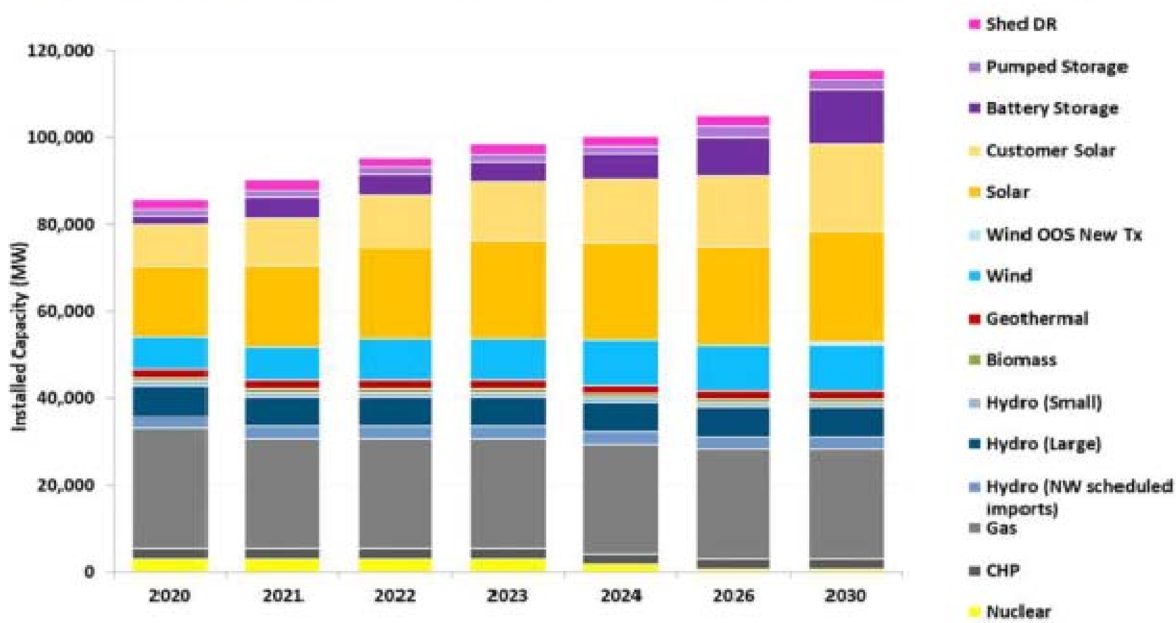
Q: Does the opening testimony show other areas of agreement that you would like to briefly highlight?

A: Yes. There is general agreement among the parties that the NEM program has been a success in developing a robust market for customer-sited, distributed rooftop solar systems. The Joint IOUs' testimony, at pages 8-10, correctly highlights key metrics of this success:

- $72 billion in private investment in renewable energy resources, with two-thirds of existing NEM customers owning their own solar systems.
- 9.4 GW of distributed solar PV generation capacity in the IOU service territories as of the end of February 2021, plus 0.96 GW of capacity in the service territories of the other California electric utilities.
- The economic stimulus of more than 2,000 solar companies operating in California, including 341 manufacturers, 951 installer/developers, and 714 other types of firms. In 2019, California ranked first among the states in terms of overall number of solar jobs (74,255 jobs), with 30% of all solar jobs in the U.S.
- A major contribution to the growth of renewable generation in the state's electric resource mix and the diversification of that portfolio away from fossil fuels.

I also agree with the Joint IOUs that California policies – including NEM 1.0 and 2.0 – have played a central role – along with certain federal policies such as the federal investment tax credit (ITC) – in driving the growth of renewable generation nationally. This growth has produced substantial demand-driven reductions in renewable costs over time.[6] Finally, all of the parties at least appear to support the idea that the state must build on this success and continue the growth of distributed solar into the next decade, as AB 327 requires. For example, this expectation of continued growth is shown in Figure I-4 of the Joint IOU testimony. This expectation also is embodied in the state's current Reference System Portfolio (RSP) resource plan adopted in D. 20-03-028 in the Integrated Resource Planning (IRP) docket. See the light yellow "customer solar" in Figure 3 from D. 20-03-028, shown below.

Figure 3. Cumulative Quantities of All Resources in New 2019-2020 RSP



In the state's current RSP, distributed solar is expected to continue its current level of growth of 1 GW per year for the remainder of the decade, doubling the installed capacity of this resource from 2020 to 2030. This level of growth is included in both of the scenarios for the state's GHG emissions target in 2030 (38 and 46 MT).[7] Also important is the fact that, because this customer solar will be increasingly paired with storage, this

---

[6] See Joint IOU testimony, at pp. 10-13. For the reductions in renewable costs, see Figures 2 and 3 of Attachment RTB-4 of my opening testimony.

[7] See D. 20-03-028, at Table 6 and Figure 3.

growth could add 4.6 GW of new distributed storage by 2030.[8] This will help to address the state's critical need for capacity to serve the net load peak that occurs at sunset on summer evenings. This expectation of sustainable growth in distributed solar is embodied in the statutory foundation for the NEM program, AB 327, specifically P.U. Code Section 2827.1(b)(1).

B. What Is At Stake

Q: Is there a downside to other parties' perceived need to justify reforming the residential NEM tariff, when actually all parties support NEM reform?

A: Yes. The problem is that the justifications for NEM reform – such as the calculations of the NEM "cost shift" – have been greatly exaggerated. My opening testimony showed that the Joint IOUs' cost shift calculations are substantially overstated.[9] The principal cause of the NEM cost shift is the declining costs of renewable generation over time – a decline which all parties should agree has been a good thing for California. I showed that a similar cost shift would exist if today's rooftop solar fleet had been developed with utility-scale renewables instead. There remains a need to reform NEM – because solar costs continue to fall while rates continue to increase, because we must expand the access of low-income customers to local clean energy, and because the state needs to pair solar with storage to improve its value to the system – but not because there are inequities of the magnitude suggested by the Joint IOUs' exaggerated cost shift calculations, with their false and misleading suggestion that these above-market costs could have been avoided if California had taken a different path.

Q: What are the risks to the state from these exaggerated claims of the problems with NEM?

---

8 See SEIA/Vote Solar testimony, at pp. 40-41.

9 *Ibid*., at pp. 62-63 and Attachment RTB-4.

A. The risks are that the Commission will adopt changes in the successor tariff that reduce the compensation for residential solar customers too far, too fast. Section V of this rebuttal shows that many of the proposals in this case would make rooftop solar and solar-plus-storage systems uneconomic in California. Much is at stake were this to happen:

- **Undermine the successful transformation of the solar industry.** The parties agree that California's transformation of the distributed solar industry – in which the state invested billions of dollars of ratepayer money through the California Solar Initiative – has been a success.[10] The state now has an established rooftop solar industry capable of consistently installing over 1 GW per year of new renewable generation, using new sources of private capital and employing tens of thousands of Californians. Sustaining the growth in this industry requires customers to continue to have a reasonable economic opportunity to invest in solar and solar-plus-storage systems and to have confidence that the Commission will not alter significantly the rates and rules that support those investments. The experiences in Hawaii and Nevada when full retail NEM programs were terminated, and compensation reduced dramatically in a short period, show that such precipitate actions can quickly turn off the market. Significant time is needed for the policy changes required to restart the market and to restore the industry's capacity.[11]

- **Place the state's climate goals at risk.** If the Commission were to make distributed solar and solar-plus-storage uneconomic in 2023, it will lose a substantial share of the distributed energy resources (DERs) that are included in the state's RSP. The impact on the DER market might not be recognized by policymakers until after NEM 3.0 is implemented in 2023. After the market slowdown becomes evident, additional time

[10] See Joint IOU testimony, at p. 6: "We have proudly supported California's successful efforts to advance the state's renewable and low-carbon energy goals, including through our implementation of the NEM program, which served an important market development purpose at a specific time."

[11] Appendix 1 to the IOU Proposal is a study of NEM reforms in other states; Figure 1 of that study shows how solar adoption essentially came to a halt in late 2015 / early 2016 in Hawaii and Nevada when those states abruptly terminated their NEM programs.

and Commission process would be needed to implement a correction – either by increasing compensation for DERs or raising the authorized procurement in the IRP to increase utility-scale resources. In the end, valuable time will have been lost, and investments in needed clean generation delayed. The mid-term procurement that the Commission recently authorized for 2023-2026 is consistent with the current RSP, which, as noted above, assumes the continuation of a sustained 1 GW per year build-out of new distributed solar.[12] For example, California could not meet the solar and storage build-out required in the No New DER case that is used for the 2021 ACC and that assumes no further deployment of distributed solar. The No New DER case would require the load-serving entities to bring online 34 GW of new utility-scale renewable resources by 2026, including 18.8 GW of solar, 11.1 GW of storage, 2.8 GW of wind, 0.9 GW of geothermal, and 0.5 GW of pumped storage.[13] The 18.8 GW of utility-scale solar is 150% more than the state's entire existing utility-scale solar fleet, and the 11.1 GW of new storage is about ten times the existing battery storage capacity. The 34 GW of new renewables that would be needed by 2026 exceeds the 30 GW of nameplate capacity from the renewable generation now on the CAISO grid.[14]

SEIA and Vote Solar strongly support the level of mid-term procurement of utility-scale resources that the Commission approved in D. 21-06-035. That said, it will be challenging for the state to bring this large amount of new utility-scale resources online by 2026, given the short time frame for such a substantial amount of new development, growing land use constraints, and unanswered questions about the

---

[12] See D. 21-06-035, at p. 15, finding that the ALJ's proposed mid-term procurement "closely approximates the 18,000 MW of new nameplate capacity by 2026 included in the Reference System Portfolio (RSP) adopted in D.20-03-028." The decision increases the ALJ's recommended amount of procurement in anticipation of moving to the RSP scenario with a 38 MT goal for GHG emissions in 2030, as well as to begin procurement of long-lead-time resources that also were identified in the RSP. The order also acknowledges that the procurement of the long-lead-time resources could slip to 2028. See D. 21-06-035, at pp. 19-20, 25, and 37-38.

[13] From the RESOLVE output file posted by staff in conjunction with draft Resolution E-5150 – "RESOLVE_Results_Viewer_2021-04-02_New46MMTNoDER_NoGas_Clean_Dashboard."

[14] For the existing renewables on the CAISO grid, see, for example, Figure 1 of D. 20-03-028.

availability of adequate transmission to move this power to load centers from the most promising regions for new utility-scale development.[15] The resources required in the No New DER case would not be feasible to procure by 2026. As I discussed in my direct testimony, a robust and growing market for distributed solar and solar-plus-storage provides a valuable and necessary hedge against the uncertainties of the development process for utility-scale renewables.[16]

- **Imperil the Title 24 New Solar Homes mandate.** The Joint IOUs and the Public Advocates Office suggest that the New Solar Home mandate (NSHM) under Title 24, which requires solar on all new home construction in California, will ensure a base of business for the rooftop solar industry.[17] However, the NSHM is also subject to a cost-effectiveness requirement because it is a prescriptive building standard. The cost-effectiveness analysis that the consultant Energy & Environmental Economics (E3) completed for the NSHM in 2018 assumed NEM 2.0 as the compensation structure for new rooftop solar.[18] With NEM 2.0, the benefit-cost ratio for the NSHM was 2-to-1 in most climate zones.[19] However, the E3 NSHM Analysis showed that the NSHM would not be cost-effective in many climate zones, and only marginally cost-effective in others, if the compensation for all solar output were reduced to avoided costs.[20] As discussed later in this testimony, the Joint IOU proposal in this case essentially would do exactly that – reduce compensation for all solar output to the level of avoided costs. Further, the avoided costs for solar that E3 used to justify

---

[15] See the December 1, 2020 comments in R. 20-05-003 of SEIA, Vote Solar, and the Large-scale Solar Association on the Transmission Planning Process (TPP) resource portfolios to be transmitted to the CAISO, as well as the comments of these parties on the subsequent proposed decision. The resource portfolios used for the TPP include substantial amounts of utility-scale projects that are assumed to have Energy Only status, and thus that cannot provide the resource adequacy (RA) capacity that the state needs. Load-serving entities simply have not procured Energy Only projects, due to their RA needs.

[16] SEIA / Vote Solar testimony, at pp. 7-9.

[17] See Joint IOU testimony, at pp. 5 and 13; PAO testimony at p. 5-10.

[18] See E3, *Building Energy Efficiency Measure Proposal to the California Energy Commission for the 2019 Update to the Title 24 Part 6 Building Energy Efficiency Standards – Rooftop Solar PV System* (September 2017), at pp. 34-35. Hereafter, "E3 NSHM Analysis."

[19] *Ibid*., at Tables 15-17.

[20] *Ibid*., at Table 20.

the NSHM were consistent with the 2020 ACC – a 30-year levelized value of 11 to 12 cents per kWh.[21] However, the 2021 ACC has cut these lifecycle avoided costs for solar deeply – reductions of 60% to 66%. If the general market for rooftop solar is found to be uneconomic, then the cost-effectiveness of the NSHM also could be questioned, or an effort could be made to require the use of utility-scale community solar to satisfy this mandate.[22] In addition, as shown in the IOUs' Figure I-4, new homes are just a small fraction of the expected rooftop solar market.[23] PAO's testimony claiming that new homes could support a 444 to 600 MW per year solar market, is unrealistic.[24] PAO is assuming much larger PV systems than the 2 kW-AC systems required for new energy-efficient homes. The E3 NSHM Analysis assumes about 150 MW per year based on 74,000 new homes per year installing systems sized at about 2 kW-AC.[25]

Finally, SEIA and Vote Solar strongly support a significant increase in the financial benefits for low-income customers who adopt solar and solar-plus-storage. The proposal presented by Vote Solar, the Sierra Club, and Grid Alternatives would accomplish this. However, even if the Commission adopts this proposal, and there is accelerated growth among lower-income customers, these new home and low-income

---

[21] The E3 NSHM Analysis used a 30-year present value of solar avoided costs in 2020 of $2.36 per kWh, which is equivalent to 11.5 cents/kWh with no degradation in output, or 12.3 cents/kWh with 0.5%/year degradation (at the 3% discount rate used). See Table 11 and p. 8.

[22] There is an option to use utility-scale community solar projects to satisfy the NSHM. This would require the establishment of a viable community solar program in the IOU service territories, which has not happened to date. See my discussion of the problems with the community solar program in Section V.C below. For the community solar option in the NSHM, see - https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2022-building-energy-efficiency. See the section – 10-115 – COMMUNITY SHARED SOLAR ELECTRIC GENERATION SYSTEM OR COMMUNITY SHARED BATTERY STORAGE SYSTEM COMPLIANCE OPTION FOR ON-SITE SOLAR ELECTRIC GENERATION OR BATTERY STORAGE REQUIREMENTS, at p. 46.

