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 Energy Metering.	R.20-08-020 (Filed August 27, 2020)

REBUTTAL TESTIMONY OF BILL POWERS, P.E.

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Introduction

This rebuttal testimony makes the following arguments:

- The NEM 2.0 residential and non-residential tariffs should be retained in their current form, supplemented by terms consistent with the proposals of CALSSA or SEIA/Vote Solar to incentivize inclusion of battery storage with NEM systems.
- Contrary to the assertions in the opening testimonies of the Joint IOUs, Cal Advocates, and TURN, rising residential rates are driven by rapidly increasing IOU transmission and distribution (T&D) investments and tiered rate restructuring, not a NEM cost shift.
- The cost-of-service calculation methodology best represents the cost shift between NEM and non-NEM customers.
- Neither the cost-of-service methodology nor the avoided cost methodologies preferred by other parties account for the cost benefit of proposed T&D projects that have been—or would be—eliminated by NEM solar.
- Contrary to the assertions of various other parties, there is no cost-shift associated with non-residential NEM, nor is there a cost-shift associated with residential

NEM when the cost benefit of proposed T&D that is eliminated by NEM solar is accounted for.

Bill Powers, P.E., is a registered professional engineer with a background in power systems who has served as an expert witness in numerous Commission proceedings. His resume is included as Attachment 1.

Issue 2: What information from the NEM 2.0 Lookback Study should inform the successor tariff and how should the Commission apply those findings in its consideration?

The following sections of this testimony respond to Issue 2 identified in the Scoping Memo. As discussed in these sections, the IOUs, TURN, and Cal Advocates improperly calculate the alleged cost burden imposed by NEM solar and fail to account for the full benefits of NEM. The Commission should not accept these parties' calculation of NEM solar's cost shift and should instead prioritize the results of the full cost of service analysis contained in the NEM 2.0 Lookback Study.

I. The Commission should prioritize the results of the full cost of service analysis from the NEM 2.0 Lookback Study, which estimates a substantially smaller cost-shift.

A. The Testimony Submitted by the IOUs, Cal Advocates, and TURN does not accurately characterize the cost burden of NEM solar.

The Joint IOUs, the Public Advocates Office ("Cal Advocates"), and TURN have cherry-picked extreme avoided cost calculation methodologies to assert that residential NEM customers are causing billions in shifted costs, but they ignore the results of the "full cost of service" analyses that undercut their massive-cost-shift argument.[1]

[1] R.20-08-020, TURN, Direct Testimony of Michele Chait on Net Energy Metering Reform Proposals (June 18, 2021) ("TURN Opening Testimony"), p. 9; R.20-08-020, Joint IOUs, Joint Opening Testimony of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company on Issues 2-6 of Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding

The first review of NEM impacts on ratepayers was conducted by E3 and completed in October 2013.[2,3] This study quantified the one legislatively-mandated cost test defined in AB 2514 for NEM solar, "full cost of service,"[4] as well as the marginal cost change using avoided cost methodologies.[5] Full cost of service is an IOU term that includes all utility costs, including an appropriate share of utility fixed costs to serve the customer.[6] E3 qualitatively described the results of the 2013 NEM full cost of service analysis in the following manner:[7]

> We find that, in aggregate, NEM customers pay amounts close to their full cost of service. In general, the non-residential accounts continue to see bills that substantially exceed their full cost of service.

Principles (June 18, 2021) ("Joint IOUs Opening Testimony"), p. 15; R.20-08-020, Public Advocates Office, Prepared Testimony for a Successor Tariff to the Current Net Energy Metering Tariffs (June 18, 2021) ("Cal Advocates Opening Testimony"), p. 2-17.

[2] E3, *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared for CPUC, October 28, 2013. (Attachment 2)

[3] The NEM ratepayer impacts study was ordered in D.12-05-036 (May 24, 2012). D.12-05-036 was vacated by D.13-11-026 (November 14, 2013). The Commission was mandated to conduct a full cost of service analysis of NEM solar by AB 2514 (signed into law on September 27, 2012). The section of AB 2514 requiring the study was repealed on October 1, 2017.