[23] PAO's testimony, at p. 5-10, claiming that new homes could support a 444 to 600 MW per year solar market, is unrealistic. PAO is assuming much larger PV systems than the 2 kW-AC systems required for new energy-efficient homes. The E3 NSHM Analysis assumes about 150 MW per year based on 74,000 new homes per year installing systems sized at about 2 kW-AC. See E3 NSHM Analysis at Table 21 and p. 68.

[24] See PAO testimony, at p. 5-10.

[25] See E3 NSHM Analysis at Table 21 and p. 68.

programs are highly unlikely to offset a substantial drop in the general market for distributed solar.[26]

- **Frustrate customers' desire to use clean resources to improve resiliency.** The Joint IOU testimony documents the high level of customer interest in using solar-plus-storage systems to meet the critical new demand for more resilient electric service in the face of the increasing frequency of wildfires and extreme weather events.[27] However, this interest alone will not guarantee the success of the solar-plus-storage market. Resilient electric service requires a source of on-site generation – solar – to charge and re-charge the battery. A successor tariff that undermines the economics of solar adoption also will limit the solar-plus-storage market. Moreover, residential customers have competing options for resilient electric service – principally, portable gasoline generators – whose sales also have boomed during recent fire seasons in California,[28] notwithstanding the air, noise, and carbon pollution, and the safety and fire risks, from these readily-available units.[29]

- **Discourage adoption of other DERs requiring customers' long-term investments.** The one million California utility customers who have invested in rooftop solar are both a key market for newer types of DERs as well as key influencers for their friends

[26] The Vote Solar, the Sierra Club, and Grid Alternatives proposal would apply to CARE customers and non-CARE customers with incomes below 120% of the area median income (AMI). This comprises about 40% of utility customers. Solar adoption among these lower income customers has lagged adoption by customers with incomes higher than 120% of AMI, but making up this deficit will not result in a major overall increase in the solar market. See NEM 2.0 Lookback study, at Figure 3-6.

[27] See Joint IOU testimony, at pp. 43-44.

[28] See https://fortune.com/2019/11/08/california-power-outages-small-business-generators/.

[29] For the wildfire risks, see, for example, https://www.sfchronicle.com/california-wildfires/article/During-PG-E-outages-generators-caused-fires-14833601.php. Portable gasoline generators cause about 70 annual deaths in the U.S., and can be a significant fie hazard. See U.S. Consumer Product Safety Commission, "Incidents, Deaths, and In-Depth Investigations Associated with Non-Fire Carbon Monoxide from Engine-Driven Generators and Other Engine-Driven Tools, 2005-2016," at p. 5, available at https://www.cpsc.gov/s3fs-public/Non-Fire-Carbon-Monoxide-from-Engine-Driven-Generators-2005-2016-June%202017.pdf?FL5ZFHu050hLH_NGRwJtpM2EE4JHeveV. The health risks of widespread use of fossil back-up generators (BUGs) has long been known. See https://www.edf.org/sites/default/files/2272_BUGsreport_0.pdf and

and neighbors who are considering DER investments. A sudden and adverse change in the NEM program – even if existing solar customers are not impacted – will shape all customers' willingness to invest not only in solar but also in other types of DERs, including storage, EVs, and heat pumps. Customers will notice if their early-adopter neighbors with NEM 1.0 or 2.0 systems are still saving money with solar, but that opportunity is no longer available to them on reasonable terms. Customers' willingness to continue to invest in all types of DERs will depend on the public perception of the equity, stability, and reasonableness of the Commission policies that underpin those investments, whether it is the NEM program or the design of off-peak electric rates that allows EV customers to save money compared to liquid fuels.

- **Call into question California's leadership on climate and DER technology.** A serious erosion of the state's support for DERs could set a national precedent that slows the U.S. response and adaptation to climate change. The state also has benefitted from its leadership in developing new DER technologies (such as rooftop solar and EVs) and in transforming the markets for those technologies. The loss of that perceived leadership would have long-term adverse consequences for the state's economy.

Given what is at stake in this case, the parties that are proposing the greatest changes bear the greatest burden of showing that their proposals are not too risky for California, and do not jeopardize the achievement of the state's long-term carbon reduction goals.

---

https://ww2.arb.ca.gov/resources/documents/use-back-engines-electricity-generation-during-public-safety-power-shutoff.

IV. ISSUE 3 – **What method should the Commission use to analyze the program elements identified in Issue 4 and the resulting proposals, while ensuring the proposals comply with the guiding principles?**

A: SEIA and Vote Solar continue to recommend use of the full suite of cost-effectiveness tests in the *California Standard Practice Manual* (*SPM*), with a long-term, lifecycle analysis and a comprehensive list of benefits and costs. This includes new benefits such as resiliency. The major new methodological development since opening testimony has been the Commission's adoption of the 2021 Avoided Cost Calculator (2021 ACC).

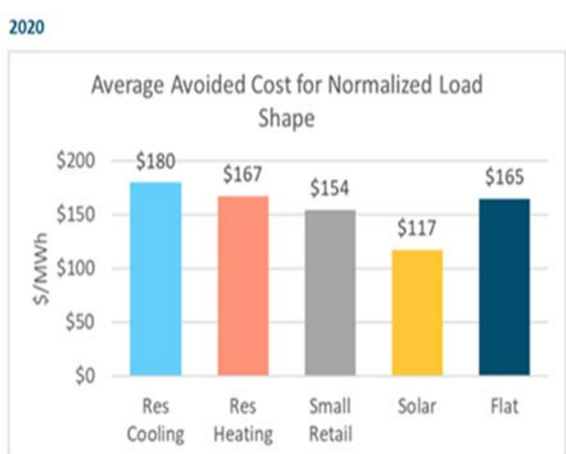
A. The Impact of the 2021 ACC

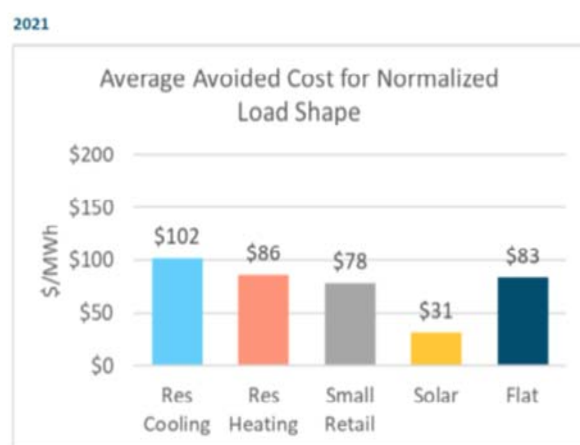
Q: On June 24, 2021, the Commission adopted the 2021 ACC in Resolution E-5150. Vote Solar and SEIA submitted extensive comments opposing the adoption of the 2021 ACC on both process and substantive grounds. Please discuss SEIA and Vote Solar's position on the use of the 2021 ACC in this proceeding.

A: Vote Solar and SEIA disagree strongly with the substance of the 2021 ACC adopted in Resolution E-5150 and with the process used to develop it, for the reasons stated in our comments on draft Resolution E-5150. That said, Vote Solar and SEIA recognize that the Commission has made its decision, and this case is not the venue for challenging the Resolution E-5150 or for litigating ACC issues. Vote Solar and SEIA will be filing an application for rehearing of Resolution E-5150 based on the legal and factual errors in the resolution, and, if necessary, pursuing remedies in California appellate courts. SEIA and Vote Solar also intend to pursue major changes to the 2021 ACC in the 2022 major update to the ACC in the successor proceeding to R. 14-10-003. For the purposes of this case, SEIA and Vote Solar accept Resolution E-5150 as issued. I discuss below the implications for this case of the changes from the 2020 ACC to the 2021 ACC, how those changes should impact the Commission's consideration of the parties' proposals, and how the 2021 ACC affects the SEIA / Vote Solar proposal.

Q: How does the adoption of the 2021 ACC impact the value of DERs, compared to the 2020 ACC?

A: The 2021 ACC dramatically reduces the value of any DER that reduces or shifts loads. This includes energy efficiency and demand response as well as solar and storage. Reproduced below is Figure 4 from the documentation for the 2021 ACC, showing the single-year change in the value of selected DERs in 2030, from the 2020 ACC (first graph) to the 2021 ACC (second graph). The value of solar PV in 2030 drops by 74%, from 11.7 cents per kWh to 3.1 cents per kWh. Using the detailed hourly outputs in the 2021 ACC, we have calculated that similar declines would occur in the value of solar over longer time horizons corresponding to the lifecycle of these resources; for example, the 25-year levelized value of solar from 2021-2045 would drop by 60% to 66%.[30] The 25-year levelized value of solar-plus-storage resources would decline by 30% to 36%. The value of energy efficiency measures also would drop substantially, on the order of a 50% reduction. This dramatic drop in the value of these DERs could have significant impacts on the markets for DERs in California.





Q: How would this substantial drop impact the proposals submitted in this case?

---

30 The decline would be at the upper end of this range for PG&E and SDG&E, and at the lower end for SCE.

A: For those NEM 3.0 proposals that use ACC values directly, the use of the 2021 ACC results in a substantial reduction in the bill savings available to customers considering investments in either solar or solar-plus-storage systems under NEM 3.0, compared to the March 15 proposals that were based on the 2020 ACC. For example, the Joint IOU proposal would use ACC values directly as compensation for exported power. Exports typically are one-half of the output of a residential solar system. The IOUs also proposed grid "benefit" or grid access charges (GACs) that they allege are needed to recover utility system costs for the portion of the solar output that serves the customer's onsite load (even though that power never touches or uses the utility system). In the calculation of the IOU GACs, solar customers are credited for avoided costs using the ACC. As a result of the lower 2021 ACC values, the IOUs' proposed GACs increase compared to their original GACs that used the higher 2020 ACC values. **Tables 1 and 2** shows the changes in the IOUs' off-peak export rates and their GACs from their March 15 proposal (which used the 2020 ACC) to their June 18 testimony (which assumed that the 2021 ACC would be approved). In addition, the IOUs appear to have told E3 that their proposed GACs (which are calculated using 2021 rates and 2022 avoided costs) will be the same in both 2023 and 2030. However, the 2021 ACC has different (and sometimes lower) solar-weighted avoided costs in 2023 and 2030 than in 2022, which would produce different (and often higher) GACs in 2023 and 2030 than what E3 has used.

Table 1 – *Change in IOU Off-peak Export Rates – 2020 ACC to 2021 ACC ($/kWh)*

Source	Season	TOE Period	PG&E	SDG&E	SCE
IOU Proposal 2020 ACC	Summer	Off-Peak	0.06	0.07	0.07
		Super Off-Peak	n/a	0.06	n/a
	Winter	Off-Peak	0.05	0.05	0.06
		Super Off-Peak	n/a	0.05	0.05
IOU Testimony 2021 ACC	Summer	Off-Peak	0.051	0.058	0.063
		Super Off-Peak	n/a	0.060	n/a
	Winter	Off-Peak	0.026	0.029	0.061
		Super Off-Peak	n/a	0.028	0.034
Percent Change	Summer	Off-Peak	-15%	-17%	-10%
		Super Off-Peak	n/a	0%	n/a
	Winter	Off-Peak	-48%	-42%	2%
		Super Off-Peak	n/a	-44%	-32%

Table 2 – *Change in proposed GACs – 2020 ACC to 2021 ACC ($/kW-month)*[31]

Source	Units	PG&E	SDG&E	SCE
IOU Proposal 2020 ACC	$/kW-DC	10.93	11.09	7.39
	$/kW-AC	12.86	13.05	8.69
IOU Testimony 2021 ACC	$/kW-AC	14.13	14.06	10.24
% Change	% change in $/kW-AC	+10%	+8%	+18%

Q: How would this change impact a typical solar customer's bill savings?

A: The Joint IOUs are proposing to update both their export rates and GACs every year, when the ACC is revised and as their retail rates change. A customer who decided to invest in solar under the IOU proposal might have made the investment based on the 2020 ACC. But then a year later, with the adoption of the 2021 ACC, the customer would discover that the GACs had increased by 8% to 18% and the off-peak export rates decreased by 32% to 48%. The one-year change from the 2020 to 2021 ACC reduces PG&E's proposed bill savings for a typical residential solar customer from 8.6 cents per

31 Assumes 0.85 kW-AC per kW-DC. The Joint IOU proposal presented GBCs in $/kW-DC. The Joint IOU testimony presented GBCs in $/kW-AC. Capacity factors used in their calculations assumed Verdant Lookback study capacity factors converted to AC, assuming a 0.85 AC-to-DC ratio (i.e. a 1.18 inverter loading ratio).

kWh to 6.8 cents per kWh[32] – a drop of 21% in just one year. If the customer could do a lifecycle calculation of the expected bill savings (which would be very complicated to do given how the ACC impacts the GACs), the customer would learn that the 25-year lifecycle value of their investment in renewable generation had dropped in one year by far more – a decrease of up to two-thirds.

Q: How would these sharp drops in bill savings impact a customer's expectation for the payback on their solar system?

A: The simplest measure of payback period is the investment cost divided by the first-year bill savings. These sharp declines in first-year bill savings would produce a corresponding increase in customers' estimates of the simple payback period to recover their investments. The 21% drop in first-year bill savings for the PG&E solar customer would extend their simple payback by 27%, so a 10-year payback would increase to almost 13 years.

Q: Was there also a major change in the ACC values from the 2019 to the 2020 ACC, as a result of the 2020 major update to the ACC?

A; Yes, there was. This change was an increase in the value of DERs. This change was the result of the major methodological change that was implemented in 2020 – the use of utility-scale renewables and storage as the avoided resource, instead of the gas-fired combined cycles and combustion turbines used as the marginal resource in all ACCs through 2019. The Commission made the major changes in the 2020 ACC precisely because the ACCs up to 2019 were fossil-based, not integrated with the IRP, and no longer reflected the reality of California's electric system. The IRP modeling extended to 2045, and showed the significant cost challenge of decarbonizing the California electric system by 2045. The Commission adopted the 2020 ACC in D. 20-04-010 after a fully-

[32] These bill savings calculations use our bill savings model for PG&E. The E3 model of the Joint IOU proposal computes even lower bill savings for a PG&E solar customer, about 5.8 cents per kWh. See Table 7.

litigated proceeding, and implemented that order in Resolution E-5077. No party sought rehearing or modification of these orders.

Q: Given this experience with the volatility in the ACC over the last several years, do you anticipate that there will continue to be active litigation over the ACC in the future?

A: Yes. First, there are the legal issues in the upcoming application for rehearing of Resolution E-5150. Beyond that, both Resolution E-5150 and other current CPUC proceedings that impact the ACC include significant open issues that have the potential to cause volatility in future ACC updates. These include:

- **Natural gas rate escalation.** The 2021 ACC includes an input assumption that the long-term escalation in gas transportation rates will be at the general inflation rate of 2.2% per year. But gas transportation rates have been rising far faster than inflation since 2010, and several studies have shown that these rates will continue to escalate much faster than inflation as gas throughput declines to meet carbon reduction goals.[33] In Resolution E-5077 adopting the 2020 ACC, the Commission stated that "[w]e agree that this issue deserves more scrutiny." Resolution E-5150 deferred this issue to the 2022 major update of the ACC.

- Several issues that will impact the ACC are under litigation in A. 19-11-019, PG&E's GRC Phase 2 case. This includes **the forecast of utility-scale battery costs** and **avoided transmission costs**.

- **Changes in future IRP modeling.** Resolution E-5150 made clear that an ACC update does not require a fully-vetted and approved IRP RSP or PSP, but can be updated based on a recent run of the IRP models that the Commission approves through the resolution process with a 20-day comment period.[34] This opens the door

[33] See E3, "Draft Results: Future of Natural Gas Distribution in California," presented at the CEC Staff Workshop for CEC PIER-16-011 on June 6, 2019. Available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf. Also see E3's work as technical support for the Gridworks study releasedin 2019, *California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller*, available at at https://gridworks.org/initiatives/cagas-system-transition/.

[34] See Resolution E-5150, at p. 24: "D.20-04-010 does not specify that only an RSP that is adopted in a CPUC decision may be used in the ACC…. we note that if we were to use only an RSP that has been adopted by a CPUC Decision, it would be difficult to update the ACC annually, as the IRP proceeding does not adopt a new RSP each year."

to litigation of IRP modeling issues in the ACC update process. However, the resolution also acknowledges that whether a Commission-approved IRP plan should be used for the ACC is "a significant question" and the resolution includes this as an issue in the 2022 ACC major update proceeding.[35]

- Re-visiting the **SERVM modeling changes** that were not subject to in-depth review by all parties in the minor 2021 update.[36]

These open issues underscore the potential for continued volatility in the ACC.

B. The Role of the ACC Going Forward

Q: Given the major swings in DER valuation that have resulted from recent ACC updates, as well as the outstanding issues for future updates, what do you conclude about the usefulness of the ACC as the basis for DER valuation or compensation?

A: I conclude that the ACC, as it has been implemented by the Commission over the last several years, is not a stable or useful tool for valuing DERs, and would be particularly inappropriate to use directly in DER compensation. There are three principal reasons for this conclusion.

First, and most important, customers need to know the value proposition when they make a long-term investment in a solar or solar-plus-storage system. If the ACC is used directly to set export rates, it will impact the compensation for about 50% of the output of a typical residential solar system. If the ACC is used to set a GAC – as the IOUs have proposed – then the ACC will impact compensation for 100% of the output of a residential system. Customers will not invest in such systems if the value of the service they provide to the grid swings so significantly and so unexpectedly in just one year. As noted above, under the Joint IOU proposal, the change from the 2020 to 2021 ACC immediately reduces PG&E's proposed bill savings for residential solar by 21%. The long-term value of the system would drop by two-thirds. A customer who had just made

[35] *Ibid*.

a major investment in solar in reliance on the 2020 ACC values would not be happy to experience this.

Second, if NEM 3.0 compensation is based directly on the ACC, solar companies that install DERs will not be able to provide customers with any assurance as to their future economics. Nor will lenders have confidence that solar customers will save enough money to pay back the loans used to finance systems, and today's robust market for solar financing in California may dry up. There will not be stability in California's DER market if the market rises and falls based on the results of litigating the annual ACC update. Larger solar companies with multi-state footprints perhaps could shift to other markets that are not subject to such boom & bust cycles. However, many solar installation companies are local and only operate in California. These companies may not survive such swings.

Third, based on the experience of the 2020 and 2021 ACC updates, the annual ACC updates, whether major or minor, may become contentious battles over modeling, particularly if ACC avoided costs are used directly to compensate NEM 3.0 customers (as well as existing NEM 1.0 and 2.0 customers as they roll off their 20-year legacy periods). In addition, litigation on modeling issues that impact DER valuation will make IRP proceedings more contentious, as DER advocates may have little choice but to continuously litigate IRP modeling issues that directly impact DER valuation and compensation through the ACC.

Q: Mr. Beach, do you have experience with generation resources whose compensation and long-term viability depended on administratively-determined avoided costs?

A: Yes, I do. I began my career in the energy industry working at the Commission in 1981 on the staff team responsible for the implementation of PURPA in California. After I

[36] Information on the SERVM modeling changes were not provided to parties until May 19, 2024, five days before comments on draft Resolution E-5150 were due.

entered private practice in 1989, for the next 25 years I represented the full range of qualifying facilities (QF) in a myriad of Commission avoided cost proceedings that set administrative prices for QFs. This included repeated litigation over marginal heat rates, avoided natural gas costs to fuel the marginal generator, avoided line losses, avoided variable O&M costs, and avoided capacity costs. This continual litigation was extraordinarily resource-intensive and contentious, even though typically it was limited to setting ongoing energy payments to existing, already-built QFs. Most of the development of new QFs in California occurred in the 1980s, so the continuous litigation after the 1980s did not result in new QF construction.

Continual litigation over ACC issues, if they are used directly for NEM compensation, is particularly likely given the large amount of existing NEM systems that ultimately would be involved as NEM 1.0 and 2.0 customers end their legacy periods (a total of at least 10 GW, similar to the 10 GW of QF capacity developed in the 1980s). Because the ACC also would impact directly the compensation for new customer-sited solar, the pace of future development of this resource would be at issue in each ACC update proceeding. As noted above, the IRP expects the industry to build another 10+ GW of distributed solar by 2030, and this could and should be accompanied by 4 to 5 GW of new distributed storage.[37]

Q: Given the evident volatility in the ACC, and the problems you have cited with the direct use of the ACC to compensate NEM 3.0 customers, how do you recommend that the ACC should be used?

A: First, for the reasons discussed above, the Commission should reject the direct use of ACC values for compensating NEM 3.0 customers, either for exports to the grid or for the power used BTM. Thus, the Commission should not adopt the following parties' proposals for direct use of the ACC:

- Joint IOU proposal – both export rates and "Grid Benefit Charges" (GBCs) are linked directly to current ACC values.
- PAO proposal – export rates are based on 1-year ACC values.
- NRDC proposal – export rates use 3-year forward ACC values.
- TURN proposal – export rates would be set at the current ACC value, except the avoided energy component would use actual CAISO market prices. There would also be an option of locking-in 5-year or 10-year ACC values.

Second, the direct use of the ACC values should be limited to net surplus compensation, which has been priced at current short-run avoided costs for the last decade without controversy. Net surplus compensation covers only the small amount of distributed solar output that may exceed the customer's annual usage, due to changes in that usage or, as SEIA and Vote Solar have proposed, the oversizing of the solar system in anticipation of load growth.

Third, the ACC should retain its traditional role as the source of the ratepayer benefits of DER programs, for use in the SPM benefit-cost tests that measure the overall cost-effectiveness of DER programs.

C. Adapting the Vote Solar / SEIA Proposal to the 2021 ACC

Q: Your proposal used the 2020 ACC in its SPM benefit-cost tests, as that was the Commission-approved ACC at that time. As you have observed, the 2021 ACC results in a significant drop in the avoided cost value of the output from solar and solar-plus-storage systems. How would the SEIA and Vote Solar proposal change to use the 2021 ACC?

A: The role of the ACC in the SEIA / Vote Solar proposal is to determine when to end the stepdown in export compensation for residential customers, and at what level. Based on

[37] 10 GW of distributed solar will produce about 16,600 GWh of power at a 19% capacity factor. If the value of this power is as little as $50 per MWh or as high as $150 per MWh, the amount of annual revenue at stake in the annual ACC litigation would be as much as $1.7 billion.

the 2020 ACC, our opening testimony projected an end to the stepdown in 2027. But if avoided costs remain at the lower level of the 2021 ACC, the stepdown in export rates for residential customers would need to be extended for several more years, with lower final export percentages. Based on the 2021 ACC, we estimate that an additional three years of export rate stepdowns will be necessary, and we propose that each added step would be a further 10% reduction in the export percentage for each annual tranche of capacity. Thus, the export rate stepdowns would continue until 2030, when 90% solar-plus-storage systems are expected. Each tranche of capacity would continue to be a total of 780 MW across the three IOUs, as shown in Table 4 of our March 15 proposal. The stepdown schedule for the SEIA / Vote Solar proposal using the 2021 ACC is shown in **Table 3**. Then **Figures 1 to 3** show the benefits and costs of residential distributed solar and solar-plus-storage systems under the RIM test for this revised proposal, from 2023 through 2030, again using the 2021 ACC. These figures are the revised versions of Figures 2 to 4 in our March 15 proposal, which used the 2020 ACC.

Table 3: *Stepdowns in Export Percentages, using the 2021 ACC*

Step	**Export Percentages**		***Expected Year for Each Step***
	PG&E and SDG&E	**SCE**	
1	Electrification rate	Electrification rate	*2023*
2	95%	95%	*2024*
3	85%	90%	*2025*
4	70%	85%	*2026*
5	50%	75%	*2027*
6	40%	65%	*2028*
7	30%	55%	*2029*
8	20%	45%	*2030*

revenue at stake in the annual ACC litigation would be as much as $1.7 billion.

Figure 1

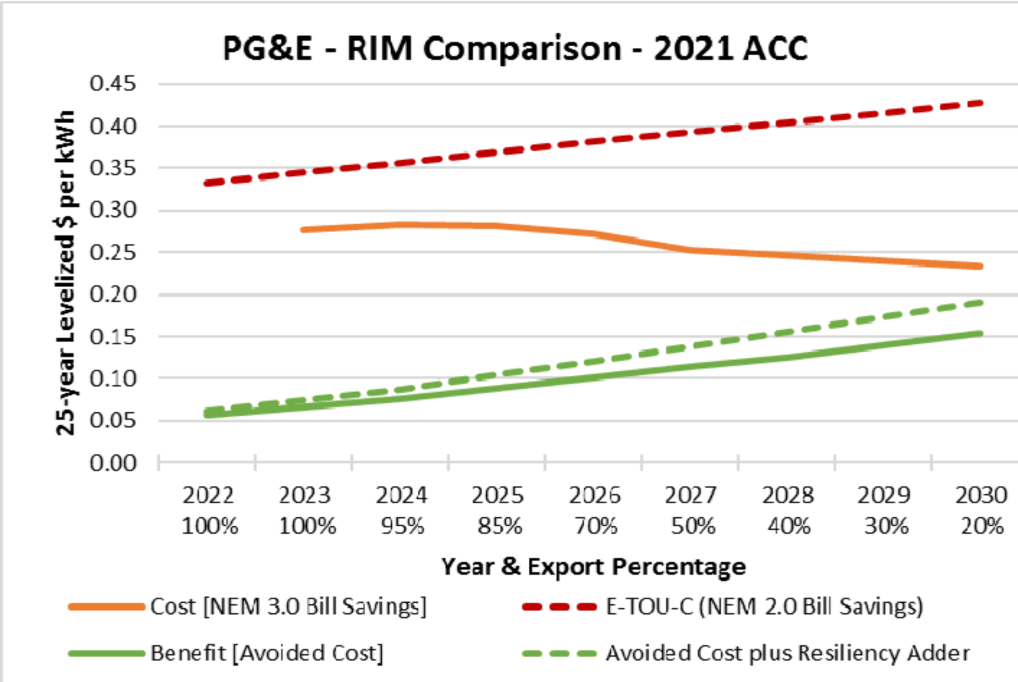


Figure 2

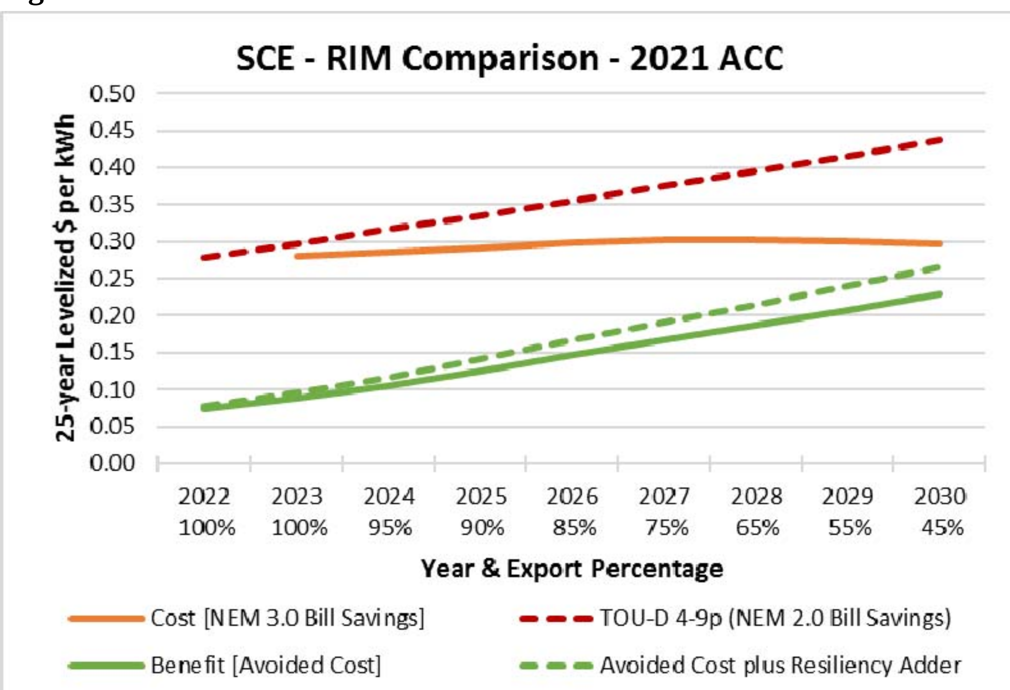
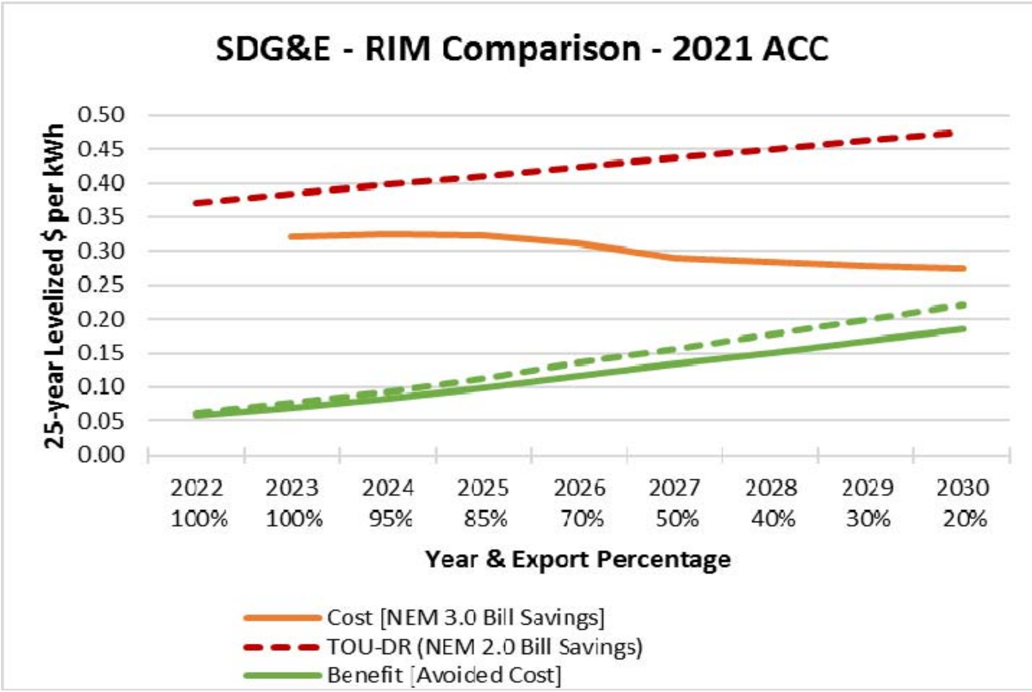