[4] E3, *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared for CPUC (Oct. 28, 2013), p. 83. "As required by AB 2514 (Bradford), we estimate the degree to which NEM customers pay their share of utility costs, or 'full cost of service.' To do this, the following analysis compares NEM customer bills to their share of utility costs as defined by an approximation of NEM customer full cost of service." (Attachment 2)

[5] Ibid, p. 84. "[T]he avoided cost approach evaluates the marginal cost change associated with the change in usage due to DG, whereas the full cost approach evaluates the total cost to serve the remaining NEM account usage (net usage). Moreover the full cost of service considers all utility costs, including fixed and historical utility costs, rate surcharges, balancing and memorandum accounts, and costs that are directly attributable to a particular customer or customer group, whereas the avoided cost approach only considers marginal costs."

[6] Ibid, p. 4.

[7] Ibid, p. 101.

E3 actually found a modest cost-shift from NEM customers in aggregate to the IOUs in the full cost of service analysis.[8]

The NEM 2.0 Lookback Study by E3 and Verdant also includes a full cost of service analysis. This full cost of service analysis determined, for the 2019 study year, that non-residential NEM customers were paying about $117.5 million per year more to the IOUs than the IOUs' full cost to serve those non-residential NEM customers.[9] Residential NEM customers were paying $618.6 million per year less to the IOUs that the IOUs' full cost to serve those residential NEM customers.[10] Taken together, NEM solar customers were paying approximately $500 million less to utilities than the full cost of service.

The Joint IOUs, Cal Advocates, and TURN simply ignore the full cost of service results, and instead focus exclusively on the much higher cost-shift values obtained by relying on avoided cost methodologies.

The Joint IOUs identify a current NEM cost shift of $3.4 billion annually. This value appears thirteen times in the Joint IOUs' opening testimony, and it is driven by the Joint IOUs' use of the revised draft results of the 2021 Avoided Cost Calculator, which dramatically changed the avoided cost of NEM solar relative to the costs determined by the 2020 Avoided Costs Calculator.[11, 12] There is no mention or analysis in the Joint IOUs' opening testimony of the full

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[8] Ibid, Table 48, p. 100. Aggregate NEM customer cost shift to IOUs = $11.872 million per year.

[9] Verdant Associates, LLC, Net Energy Metering 2.0 Lookback Study (Jan. 21, 2021), Figure 1-2, p. 11.

[10] Ibid, Figure 1-3, p. 12.

[11] Joint IOUs opening testimony, p. 64. The 2021 Avoided Cost Calculator was subsequently approved in Resolution E-5150 on June 24, 2021 (R.14-10-003).

[12] R.14-10-003, Resolution E-5150 (June 24, 2021), pp. 11-15 (summarizing comments of SEIA/VS and CALSSA).

cost of service analysis in the NEM 2.0 Lookback Study, or that the full cost of service study by E3 and Verdant found an aggregate NEM cost shift of approximately $500 million per year, not $3.4 billion per year.[13]

This is also true of Cal Advocates and TURN. Cal Advocates uses a similar avoided cost calculation process to that of the Joint IOUs to assert essentially the same NEM cost shift of $3.37 billion in 2021.[14] Cal Advocates and TURN each make only one mention of the full cost of service analysis in the NEM 2.0 Lookback Study, and only to underscore the amount of costs (in percent) not paid by NEM customers relative to the IOU's costs to serve those NEM customers.[15] Cal Advocates does not mention that the full cost of service NEM cost-shift calculated by E3 and Verdant was $500 million per year, or that the non-residential NEM full cost of service analysis found that non-residential NEM shifted costs in the opposite direction (i.e., to non-residential NEM participants). The $500 million per year full cost of service cost-shift calculated by E3 and Verdant is nowhere close to the $3.37 billion per year cost-shift that is repeated like a drumbeat in Cal Advocates' opening testimony.

B. The Residential NEM Cost-Shift Estimate Derived from Assumptions in the Haas Report Is Consistent with NEM Full Cost of Service Cost Shift Estimate in the NEM 2.0 Lookback Study

A recent report by the Energy Institute at Haas,[16] cited extensively by Cal Advocates, estimated the magnitude of the residential customer cost shift based on the fixed charge

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[13] Although the full cost of service analysis concerns data from 2019, while the avoided cost calculations concerns data from later years, the magnitude of the difference produced by the two methods as to the same years' data is likely similar.