Figure 3



Given the evident volatility in the ACC, the prospect of future litigation over the ACC, and the likelihood that the rate design for residential electrification rates will continue to evolve, the Commission should re-evaluate periodically – in conjunction with the biennial major updates to the ACC – when the stepdown in export rates should end, and at what level. The first re-evaluation of the trajectory should occur no later than the 2024 major ACC update.

Q: Figure 1 to 3 show that the benefits do not quite equal the costs for the three IOUs in 2030, at the end of your stepdown in export rates. Please comment.

A: Figure 1 to 3 show that our proposal gradually reduces the cost shift to non-participating ratepayers of the IOUs, such that by 2030 over 80% of the cost shift has been mitigated. The Commission should find this acceptable, for several reasons.

First, as discussed in my direct testimony, a significant portion – perhaps all – of the existing NEM cost shift is due to the declining costs of renewables, and would have existed even if utility-scale solar had been developed instead of rooftop. Resolution E-5150 justifies the large drop in ACC values as due to forecasts of continued declines in the costs for utility-scale renewables and storage.[38] If true, this indicates that these above-market costs will continue, regardless of whether the state develops utility-scale or distributed resources. For example, the large quantity of utility-scale resources that California must develop immediately – the 3.300 MW of near-term and 11,500 MW of mid-term resources approved in D. 19-11-016 and D. 21-06-035 – could be less expensive if they were delayed, but the state needs those resources now.

Second, there are significant societal benefits from the continued deployment of distributed solar under NEM 3.0. These additional benefits – $3.8 billion per year using the 2020 ACC, $1.7 billion per year using the 2021 ACC – are substantially larger than the cost shifts shown in Figures 1 to 3 using the 2021 ACC, which average $1.0 billion per year from 2023 to 2030. The Commission should weigh these societal benefits in determining the balance of equities for non-participating ratepayers.

Third, only one of the proposals advanced in this case passes the RIM test by 2030, according to the analysis that E3 provided to parties on June 16, 2021. Achieving non-CARE solar-plus-storage RIM scores above 0.80 in 2030 for the three IOUs for general market (non-CARE) residential solar-plus-storage customers would be one of the highest sets of RIM scores among all of the proposals.[39] Furthermore, a stringent application of the RIM test is inappropriate given that the deployment of DERs of all types is necessary

[38] See Resolution E-5150, at p. 30: "These modeling changes… along with the updated data inputs (particularly the decreases in solar and storage costs), resulted in much lower 2021 avoided cost values." Also see the 2021 ACC Documentation prepared by E3, at p. 2, citing the 2021 ACC's "[l]ower GHG value from IRP RESOLVE modeling, due primarily to lower costs for utility scale solar and energy storage."

[39] See E3 June 16 Analysis, at Table 9. The only proposal that has a score of 1.0 or above on the RIM test for all three IOU is the CARE proposal to pay avoided energy costs to NEM generators.

to reach the state's climate goals and will benefit ratepayers overall by increasing electric loads. I discussed this point at length in my opening testimony.[40]

Q: E3's analysis of the SEIA / Vote Solar proposal for solar-plus-storage systems in 2030, using the 2021 ACC, shows RIM scores of 0.26 to 0.46.[41] These are much lower than shown in Figures 1 to 3. Have you analyzed this discrepancy?

A: Yes, I have. First, SEIA and Vote Solar are now projecting that a further stepdown in export rates from 2028 to 2030 may be needed, such that the PG&E and SDG&E export rates in 2030 would be 20% of retail, with SCE's export rates at 45% of retail. This will increase the 2023 and 2030 RIM scores. There are also other important differences in our analysis compared to E3's work:

- **Rate escalation and initial rates.** We calculated 2021 bill savings and then used a different escalation in retail rates than E3 (3.5% in 2021-2030 and 2.2% from 2031-2050 [i.e. general inflation in the years after 2030]). E3 assumes that rates increase from June 2021 at 4.0% per year through 2049. As discussed further below, 4.0% annual rate escalation over the next 30 years is not a reasonable or sustainable assumption, and is inconsistent with the 2021 ACC. We also started with January 2021 rates, as those are consistent with applying a full year of rate escalation to determine the next year's (2022) rates.
- **Starting rates.** The E3 analysis calculates the customer's pre-solar costs assuming service on the residential default TOU rate, not on the rate on which solar customers are required to take service. As a result, a significant portion of bill savings can result not from solar adoption, but from the switch to a more favorable rate schedule. This is particularly true for SDG&E: E3 shows much shorter paybacks for SDG&E's proposed E-DER rate than for the other two IOUs due to the benefits of switching to E-DER. We assume that the IOUs already

---

40 See SEIA / Vote Solar testimony, at pp. 46-48. Also see pages 30-31 of the SEIA / Vote Solar NEM 3.0 proposal.

41 E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020: A Comparative Analysis* (June 16, 2021), at Table 9. Hereafter, "E3 June 16 Analysis."

have (or will soon have in the case of SDG&E) electrification rates that customers can choose in lieu of the default residential TOU rate. Analyses of bill savings from NEM 3.0 should focus only on solar adoption, and should not include savings that result from the ability of customers to arbitrage different rate designs. Therefore, calculations of bill savings should assume the same rate both before and after a solar or solar-plus-storage system is adopted.

- **Degradation.** We used degradation of solar output of 1.4% per year, consistent with the NEM 2.0 Lookback study. E3 assumes no degradation in solar output, even over 20 years. The decline in solar output over time reduces both future bill savings and avoided costs.
- **Solar and solar-plus-storage profiles.** E3 chooses inland load and solar profiles that do not represent the coastal areas where most of the state's population resides. The inland climate zones also have much larger baseline allowances.
- **Application of the minimum bill.** The $10 per month minimum bill for solar customers applies only to the distribution portion of the rate. That is how we model the minimum bill in our bill savings calculations. E3 applies the minimum bill to the entire rate, which understates the impact of the minimum bill to reduce bill savings.
- **Use of resiliency benefits.** My analysis includes the added resiliency benefits of solar-plus-storage that I quantified in Attachment B of the SEIA / Vote Solar proposal.

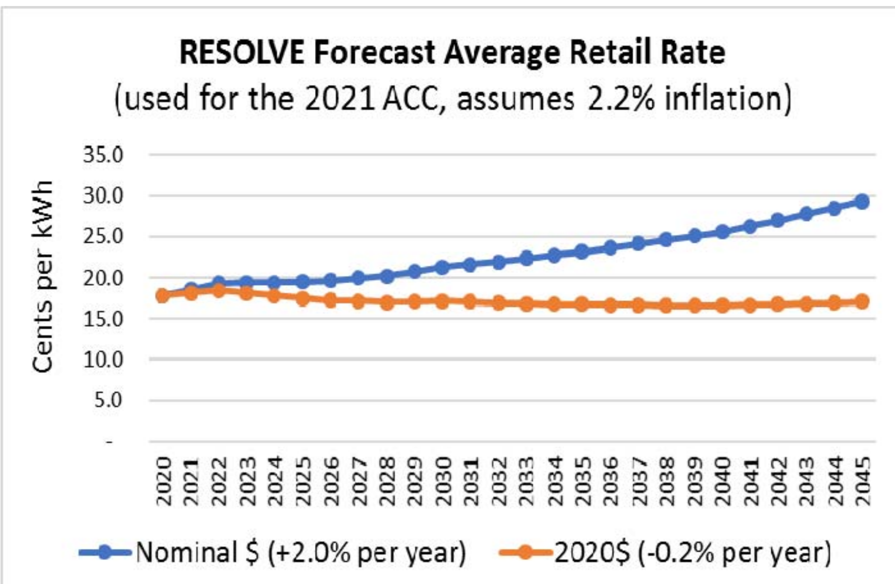
The cumulative impact of these changes raises the RIM scores of the SEIA / Vote Solar proposal to the levels shown in Figures 1 to 3.

Q: Please discuss in more detail the rate escalation issue.

A: SEIA and Vote Solar have recommended and used rate escalation of 3.5% per year from 2021 to 2030, then inflation (2.2% per year) thereafter. A long-term assumption that retail rates in California will escalate at 4% per year is neither reasonable nor sustainable. For example, today's 23 cents per kWh average residential retail rate in California (see

EIA data for April 2021) would escalate to 33 cents/kWh by 2030 and to 70 cents/kWh by 2050. This is not a realistic assumption for an electrifying world in which the use of electricity – in particular, off-peak power – continues to grow strongly, is competitive with fossil fuels, and assumes a much larger percentage of California's primary energy use. It is also inconsistent with the 2021 ACC, which models a world in which the marginal cost of adding new electric resources is low. The RESOLVE model run used in the 2021 ACC shows average retail rates in California escalating at 2.0% per year from 2020 to 2045, which is 0.2% per year <u>below</u> the inflation rate from 2020 to 2045. See **Figure 4**. The focus of the RESOLVE model is limited to utility-scale generation and transmission costs, but those comprise about one-half of the electric revenue requirement.

Figure 4

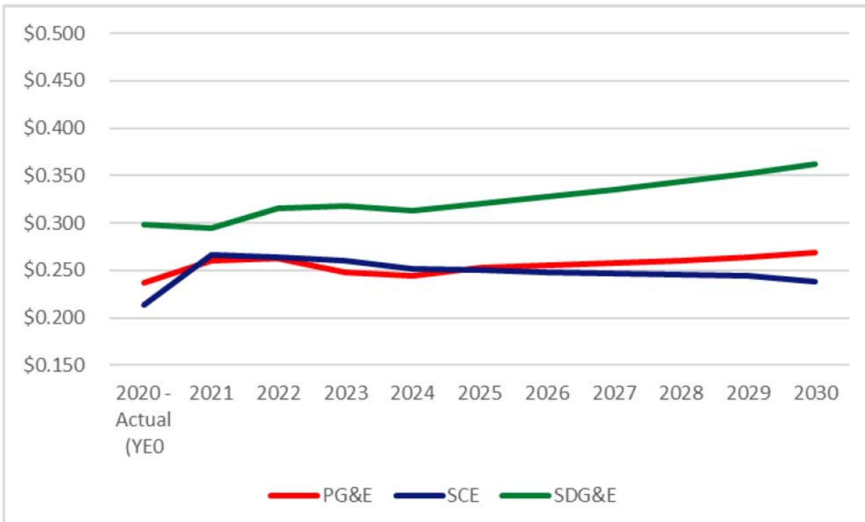


The rate forecast that Commission staff prepared for the February 24, 2021 *en banc* hearing on electric rates shows overall rates – including distribution, wildfire, and other costs – increasing at close to the inflation rate from 2021 to 2030 for PG&E and SCE, with only SDG&E experiencing rate escalation significantly higher than inflation.[42] Here

[42] See CPUC Staff, *Utility Costs and Affordability of the Grid of the Future: An Evaluation Of Electric Costs, Rates And Equity Issues Pursuant To P.U. Code Section 913.1* (February 2021), at Figures ES-1 to ES-3, and pp. 48-56.

is Figure 26 from that report, showing the residential rate forecast in constant 2019 dollars. The Commission staff report for the rates *en banc* also discusses the potential for more rapid electrification to produce incremental load growth at a cost that further reduces future rates.[43] For these reasons, we believe that our rate escalation assumption (3.5% per year in 2021-2030 and 2.2% per year [i.e. general inflation] from 2031-2050) is more realistic and more consistent with the 2021 ACC and with the state's ever-more-aggressive electrification goals than 4% per year for the next 30 years.

Figure 26: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates ($2019/kWh), Baseline Scenario



Q: Does the adoption of the 2021 ACC impact the calculation of the societal benefits that you presented in your opening testimony?

A: Yes, because the modeling for the 2021 ACC has lower marginal GHG emissions than the 2020 ACC. **Table 4** below is a revised version of Table 2 from my opening testimony, now using the marginal emissions from the 2021 ACC.

43 *Ibid*., at pp. 83-85: "The proportional increase in electricity sales is greater than the increase in costs" [in the High Electrification scenario].

Table 4: *Societal Benefits (25-year Levelized $Millions per year), using 2021 ACC*

Benefit	**NEM 1.0**	**NEM 2.0**	**NEM 3.0**
Period analyzed	*2021 to 2045*		*2023 to 2047*
Methane Leakage	$69	$178	$613
SCC (above ACC)	$422	$820	$715
Health Benefits	$62	$124	$116
Local Jobs	-	$117	$206
Land Use	$13	$27	$30
Total	**$566**	**$1,266**	**$1,681**

V. ISSUE 4 – **What program elements or specific features should the Commission include in a successor to the current net energy metering tariff?**

A: There are three essential elements to the successor NEM tariff. First, there must be a strong **equity & inclusion element** designed to increase the ability of low-income Californians to access solar and solar-plus-storage systems. Second, to address the balance between participating and non-participating ratepayers, the Commission should adopt **a gradual step-down in the compensation for exports to the grid from distributed solar**. Third, the general market tariff must support and be consistent with the state's efforts to **promote electrification** as a key strategy to meet California's climate goals.

A: The Equity & Inclusion Element

Q: Do SEIA and Vote Solar continue to support the low-income tariff proposal of Vote Solar, Grid Alternative, and the Sierra Club?

A: Yes. Stephen Campbell of Grid Alternatives is presenting rebuttal testimony on the design of an equitable and effective successor tariff for low-income customers.

B. Balancing Sustainable Growth and Mitigation of Non-Participant Impacts

1. The need for balance and gradualism

Q: Why is it critical for the Commission to examine carefully the impacts of the NEM 3.0 successor tariff on customers who would adopt solar and solar-plus-storage systems?

A: The Commission cannot satisfy the sustainable growth requirement of Section 2827.1(b)(1) ["Ensure that customer-sited renewable distributed generation continues to grow sustainably"] without an in-depth examination of how NEM 3.0 proposals would impact the distributed solar market in California. To avoid a major disruption in that market, changes to the successor tariff should be implemented gradually, and must be calibrated to maintain solar and to promote the growth of solar-plus-storage, as reasonable options for customers. Customers need to understand the basic economic parameters that will impact their investments, and to have a sense that those key factors will remain stable enough over time to support their investments.

Q: Do Vote Solar and SEIA continue to agree, in concept, to the basic design of the successor tariff that the Commission's consultant, Energy & Environmental Economics (E3), proposed in its January 2021 white paper?

A: Yes. E3's basic design elements for the successor tariff include:

- **Gradualism.** Re-aligning the compensation for residential solar and solar-plus-storage customers should take place gradually, to avoid a severe disruption of the market for customer-sited renewable generation industry in California I agree with E3's statement that the "[p]reservation of a viable market is likely to require a "glide path…"
- **Preserve the economics of renewable DG.** The reforms to the successor tariff must be calibrated to ensure that BTM renewable generation remains a viable economic proposition for customers to install. I agree with E3's Glide Path 1 scenario that the

stepdown in the compensation to DG customers should be calculated to provide a 7.5-year simple payback to solar customers without the need for an upfront incentive.[44] This payback is reasonable to allow continued growth of these resources. Given the additional resiliency benefits of solar-plus-storage, the simple payback target for these systems can be 10 years.

- **Adjusting both rates and export compensation.** Changes to the economics of customer-sited renewable DG can be managed through changes to both the rates under which NEM 3.0 customers take service from the grid as well as the compensation they receive for the power that they produce.
- **Use of net billing.** I agree with E3's characterization of net billing as a "middle ground" approach to a successor tariff that would avoid the disruption of moving to an entirely new paradigm such as a "buy-all / sell-all" structure.[45]
- **Support beneficial electrification.** The E3 white paper, the SEIA / Vote Solar proposal, and the Commission's adopted principles all agree that the successor tariff should support the state's broader policy goal of encouraging beneficial electrification through the adoption of other types of DERs such as EVs and electric heat pumps. E3 suggests various rate designs that could be used for other types of DERs,[46] whereas our proposal takes that step immediately, by proposing that the foundation of NEM 3.0 should be the immediate use of the electrification rates that the Commission has already adopted for the IOUs. This would be an important step toward the development of a common rate platform for all types of DERs.

2. The problems with the proposals for drastic change

Q: How would you characterize the proposals that have been made in this case.

---

[44] See E3 White Paper, at pp. 29-31.

[45] *Ibid*., at pp. 16-17.

[46] *Ibid*., at p. 14: "any new rates implemented in this case could eventually serve as the basis for compensating all distributed energy resources (DERs), including unlocking the full value of battery storage as well as end-use and building electrification."

A: Regrettably, the proposals are polarized into two camps: one group of parties (CARE, CUE, the Joint IOUs, PAO, TURN, and NRDC) favors drastic changes that would result in immediate, major reductions in compensation for new residential solar customers. These parties favor much lower export rates based on the 2021 ACC as well as new grid access charges (GACs) that would assess utility system costs on power that never uses the utility grid because it is produced and self-consumed by the solar customer, behind the meter (BTM). As discussed in my opening testimony, these GACs would violate cost causation and the Commission's rate design principles.[47]

Other parties – including SEIA / Vote Solar, the California Solar & Storage Association (CalSSA), Sierra Club, Small Business Utility Advocates (SBUA), Environmental Working Group (EWG), and the Protect our Communities Foundation (PCF) – support gradual reductions in export rates and changes in rate design that align with the Commission's electrification efforts. This polarization is evident in the proposed paybacks for residential solar and solar-plus-storage customers, as shown in Figures 12 and 13 of our opening testimony. Those figures are based on the E3 analysis of simple paybacks in 2023, with the important change to use a solar cost forecast that is anchored in current solar costs in California. E3 uses an NREL ATB forecast of residential solar costs that begins in 2021 at a level that is clearly below today's recorded costs.[48] The orange lines in our Figures 12 and 13 also show the 2023 paybacks without the federal ITC for residential solar. The 2023 paybacks that E3 reports need to be considered without the ITC due to its expiration at the end of 2023. The orange lines in Figures 12 and 13 show that these paybacks will rise significantly in 2024 without the ITC.

---

47 See SEIA / Vote Solar opening testimony, at pp. 68-70.
48 See SEIA / Vote Solar testimony, at pp. 15-16 and Figure 1.

Q: Have you done further evaluation of the payback calculations, based on the Commission's adoption of the 2021 ACC as well as E3's revised analysis provided on June 16, 2021?

A: Yes, I have. Focusing first on the Joint IOUs' proposal, there are a number of additional changes that should be made to the E3 analysis of the paybacks under the Joint IOU proposal:

- The Joint IOUs' March 15 proposal includes export rates and GACs that are based on the 2020 ACC. As noted above, their June 18 testimony includes significantly higher GACs and lower export rates using the 2021 ACC. As avoided costs drop, the Joint IOU GACs will increase. However, the E3 analysis for 2030 uses the same Joint IOU GACs that are used for 2023 (except for the 4% per year rate escalation assumption), even though the 2021 ACC produces lower avoided costs in 2030 than in 2023. The lower avoided costs in 2030 will produce even higher GACs in 2030 than what E3 has modeled using the 2023 GACs.
- We calculate first-year bill savings assuming that the customer's rate schedule is the same both before and after installing solar.
- We are using a lower escalation rate – 3.5% per year – than the 4% per year rate that E3 is using. This produces somewhat lower paybacks in 2030.

Table 5 starts with the paybacks that E3 shows in its revised June 16 analysis of the Joint IOU proposal. Then we make the following adjustments to the E3 analysis:

1. Use the 2023 GACs from the IOU's testimony (which use avoided costs from the 2021 ACC);
2. Calculate new GACs for 2030 using 2030 avoided costs from the 2021 ACC.
3. Assume the same rate schedule both before and after the customer adds solar.
4. Use the SEIA-Vote Solar rate escalation of 3.5% per year from 2021-2030.
5. Use the higher solar and solar-plus-storage costs that SEIA and Vote Solar have recommended.
6. Show the paybacks without the ITC, due to its expiration at the end of 2023.

Table 5 shows that even simple paybacks under the Joint IOU proposals will exceed the economic life of solar and solar-plus-storage systems.

Table 5 – *Revising the E3 Analysis of the Joint IOU Paybacks*

IOU	Adoption Year	IOU Proposal	IOU Testimony	Escalated GBCs	Same Rate	3.5% Escalation	SEIA-VS Costs	No ITC In 2023
	Solar Only							
PG&E	2023	21	24	23	27	27	30+	30+
	2030	16	19	23	30+	30+	30+	30+
SCE	2023	17	20	25	22	22	29	30+
	2030	12	14	17	15	15	21	21
SDG&E	2023	9	10	13	28	28	30+	30+
	2030	6	6	9	24	24	30+	30+
	Solar + Storage							
PG&E	2023	17	18	17	19	19	26	30+
	2030	13	14	16	17	18	28	28
SCE	2023	12	12	14	13	13	18	23
	2030	9	9	10	10	10	16	16
SDG&E	2023	8	9	10	15	15	22	27
	2030	6	7	8	12	12	19	19

Table 6 goes through the same steps of revising the E3 payback analysis for the revised SEIA-Vote Solar proposal, again starting with the paybacks that E3 shows for the SEIA – Vote Solar proposal in its June 16 analysis.

Table 6 – *Revising the E3 Analysis of the SEIA / Vote Solar Paybacks*

IOU	Adoption Year	Initial Proposal	Revised Proposal	Same Rate	3.5% Rate Escalation	SEIA-VS Costs	No ITC In 2023
	Solar Only						
PG&E	2023	5	5	5	5	7	9
	2030	4	6	5	6	8	8
SCE	2023	6	6	6	6	8	10
	2030	4	5	5	5	7	7
SDG&E	2023	4	4	4	4	6	7
	2030	3	3	4	5	6	6
	Solar + Storage						
PG&E	2023	6	6	6	6	8	10
	2030	5	6	6	6	9	9
SCE	2023	7	7	7	7	9	12
	2030	5	5	5	5	9	9
SDG&E	2023	4	4	5	5	7	10
	2030	3	4	5	5	8	8

Q: Please comment on the simple paybacks proposed by the parties who favor sudden and drastic reductions in NEM compensation.

A: The paybacks under these parties' proposals show that distributed solar and solar-plus-storage for residential customers would no longer be economic under the general market tariff. This would be particularly true for low-to-moderate income customers that cannot make a cash purchase and must finance their solar investment. The simple payback metric assumes a cash purchase and does not consider the time value of money. As discussed in my opening testimony, financing costs add as much as 40% to the simple payback period. As a result, simple paybacks that are more than 10 years are unlikely to attract significant customer interest.[49] CARE, the Joint IOUs, and TURN propose an immediate increase in 2023 in the simple payback for residential solar from 5 years to more than 20 years; PAO's simple payback is only slightly lower, at 17 years. As a result, these parties propose to increase paybacks by three to four times in one step, compared to the paybacks under NEM 2.0. NRDC's payback is lower only because it has proposed that the Commission approve whatever level of upfront incentive is needed to reduce the simple payback to 10 years. For context, the Nevada commission's precipitous end to NEM in that state in 2015, which shut down the rooftop solar market in Nevada, resulted in a doubling of paybacks in that state.[50] The impact of these drastic changes would be to destroy the economics of rooftop solar in California, and to erect a substantial roadblock to the transition to more valuable solar-plus-storage systems.

---

[49] An investment that has equal annual returns and a 10-year simple payback will have an internal rate of return (IRR) of about 8.8%, which is close to the customer discount rate of 8% recommended in the NEM 2.0 Lookback Study. A similar investment with simple paybacks of 15 or 20 years will have IRRs of just 4.4% and 1.8%, respectively.

[50] See *Prepared Direct Testimony of R. Thomas Beach on behalf of The Alliance for Solar Choice*, filed February 1, 2016 in PUCN Dockets Nos. 15-07041 and 15-07042, at Table 1 and 2. The paybacks discussed in this testimony are not simple paybacks, but longer discounted payback periods that consider the time value of money, rate escalation, and output degradation. In terms of simple paybacks, the PUCN's December 2015 order that shut down the rooftop solar market in Nevada increased simple paybacks from 11 to 17 years in the southern Nevada market.

Q: Can you provide calculations of the change in the bill savings available to a new solar customer, in moving from NEM 2.0 to NEM 3.0, if the Joint IOU, PAO, or TURN proposals were to be adopted?

A: Yes. The following **Table 7** shows those changes. These calculations are for a residential customer on an electrification rate, and use the Grid Access Charges included in these parties' testimony, based on the 2021 ACC.

Table 7 – *Change in Bill Savings - NEM 2.0 to NEM 3.0 - Joint IOU, PAO, and TURN ($/kWh)*

	Joint IOU			Public Advocates Office			TURN		
	PG&E	***SCE***	***SDG&E***	***PG&E***	***SCE***	***SDG&E***	***PG&E***	***SCE***	***SDG&E***
	Solar Only								
NEM 2.0	0.231	0.184	0.261	0.231	0.184	0.261	0.231	0.184	0.261
NEM 3.0	0.058	0.064	0.060	0.114	0.090	0.118	0.071	0.061	0.081
% Change	**-75%**	**-65%**	**-77%**	**-50%**	**-51%**	**-55%**	**-69%**	**-67%**	**-69%**
	Solar + Storage								
NEM 2.0	0.298	0.244	0.298	0.298	0.244	0.298	0.298	0.244	0.298
NEM 3.0	0.103	0.138	0.127	0.206	0.182	0.217	0.130	0.121	0.152
% Change	**-65%**	**-44%**	**-57%**	**-31%**	**-25%**	**-27%**	**-56%**	**-50%**	**-49%**

The available bill savings for solar-only customers would drop immediately by 50% to 77%, while the bill savings for solar-plus-storage customers would fall by 25% to 65%. Again, bill savings reductions of about 40% precipitated the Nevada crisis in 2015-2016.[51]

Q: If the Commission were to adopt the drastic reductions in bill savings shown in Table 7, would that change California's status as a national leader in solar adoption?

A: Yes. The proposals of the Joint IOUs, PAO, and TURN would turn California into a state with low solar adoption rates going forward, reversing its current position as a national leader. This can be seen in the following analysis of EIA data on distributed solar adoption in all 50 states. The adoption of distributed solar is a function of the value available to an electric customer from producing electricity with an on-site PV system.

---

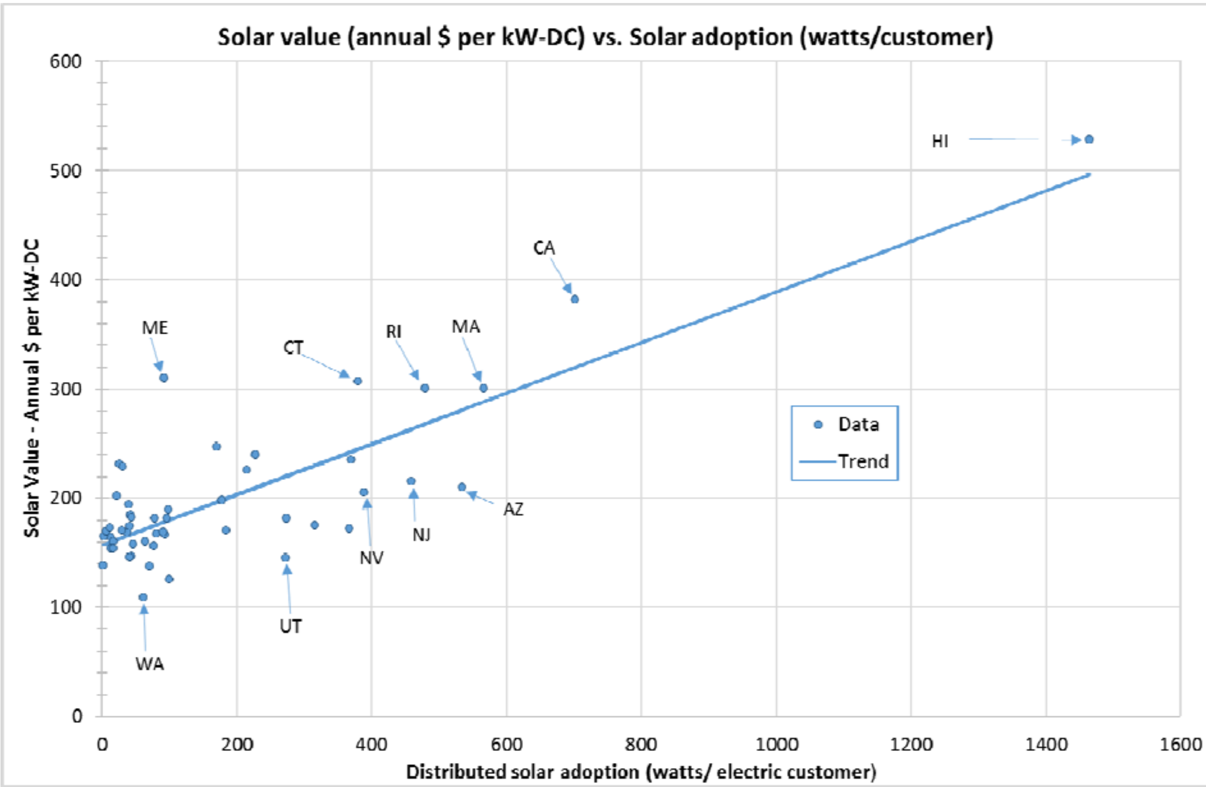
[51] *Ibid*, at pp. 14-16.

This depends on the available solar insolation and the prevailing electric rate. I have calculated the annual "solar value" for each U.S. state as its average residential electric rate (from April 2021 EIA data) times the annual output of a typical solar system (in annual kWh per kW) in each state's largest city (from the NREL PVWATTS calculator).[52] The following **Figure 5** plots each state's solar value versus cumulative adoption of distributed solar in that state, as of April 2021. The metric for cumulative solar adoption in each state is the per capita installed distributed solar capacity, in watts per electric customer (again using April 2021 EIA data). The figure shows clearly that solar adoption increases as solar value increases.

Clearly, if a state takes action to reduce the solar value available to electric customers – for example, by changing NEM rules to limit compensation to NEM customers to just a fraction of the retail rate – adoption will be lower. For example, the Joint IOU proposal to reduce residential bill savings to about $0.07 per kWh would lower California's annual solar value by 70%, from $388 to $116 per kW-year. This would reduce rooftop solar adoption going forward to the much lower levels of the states on the left side of this figure.

[52] The solar value metric implicitly assumes that most states have made available some form of NEM, such that customers receive value roughly equal to the state's average retail electric rate if they produce on-site solar electricity. This is a reasonable assumption, given that 44 states have adopted and used some form of NEM over the last 15 years when distributed solar has become a mainstream energy resource.

Figure 5



Q: Can you provide examples of states with low solar values of $150 per kW-year, or less, and state what the level of solar adoption is in those states?

A: Yes. One such state is Idaho, with typical bill savings of 9 cents per kWh [for Idaho Power], a solar value of $140 per year, and solar adoption of 70 watts per electric customer. Idaho has a reasonably good solar resource, but retail electric rates are low due to the availability of significant hydro generation. Another similar state would be Arkansas, with typical bill savings of 10 cents per kWh [for Entergy Arkansas], a solar value of $150 per year, and solar adoption of 44 watts per customer. Arkansas recently reaffirmed the availability of full retail net metering for residential customers, but Arkansas' low retail rates have limited adoption. Nationally, states with solar values of $200 per kW-year or less have adoption rates for distributed solar that average 87 watts per electric customer, which is just 12% of the 700 watts per customer that California has achieved.

3. Providing adequate investment certainty for DER customers

Q: Please discuss the best approach to compensating solar customers, in terms of customer acceptance and understanding.

A: One of the strengths of NEM is its direct link to the retail rate, which is the rate that customers understand and that they have experienced over time. Most of the NEM reforms in other states have maintained the link to retail rates, by allowing customers to offset their on-site usage at the retail rate, by indexing the export rate to a percentage of the retail rate, or both.[53] To promote customer understanding and acceptance, the SEIA / Vote Solar proposal would maintain that linkage – both allowing customers to offset their on-site usage using a standard electrification rate and setting export rates at a defined percentage of the retail rate.

Q: You have discussed above the problems with the proposals that would make direct use of volatile and uncertain ACC values. Do any of the parties that would use the ACC directly recognize the problems that ACC values may change over time and that customers need greater assurance of what their export compensation will be?

A: Yes. TURN gives some recognition to the fact that customers will not understand how the ACC may change over time, and proposes to offer 5- or 10-year fixed export rates based on the current ACC. NRDC also recognizes this problem, to a lesser extent, with its proposal to use 3-year forward ACC values and then to fix them for 10 years.[54] But TURN undermines much of the certainty in its 10-year fixed price offer, by proposing to link the energy portion of export rates to actual CAISO energy market prices. Residential customers have no direct experience or information on CAISO market prices, and cannot be expected to become, in essence, merchant solar plants on dynamic rates. SEIA

---

[53] The other alternative that has been used is the approach used in Arizona, where the Arizona Corporation Commission has established an export rate linked to utility-scale solar costs plus avoided T&D that is fixed for a 10-year period and that cannot decline by more than 10% per year for each annual tranche of solar customers.

supports the dynamic rate pilot programs that are under discussion in several GRC Phase 2 cases, but solar customers should not be forced to participate in such a pilot.

The major issue with these proposals is that the change from the 2020 ACC to the 2021 ACC had a major impact even on 10-year levelized export values, as shown in Table 8.

Table 8: *Levelized 2023-2032 (10-year) ACC Values ($/kWh)*[55]

Model	PG&E CZ12	SCE CZ10	SDG&E CZ10
2020 ACC (v1c)	0.0983	0.1169	0.1000
2021 ACC (v1a)	0.0376	0.0536	0.0364
% Change	-62%	-54%	-64%

The availability of a 10-year levelized export rate would provide a prospective customer with greater certainty in their export compensation, but the California rooftop solar market will still face major uncertainty from year to year if the 10-year fixed export rates can fluctuate by more than 50% in just one year due to ACC changes.

Q: The Joint IOUs, PAO, TURN, and NRDC all propose some form of Grid Access Charge (GAC) designed to recover utility system costs for customer generation that is used behind the meter, that is not metered, and that never touches the utility grid. Your opening testimony, at pages 66-73, discusses at length why the proposed GACs are contrary to cost causation principles and would be unduly discriminatory if applied only to solar customers. Are there aspects of the GAC proposals that will result in compensation that varies over time, that will be challenging to forecast, and that will be difficult for customers to understand?

A: Yes. One of the Commission's rate design principles is that "rates should be stable and understandable and provide customer choice."[56] The proposed GACs would be neither

[54] See NRDC testimony, at pp. 14-16. Of course, NRDC fails to recognize that its proposal will underpay solar customers if avoided costs are increasing.

[55] These calculations use the solar profiles from the E3 Residential Bill Model.

[56] See D. 15-07-001, at page 28.

stable nor understandable for the typical residential customer. And because the GACs are fixed monthly charges, the customer has no choice but to pay them (or to not adopt solar). As discussed below, the proposals to implement a GAC would sever any link between NEM compensation and the only rate that a prospective residential solar customer knows well, which is the overall retail rate that they pay.

For example, the Joint IOUs' GAC would be based on the solar customer's bill savings at the retail rate, less the avoided costs from the ACC. This would enable the utility to collect, for the customer's solar output that is consumed BTM, all of the costs that the utility would have collected in the absence of the solar unit, except for the ACC-based avoided costs. When combined with the export rate set directly using the ACC, the Joint IOUs' proposal essentially amounts to compensating a solar customer at the current ACC rate for all of its output.[57] The Joint IOUs' GAC thus would vary based on unpredictable changes to the ACC. This can be seen in Table 2, which shows the increase in the Joint IOUs' GACs due to the change from the 2020 ACC to the 2021 ACC.

The PAO's proposed GAC has many different problems.

First, PAO's GAC is based on an estimate from the NEM 2.0 Lookback report of how much solar customers contribute to their cost of service. This is a backward-looking cost-of-service study, based on a period with negligible numbers of solar-plus-storage customers who may have a significantly different cost-of-service profile than solar-only customers. Solar-plus-storage customers are likely to cover a higher percentage of their cost of service, as they can shift solar output to the high-cost on-peak hours, so the customer loads that the utility serves will be in lower-cost hours. The cost-of-service study in the NEM 2.0 Lookback report will be increasingly outdated over time, as the

[57] As an example, the E3 model estimates that the Joint IOU proposal would produce first-year bill savings in 2023 for a PG&E residential customer of 5.8 cents per kWh. This is similar to the 2023

percentage of solar-plus-storage customers grows. It is also unclear when and how the cost of service study on which PAO relies will be updated. If such cost-of-service studies are always backward-looking, they will never reflect accurately the future portfolio of solar and solar-plus-storage customers to which the rates will apply.

Second, PAO uses a cost-of-service metric from the NEM 2.0 Lookback study that is based on the net loads of NEM 2.0 customers, which is the difference between their imports and exports. This metric shows that NEM 2.0 customers cover just 9% to 18% of their cost of service.[58] PAO then assumes that 44% to 64% of this shortfall is due to exports to the grid, based on the average percentages of NEM generation exported. PAO then uses the remaining shortfall – for solar generation consumed behind the meter – as the basis for PAO's GACs.[59] This shortfall ranges from 32% (SDG&E) to 41% (PG&E) to 51% (SCE) of the residential cost of service.[60] The fundamental problem with this approach is that there is no utility "cost of service" for exports to the grid – this is a service that the NEM customer is providing to the utility, not the other way around. After the exported power passes the NEM customer's meter, it becomes the utility's power, and the utility provides a service to a neighboring customer by delivering those kWh to the neighbor. The utility's cost of service is only relevant to the service that the NEM customer receives when it imports power from the utility system. PG&E presented testimony in its current GRC Phase 2 on an initial analysis of residential NEM customers' generation and distribution cost-of-service using actual metered data on the power that both NEM and non-NEM customers import from the grid. This would be a more direct and accurate measure of NEM customers' cost of service than PAO's rough assumption based on the relative amounts of solar power used behind the meter or exported. PG&E's initial analysis is that the generation and distribution cost of service for residential NEM

---

avoided cost value of a solar profile for a PG&E residential customer in CZ4, using the 2021 ACC, of 5.3 cents per kWh.

[58] See PAO testimony, at pp. 3-31 to 3-32 and Table 3-9.

[59] *Ibid*., at pp. 3-40-to 3-42 and Tables 3-10 and 3-11.

[60] *Ibid*., at Tables 3-11, Column D.

customers is 17% higher than the average cost of service for the residential class as a whole.[61] Since NEM customers pay the same rate for delivered power as regular customers, PG&E's cost of service analysis suggests that the shortfall in what residential NEM customers pay is less than the 32% to 51% shortfall that PAO calculates. Neither PAO nor SEIA have endorsed PG&E's generation and distribution cost-of-service analysis in its GRC, but directionally it indicates that PAO's proposed GAC is significantly overstated. Further, a large and diverse class of customers such as residential will have customers who cover a broad range of percentages of the class-average cost of service. This range needs to be better delineated before conclusions are drawn about the reasonableness of NEM customers' contribution to the cost of service. PG&E's analysis also will need to be extended to transmission and other cost components and subject to further scrutiny in future rate cases.

Third, there is an issue about the exact marginal costs that should be used for a utility's cost of service, because for many years most General Rate Case (GRC) Phase 2 proceedings have resulted in settlements in which marginal costs are not explicitly adopted, but are left as "black boxes."[62] The record in GRC Phase 2 cases shows that there is often a significant range of marginal costs presented by the parties. It is problematic if the Commission then defaults to the utility-proposed marginal costs for use in the ACC, as the Commission did in D. 20-04-010. This allows the IOU to use unapproved marginal cost values in the ACC, marginal costs that may be different than the values used in GRC Phase 2 settlements and in the IOUs' actual rates. The same issue also applies to how marginal costs are allocated to the hours of the day. Further, the marginal costs used in the Lookback study date from 2016-2018 – and thus are 3 to 5 years old – and are not from the most recent IOU GRC Phase 2 cases. These issues with

---

[61] See A. 19-11-019, Exhibit PG&E-2, Cost of Service (July 2020 Errata, July 16, 2020), at Tables 3-10A and 8-5, comparing the NEM residential cost of service to the overall residential cost of service for both NEM and non-NEM customers.

using cost-of-service metrics to evaluate NEM are not new – they also were identified by E3 in the cost-of-service section of its 2013 NEM evaluation.[63] Under the PAO proposal, the investments of NEM 3.0 solar customers would be at the mercy of future cost-of-service studies that would be used to re-set their GACs in difficult-to-predict ways.

The TURN proposal would charge solar customers certain "non-bypassable" and "unavoidable / shared" (NUS) costs for their output that is used behind the meter, even though this power does not touch the grid, is not metered by the utility, and does not cause such costs to be incurred. Prospective solar and solar-plus-storage customers have no experience or knowledge of what the NUS rate components are or how they may change over time. It is also complicated for customers to estimate what their own BTM usage will be, requiring customers to download their hourly usage and compare it to their expected hourly solar output profile. Finally, TURN would include all transmission and distribution costs as "unavoidable / shared" costs without recognizing that there are marginal T&D costs that solar customers can avoid and that are included in the ACC.[64]

Q: Do you have an example of a Commission solar program that has not been successful because the compensation for generators is based on difficult-to-forecast rate components that change every year?

A: Yes. California's community solar program for third-party developers – the Enhanced Community Renewables (ECR) program – has been in place since 2015, but to my knowledge no ECR projects have been developed successfully over the last six years.[65]

---

[62] This may be changing with the current litigation of PG&E's marginal costs in A. 19-11-019. But, on the other hand, the recent SDG&E GRC Phase 2 settlement in A. 19-03-002 did not adopt specific marginal costs.

[63] See E3, *California Net Energy Metering Ratepayer Impacts Evaluation* (October 2013), at pp. 88-89.

[64] See TURN testimony, at pp. 48-51.

[65] The ECR program is part of the Green Tariff Shared Renewables (GTSR) program authorized by SB 43, with a maximum capacity of 600 MW split among the three IOUs. No ECR capacity has been successfully brought on-line. According to the Q1 2021 GTSR progress reports of the three IOUs, the IOUs have subscribed about 75 MW of the 600 MW through their Green Tariff programs, although this amount has fluctuated significantly. For example, SDG&E's GTSR reports show that utility was close to

The compensation for the customers of ECR projects is based on a complicated mixture of generation rate components, the Power Charge Indifference Adjustment (PCIA), a "solar value adjustment," and a Resource Adequacy component. These components change at least every year, in ways that are difficult to forecast.[66] Even though ECR projects are for sophisticated developers of utility-scale solar projects, no developer has been able to finance and to attract customers for an ECR project, because the compensation to ECR customers is so changeable and difficult to forecast with any assurance. Given the volatility we have seen with the ACC, as well as the complex mixtures of rate components in the PAO and TURN proposals, the same problem with a lack of rate certainty will exist were the Commission to approve the GACs that the Joint IOUs, PAO, and TURN have proposed.

Q: Are there common features between the PCIA used for the failed ECR program and the GACs proposed in this case?

A: Yes. For generation costs, the PCIA is essentially the difference between (1) the generation component of rates and (2) a short-term forecast of CAISO market prices using forward market prices plus a resource adequacy (RA) component that measures short-term generation capacity costs and an adder for RPS costs. Thus, the PCIA assumes that departing load avoids only short-term CAISO market prices plus the RA and RPS components. Similarly, the near-term avoided energy costs in the ACC also are

---

full enrollment of its GT program at the end of 2020 (51.1 MW enrolled), but that enrollment dropped by over 50% to 24.6 MW by the end of March 2021. See https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M382/K617/382617854.PDF. In 2019, SCE proposed terminating the GTSR program, due to the program's "financial viability" being "unsustainable." The Commission denied this request in Resolution E-5028; see page 10 of the resolution for SCE's request.

[66] The Commission has required the IOUs to attempt to forecast ECR credits over the next 20 years. However, the Commission also required the IOUs to include a sobering disclaimer with such forecasts, such as the following from SCE: *"As the CPUC acknowledged in D.16-05-006, an estimate of GTSR credits and charges for 20 years (or even 5 to 10 years) is challenging and unlikely to be accurate. Moreover, the 20-year forecasts shown here are not necessarily representative of SCE-specific forecasts of rate components. SCE can neither predict nor guarantee any actual cost savings or increases due to changes to these credits and charges, and such changes will affect actual costs."*

based on forward market prices for the CAISO market. The generation capacity component of the ACC is calculated from the cost of new entry (standalone storage costs), but is similar in magnitude to the RA and RPS components of the PCIA.[67]

Q: Would this lack of certainty as to the future rates that residential solar customers would face have implications for the ability of customers to obtain financing for their systems?

A: Yes. Solar loans and power purchase agreements have been key means to extend access to solar to low- and moderate-income households who do not have the capital to make a cash purchase. Lawrence Berkeley National Lab's (LBNL) annual *Tracking the Sun* reports show that 37% of systems installed in 2019 were third-party-owned; this percentage approached 60% in 2012, but has dropped as solar loans have replaced PPAs.[68] Two-thirds of host-owned systems are financed.[69] This means that, overall, almost 80% of residential solar systems are financed. These financing structures depend on the ability of lenders to know that solar customers will save enough on their utility bills to cover the loan or PPA payments. Financing for solar may be more difficult and expensive to obtain, if solar savings become uncertain due to a NEM 3.0 structure that includes (1) new charges (such as the proposed GACs) that change each year and are difficult to predict and (2) export rates that fluctuate with an ACC model that is updated every year.

Q: Both TURN and NRDC have proposed the use of GACs, but both also have supported the idea of a Market Transition Credit (MTC) as an upfront incentive

---

[67] The avoided generating capacity costs in the 2021 ACC are about $15 per MWh for a baseload profile. The RA and RPS components of the market price benchmark used in the PCIA for 2021 are about $20 per MWh (from Energy Division's "Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up" [November 2, 2020]).

[68] See LBNL, *Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States* (October 2019), at pp. 16-16 and Figure 11. The 2019 third-party-owned figure is from LBNL's 2020 *Tracking the Sun* data update, at Slide 15.

[69] *Ibid*., at p. 19, footnote 8, citing Wood Mackenzie data from 2018.

designed to produce a certain simple payback for NEM 3.0 systems. NRDC has suggested that the MTC should be structured to provide a 10-year payback;[70] TURN supports an MTC designed to give a 10-year payback for CARE customers and a 15-year payback for non-CARE. However, only the CARE MTC would be funded by other ratepayers (including NEM 1.0 and 2.0 customers).[71] Please comment on the use of an MTC to realize a specific payback period.

A: The issue with this concept is that both TURN and NRDC are supporting such high monthly GACs and such low export rates that a solar customer will have only small bill savings. As a result, a substantial MTC will be required to realize a reasonable payback. For example, this table of paybacks from TURN's testimony shows that, without an MTC, TURN's successor tariff would not be even close to economic for either CARE or non-CARE customers.[72]

TURN SUCCESSOR TARIFF PROPOSAL (NO MTC) PAYBACK PERIODS, IRRs AND FIRST YEAR COST SHIFTS						
	PG&E		SCE		SDG&E	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Simple Payback (years)	20	20	36	33	38	35
E3 Payback (years)	22	21	39	36	41	41
Escalated Simple Payback (years)	18	17	Over 20	20	Over 20	19
Simple Discounted Payback (years)	Over 20	Over 20	Over 20	Over 20	Over 20	Over 20
Full Discounted Payback (years)	Over 20	Over 20	Over 20	Over 20	Over 20	Over 20
First Year Cost Shift ($)	$80	$280	$(132)	$(93)	$(54)	$(9)
IRR (%)	1%	2%	-3%	-2%	-3%	-2%

[70] NRDC testimony, at pp. 14, 16, and 19: "A critical part of the NRDC Successor Tariff proposal is to ensure that distributed generation systems have at most a ten-year payback period."

[71] TURN testimony, at p. 51-55.

[72] *Ibid*., at p. 69.

To remedy this, TURN proposes very large MTCs in order to provide CARE customers with a 10-year payback. Non-CARE customers would be limited to a 15-year payback and required to seek MTC funding from non-rate sources. TURN's MTCs for CARE customers are as high as $2.33 per watt ($2,331 per kW for SDG&E – see the chart below[73]).

TURN Proposal – MTC values for CARE customers 10 year discounted payback target			
Payback Metric	**PG&E**	**SCE**	**SDG&E**
Avg ($/kW-ac)	$1,737	$2,231	$2,331
Min ($/kW-ac)	$1,606	$1,864	$1,884
Max ($/kW-ac)	$1,866	$2,715	$2,966

$2.33 per watt-DC is about 80% of the after-ITC costs of a solar system based on our estimate of residential solar costs in California in 2023.[74] So, in essence, TURN's proposal is that CARE customers would have most of their solar system paid for by other ratepayers, but the customer who receives such a system would save only small amounts on their energy bills. This model raise issues such as: (1) how would access to these large incentives be allocated?; (2) the solar customer receives little hedge value in terms of protection from future rate increases; (3) the customer has only a small amount of skin in the game, and so has little incentive to maintain the system; and (4) the CARE solar customer has to go onto a very complex rate, perhaps adding a production meter as well to measure their on-site usage, which will make it difficult for the customer to understand when to use and when to conserve energy.

The TURN/NRDC proposals to provide new solar customers with low bill savings, but high upfront incentives, will raise a host of new issues and disruptive problems. TURN itself admits that subsidies of $600 million per year would be needed

[73] *Ibid.*, at p. 73.
[74] Our forecasted residential solar costs in 2023 are $3.20 per watt. See Figure 1 of our testimony.

to keep the non-CARE solar market at present levels;[75] if solar also is provided to 40,000 CARE customers per year using TURN's subsidies of about $10,000 each, that will require another $400 million per year. Even if the money for $1 billion in annual subsidies was made available, there would be a host of new issues surrounding how to allocate access to these large subsidies in a fair and equitable manner. Who would be the gatekeeper? How would access be structured such that the subsidies do not just flow to the well-educated or well-connected who have good Internet access and skills?[76] The Commission should weigh carefully the unintended consequences, problems, and disruptions of moving to a completely new – and not necessarily more equitable -- scheme for allocating access to a highly desired DER technology.

4. Issues concerning solar-plus-storage customers

Q: Solar-plus-storage customers also would have to pay the GACs that the Joint IOUs, PAO, TURN, and NRDC have proposed. Would this be fair to these customers, who are adopting systems that offer far more value to the grid?

A: No, it would not. A major issue with the GAC proposals is that they are premised on customers continuing to adopt solar-only systems. However, customer demand – and the solar industry's focus – is shifting to solar-plus-storage systems. I noted above that the PAO's GAC uses the cost-of-service analysis from the NEM 2.0 Lookback Study that is based on the cost of service only for solar customers and that is not based on the service (imported power) that solar customers receive from the utility.[77] It is my expectation that solar-plus-storage customers will cover a higher portion of their cost of service. Similarly, the Joint IOUs calculate their GACs based on the on-site consumption of solar

[75] TURN testimony, at p. 54.

[76] This is a problem that we all have recently experienced with access to vaccinations for Covid-19.

[77] See NEM 2.0 Lookback Study, at p. 47: "Our approach uses the information described above to estimate the cost of service for the pre- and post-NEM 2.0 load shape. The estimates of cost of service are then compared to estimates of customers' pre- and post-NEM utility bills to analyze the utility, technology, and sector specific aggregate bill relative to the estimate of their average cost of service."

customers, but would apply them to both solar and solar-plus-storage customers.[78] The IOUs assert that they will review the appropriateness of continuing to use the same GACs for both types of customers, and may propose higher GACs for solar-plus-storage customers in future ratemaking cases if it turns out that solar-plus-storage customers are able to use a higher percentage of their output to serve on-site loads.[79] The Joint IOUs do not discuss whether the GACs for solar-plus-storage customers could be reduced by the higher avoided costs of more valuable solar-plus-storage systems. This uncertainty, and the possibility that the IOUs may propose higher GACs for solar-plus-storage customers, will discourage adoption of these high-value systems.

Q: What is the impact on solar-plus-storage customers of the Joint IOU proposal to move to monthly true-ups in which monthly net exports in any TOU period are paid low Net Surplus Compensation (NSC) rates?

A: The impact would be to discourage these customers from cycling their storage in a way that benefits the system – filling storage with solar output during the midday off-peak hours, then fully discharging it during the evening on-peak hours. The export credits that solar-plus-storage customers earn should be much higher than the export credits for solar-only customers, because the storage allows the solar to be stored and then exported during more valuable on-peak hours. However, the IOU proposal would price any net exports in a time-of-use period at low NSC rates, even if those exports happen during the valuable on-peak hours. NSC rates are based on simple monthly averages of daytime CAISO wholesale market prices and would provide no incentive to export energy when it is most valuable to the system. This problem is shown in **Table 9** below. The left side of the table shows that, under the IOUs' proposed monthly true-up, a solar-plus-storage customer would see their average export credit <u>drop</u> by 6% to 13%, for PG&E and SCE, respectively, compared to the export credits for a solar-only customer.[80] Export credits

---

[78] See Joint IOU testimony, at p. 138.

[79] *Ibid.*, at pp. 138-139.

[80] These calculations use E3's residential bill savings model. The assumed customer has usage of 7,500 kWh per year and a solar system producing 100% of this usage.

would increase by just 2% for SDG&E. The right side of the table shows that with the current approach of annual true-ups – in which all monthly exports would be priced at avoided cost under the IOU proposal – a solar plus storage customer would see 18% to 24% increases in their average export rate. Thus, the IOUs' proposed monthly true-ups would erect yet another barrier to the use of solar-plus-storage systems.

Table 9: *Average Export Credits –Monthly vs. Annual True-ups ($/kWh)*

	Joint IOU Proposal Monthly True-up			**All Exports at Avoided Cost Annual True-up**		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Solar Only	0.040	0.045	0.039	0.042	0.045	0.042
Solar + Storage	0.037	0.039	0.040	0.051	0.052	0.052
Percent Change	-6%	-13%	+2%	+23%	+18%	+24%

5. The C&I market is already subject to significant fixed charges

Q: The Joint IOUs would apply their GAC methodology to all rate classes, while PAO would only levy a small GAC on non-residential customers, to collect certain non-bypassable costs on BTM usage.[81] Please comment on this difference.

A: PAO recognizes correctly that "Non-residential tariffs collect less revenue via volumetric rates and more revenues via fixed and demand charges, so the cost burden generated per kW is much smaller than for residential."[82] This is certainly a sound reason not to impose new large fixed charges on commercial and industrial (C&I) customers who install solar. However, neither the Joint IOUs nor PAO confront the key question with respect to compliance with AB 327 – how to ensure sustainable growth in the C&I market. The growth in this market clearly is slowing, due to the change to a 4p to 9p peak period.[83] The market needs time to allow further development and cost reductions

81 See PAO testimony, at pp. 3-45 to 3-46. IOU testimony, at pp. 144-148.
82 PAO testimony, at p. 3-45.
83 See SEIA / Vote Solar proposal, at Figure 6.

in larger solar-plus-storage systems that are needed to serve C&I customers effectively. None of the advocates for new fixed charges for C&I solar customers have provided evidence that reasonable paybacks would still be available in this market if new fixed charges are imposed on solar customers. There is the added complexity that this market is very diverse, in terms of the sizes, load profiles, and sophistication of the customers, and deserves more attention than has been possible in this case, which has focused on the residential market where the cost shift issues are significantly larger in magnitude. Finally, the NEM 2.0 Lookback study shows that, after installing solar, non-residential customers continue to pay rates that fully cover their costs.[84] This reflects the fact that commercial loads generally peak earlier in the day and are a better match for solar output than residential loads.

Q: The C&I market also includes a significant segment of non-profit institutions, including schools. Has a recent decision recognized the burdens that additional fixed charges place on the ability of these customers to adopt DERs?

A: Yes. D. 21-07-010 in the current SDG&E GRC Phase 2 case rejected SDG&E's proposed schools rate, due to a concern that the higher fixed charges in that rate would impair the ability of smaller schools to take actions to reduce their energy costs:

> SDG&E contends that it has provided the schools with better tools to plan for budget and energy expenses since a fixed monthly fee and flat volumetric charge decrease bill volatility. With fixed rates, however, there is less incentive to change behavior if electric bills cannot be impacted. Consequently, we find that the fixed monthly service fees built into the default rates for small and medium to large schools do not support conservation and energy efficiency, and are inconsistent with RDP [Rate Design Principle] number 4.[85]

---

[84] *Ibid.*, at p. 98. Table 5-11 shows that non-residential NEM customers pay more than their cost of service (i.e. 152% for PG&E, 108% for SCE, and 166% for SDG&E).

[85] See D. 21-07-010, at p. 67.

B. Electrification Matters

1. Distributed generation will advance electrification

Q: The Joint IOUs, PAO, and TURN have suggested that the rate impacts of the existing NEM program present a major barrier to the state's electrification efforts.[86] Please respond.

A: My opening testimony explained at length that most, if not all, of the alleged NEM above-market cost shift would have resulted in any event.[87] If NEM systems had not been developed, they would have been replaced with utility-scale solar that would have incurred a similar level of above-market costs. This directly contradicts the utility argument that the NEM cost shift has raised rates, compared to a world in which these resources were not developed.

Q: How does the 2021 ACC impact your cost-shift analysis?

A: Of course, the lower forward-looking avoided costs will increase the calculated cost shift, compared to the use of the 2020 ACC. However, the cost shift in the residential market remains offset by the significant societal benefits of distributed solar. Moreover, the Commission's statement in Resolution E-5150 that the decline in avoided costs from the 2020 to the 2021 ACC is driven by lower costs for utility-scale solar and storage underscores that there will continue to be a certain level of above-market costs regardless of whether the state pursues utility-scale or distributed solar.

Q: The Commission held an *en banc* hearing on February 24, 2021 to consider the factors that have caused recent persistent increases in IOU electric rates. Please comment on the factors identified at the *en banc* as driving rate increases.

---

86 Joint IOU testimony, at pp. 1 and 15-16; also, PAO testimony, at pp. 2-14 to 2-15 and 2-23 to 2-27; and TURN testimony, at p. 40.

87 SEIA / Vote Solar testimony, at pp. 62-63 and Attachment RTB-4.

A: At the *en banc*, the Commission staff cited a number of factors, listed below, as major cost drivers of high rates.[88] Significantly, DERs can address many of these factors, as follows:

- **Transmission rates.** Distributed solar and storage can reduce both the gross and net load peaks that drive the need for capacity-related transmission. Generation from distributed renewables also substitutes for utility-scale renewables that may require new rate-base transmission to be fully deliverable to load.
- **IOU rates of return.** DERs can avoid capacity-related rate base additions for generation, transmission, and distribution.
- **Wildfire costs.** Distributed resources can avoid the need to expand the T&D system that has been the cause of some destructive wildfires.

Q: Are there other important barriers to beneficial electrification that should be recognized?

A: Yes. The current "TOU-lite" design for the PG&E and SDG&E default residential rates – a rate design supported by PAO and TURN – is a major barrier to electrification because it results in relatively high off-peak electric rates. For example, the winter off-peak non-baseline default rates for PG&E and SDG&E residential customers today are $0.30 per kWh for PG&E (Schedule E-TOU-C) and over $0.40 per kWh for SDG&E (off-peak and super-off-peak for Schedule TOU-DR1). As discussed in the next section, lower off-peak rates are important for EV charging and heat pumps that must compete with fossil fuels. This default rate design is also a significant contributor to the NEM cost shift, compared to rates designed for electrification that have lower off-peak rates and larger peak-to-off-peak rate differences.

2. The need to expand off-peak electric use

Q: Given the relatively high electric rates of the California IOUs, how can the Commission encourage beneficial electrification that is price-sensitive?

---

88 See the CPUC Energy Division staff presentation from the February 24, 2021 rates *en banc*, at Slides 2, 3, 6 to 9, and 17 to 21.

A: Economic electrification in California will require a dramatic expansion of off-peak electric use. There is a critical need for long-term, stable rate designs that feature low off-peak electric rates that can compete with liquid fossil fuels to charge EVs and to supply heat pumps that displace natural gas use in buildings. Average residential electric rates for PG&E and SDG&E already may be too high to provide EV charging customers with consistent savings compared to gasoline prices. Low-cost off-peak power is also needed to charge the storage that will serve on-peak loads, and to provide adequate savings to incent the beneficial daily cycling of storage.

Distributed solar provides customers with an on-site source of economical off-peak energy, for customers who want a competitive alternative to utility power, who want to be served with a higher percentage of renewable generation, or who want an on-site source of electricity to improve the resiliency of their electric service.

Q: Is there evidence that customers who invest in one type of DER – for example, an EV – are likely also to invest in other types of DERs, such as solar?

A: Yes. Based on discovery responses from the IOUs, there is a significant overlap in EV and solar customers, as illustrated by the fact that 34% of EV customers also have solar. This is more than three times the penetration of solar among all customers.[89]

Q: Will the GACs and low export rates that the Joint IOUs, PAO, TURN, and NRDC propose encourage or discourage customers who have increased their electric loads

[89] In data responses to SEIA / Vote Solar, the Joint IOU's provided: (1) the number of residential customer accounts in 2018-2020 and in 2021 to date that are on an EV rate (response to SEIA VS-Joint IOUs-006, Question 4), and (2) the number of such accounts that are also NEM customers (SEIA VS-Joint IOUs-006, Question 5). Our review of these responses indicates that 34% percent of all IOU residential EV customers in 2021 are also NEM customers. This percentage has grown from 27% in 2018. It ranges in 2021 from as low as 24% for SCE to as high as 44% for SDG&E; for PG&E, the percentage of EV customers that are also NEM customers is equal to the IOU average of 34%.

– for example, by adding an EV and moving onto an electrification rate – from considering adding solar to serve a portion of their higher off-peak loads?

A: Those parties' proposals would strongly discourage EV customers from considering adding solar, as their proposed rate structures would undo the benefits that the EV customer would realize from the low off-peak electrification rates. For example, we have modeled a residential customer on PG&E's default E-TOU-C rate who uses 7,500 kWh per year, and adds an EV consuming 4,000 kWhs per year (see **Table 10**).

Table 10: *An EV Customer Adding Solar to Charge the EV*

Rate	Usage	Bill Savings	
1. 7,500 kWh customer			
	kWh/month	$/month	$/kWh
E-TOU-C	625	179	0.286
2. 7,500 kWh customer adds 4,000 kWh EV			
	kWh/month	$/month	$/kWh
E-TOU-C	958	282	0.294
Increase	333	103	0.309
EV2A	958	241	0.252
Increase	333	62	0.186
Savings vs. E-TOU-C		*41*	
3. Solar = 90% of Annual Usage			
	kWh/month	$/month	$/kWh
Joint IOU: E-DER	96	197	2.052
Savings	862	44	0.051
SEIA – VS: EV2A	96	103	1.073
Savings	862	138	0.160

If that customer switches to an electrification rate (EV2A), the customer will save about $41 per month compared to staying on E-TOU-C. But at that point, if the Joint IOU's E-DER rate is in place, the customer would have no reason to consider solar, as the addition of solar would force the customer to switch to the E-DER rate with its high GAC. The available bill savings would be just $44 per month, or about 5 cents per kWh of solar produced. But if the EV2A rate were the common rate platform for all DERs, under the SEIA – Vote Solar proposal with a 50% discount in the export rate, the customer would have a reasonable opportunity to save $138 per month, or 16 cents per kWh of solar produced. This would cover the solar system's costs, and provide the customer with an on-site source of off-peak power to charge the EV.

3. Climate extremes and electrification place a premium on resiliency

Q: Does resilient electric service become more important with electrification?

A: Yes, because more of a customer's primary energy use will come from electricity. Climate extremes are placing an ever-higher premium on resilient electric service, a premium which will only grow with electrification of more primary energy uses in transportation and buildings. Portable fossil backup generation is not a long-term solution due to the substantial carbon emissions, air pollution, and health & fire risks of BUGs. Distributed solar is the least-cost renewable generation source that can be scaled and sited on customers' premises to provide clean and resilient electric service in combination with batteries.

VI. ISSUE 5 – **Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should the timeline be for implementation?**

A: The Commission should adopt the SEIA – Vote Solar successor tariff, for the reasons set forth in our proposal, our opening testimony, and this rebuttal.

A. Implementation Timeline

Q: The Joint IOUs have proposed a complex schedule for implementing the NEM 3.0 successor tariff. Please summarize that process.

A: Joint IOUs' estimate that the implementation process could require 12 to 24 months from the time of a final policy order, given the extended periods that have been necessary to implement rate changes after recent GRC Phase 2 cases. What is problematic is the Joint

IOU proposal to set a date for the cutoff for NEM 2.0 eligibility "as soon as possible" after the policy order.[90] This would be a period that is as short as possible in which solar vendors would be required to update their marketing materials to reflect the new NEM 3.0 structure. Further, the Joint IOUs propose that customers who interconnect after the final decision, but before NEM 2.0 enrollment eligibility for new customers ends, should be provided a shorter legacy treatment tied to typical payback for NEM 2.0 customers (i.e. 3-7 years).[91] The Joint IOUs also propose that new customers who energize solar systems after the NEM 2.0 cut-off would be compensated initially based on NEM 2.0, but then transition to NEM 3.0 when it is finally implemented.[92]

Q: What are your concerns with their proposed process?

A: I accept the Joint IOUs' estimate that the implementation process could require 12 to 24 months from the time of a final policy order, given the extended periods that have been necessary to implement rate changes after recent GRC Phase 2 cases. The first problem with the IOU schedule is that it assumes that NEM 3.0 rates and compensation will be clear immediately after a policy order issues. This may not be the case here,[93] and was not the case with NEM 2.0, which made far less sweeping changes to solar compensation than have been proposed by all parties to this case. The important details in the implementing advice letters for NEM 2.0 were subject to debate among the parties, and those advice letters required four and a half months to be drafted, processed, and approved after D. 16-01-044 issued.[94] It is difficult to see that process requiring less time in this case. I note that Vote Solar and SEIA have designed their proposal to be easily implemented – it uses existing rates, and modifies NEM 2.0 export rates only through the application of a single percentage factor to the export rate.

---

[90] See Joint IOU testimony, at p. 182.
[91] *Ibid.*, at p. 183.
[92] *Ibid.*, at pp. 184-185.
[93] Some parties have called explicitly for an implementation phase of this proceeding. See, for example, TURN's proposal, at pp. 16-17 and 52-53.
[94] Decision 16-01-044 was issued on February 5, 2016; Resolution E-4792 implementing that order was approved on June 23, 2016.

The second issue is that a major update to the ACC will be underway in early 2022 and is scheduled to be before the Commission for decision in the second quarter of 2022. Many parties to this case are proposing to use values directly from the ACC as compensation under NEM 3.0. SEIA and Vote Solar strongly recommend against the direct use of ACC values, for the reasons discussed above. However, if the Commission goes down that path, the economics of NEM 3.0 will not be clear until the decision on the 2022 ACC major update is decided. Even then, of course, the ACC will be subject to contentious annual updates.

A third issue is that the Joint IOU proposal is not clear whether a customer initially compensated on NEM 2.0 and then transitioned to NEM 3.0 would have to pay back the additional compensation it received under NEM 2.0. There is also no plan for handling the possible serious consumer protection issue of ensuring that customers know that their compensation under NEM 2.0 is only temporary, what their ultimate NEM 3.0 compensation will be, and when NEM 3.0 compensation will begin. This consumer protection issue can be avoided if the cut-over to NEM 3.0 does not begin until the IOUs can implement the new program and bill customers under NEM 3.0.

For these reasons, solar vendors are unlikely to know what to inform customers about the economic impact of the new NEM 3.0 program until the new tariffs are implemented and the 2022 ACC is in place, in mid-2022. The subsequent education and information process also deserves adequate time – time which the utilities admit they will also need in order to modify their billing systems. Finally, significant consumer protection issues can be avoided if the cut-over to NEM 3.0 does not happen until the IOUs can bill customers under the NEM 3.0 structure and rates. For these reasons, the SEIA / Vote Solar implementation date of January 1, 2023 remains reasonable.

Q: What are the factors that would simplify the implementation of NEM 3.0?

A: The larger and more precipitate the changes to the successor tariff, the more difficult the implementation process will be. The transition will be easier if:

- Changes are phased in gradually over time.
- Existing electrification rates are used for NEM 3.0 customers.
- Structural changes are minimized – for example, the use of simple percentages of the existing NEM 2.0 export rates, as SEIA and Vote Solar have proposed.
- NEM 3.0 compensation does not have to be revised completely each time the ACC is updated.
- The cut-over to NEM 3.0 should not begin until the IOUs can implement it. This will avoid the potential serious consumer protection and possible backbilling issues associated with the IOU proposal to allow solar customers to start service under NEM 2.0 but then to require them to switch to NEM 3.0 when it is finally implemented.

VII. ISSUE 6 – **Other issues that may arise related to current net energy metering tariffs and sub-tariffs, which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the NEM fuel cell tariff.**

A: SEIA and Vote Solar's NEM 3.0 proposal includes the still-developing opportunities for solar-plus-storage systems to provide a variety of grid services. This includes supplying dispatchable capacity for the resource adequacy (RA) market, providing distribution deferral capacity, and enhancing the ability of customers to participate in dynamic rate programs. California now has, in place, an established industry of DG and DER providers that would like to work with the Commission, the utilities, and other stakeholders to develop these important new opportunities. That will only happen, of course, if state policy continues to sustain a viable and vibrant market for the full range of DERs, including those that produce and store energy as well as those that consume it.

Q: Does this conclude your rebuttal testimony in this case?

A: Yes, it does.