[14] Cal Advocates Opening Testimony, p. 2-22.

[15] Ibid, Table 3-9, p. 3-31; TURN Opening Testimony, p. 10, footnote 15.

[16] Severin Borenstein, Meredith Fowlie, and James Sallee, "Designing Electricity Rates for an Equitable Energy Transition" (Feb. 2021) ("Haas Report").

component of residential rates assessed by PG&E, SCE, and SDG&E as shown in Table 1. The number of residential NEM solar systems in each of these IOU service territories is shown in Table 2. The average California residential customer consumed 6,385 kWh/yr of electricity in 2019.[17]

Table 1. Average 2019 retail residential rates, PG&E, SCE, and SDG&E[18]

Utility	2019 average retail residential rates, $/kWh	Fixed charge component of residential rate,[19] $/kWh
PG&E	0.23[20]	0.16
SCE	0.20[21]	0.12
SDG&E	0.26[22]	0.16

Table 2. Residential NEM systems, December 31, 2019

Utility	Number residential NEM customers[23]
PG&E	434,826
SCE	327,457
SDG&E	166,294

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[17] EIA, California Electricity Profile – 2019, November 2, 2020, Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2019: https://www.eia.gov/electricity/state/california/. Average 2019 California residential customer consumption = 87,523,987,000 kWh/yr ÷ 13,707,126 residential customers = 6,385 kWh/yr. (Attachment 3)

[18] Haas Report, Figure ES-2a-c Residential Price Decomposition ($/kWh) for 2019, p. 6.

[19] Ibid, Figure 4a-c Residential Price Decomposition ($/kWh) for 2019, p. 26.

[20] January 1, 2019, PG&E residential rate sheet. (Attachment 4)

[21] SCE and PRIME Joint Rate Comparison Effective January 1 2019: https://www.sce.com/sites/default/files/inline-files/SCE%20and%20PRIME%20Joint%20Rate%20Comparison%20Effective%20January%201%202019_0.pdf. General SCE residential rate, effective January 1, 2019 = $0.19691. (Attachment 5)

[22] CPUC, *2019 Senate Bill 695 Report – Actions to Limit Utility Cost and Rate Increases*, p. 17, footnote 17. (Attachment 6)

[23] California Distributed Generation Statistics, Statistics & Charts, accessed June 4, 2021: https://www.californiadgstats.ca.gov/charts/. (Attachment 7)

Accepting for the sake of argument the Haas Report's assessment that the IOUs' cost-recovery gap is reflected by the fixed charge component of the IOUs' residential rates, and assuming conservatively that every residential NEM solar system provides 100 percent of the NEM customer's annual electricity demand, the actual cost recovery gap attributable to NEM customers is a fraction of the $3.4 billion per year cost-shift alleged by the IOUs and Cal Advocates, as shown in Table 3.[24] In fact, the gap attributable to residential NEM solar customers, using the Haas Report's estimates of fixed-costs shifted from NEM customers to non-NEM customers, would be approximately $750 million in 2019. This conservatively-estimated cost-shift, about $750 million per year, is similar in magnitude to the full cost of service cost-shift of $618.6 million per year calculated in the E3 and Verdant NEM 2.0 Lookback Study for residential NEM in 2019. Thus, the February 2021 Haas Report actually reinforces the appropriateness of relying on the full cost of service analysis in the Lookback Study to assess the magnitude of the cost shift.

Table 3. IOU Gap in Fixed Charge Recovery from Residential NEM systems, 2019
(assume all NEM systems supply 100% of net annual energy usage)

Utility	Number residential NEM customers[25]	Avoided usage, kWh/yr	Avoided unit fixed charge, kWh	Current fixed charge per NEM customer, $/yr	Net "gap" in fixed charge collection, $/yr
PG&E	434,826	6,385	0.16	120	392 million
SCE	327,457	6,385	0.12	120	212 million
SDG&E	166,294	6,385	0.16	120	150 million
				Total:	754 million

[24] Table 5 calculates this actual cost recovery gap by multiplying the total number of NEM customers by the average electrical usage by the fixed rate component of the IOU's residential rates minus the current fixed charge per NEM customer. PG&E example: (434,826 customers x [(6,385 kWh/yr x $0.16/kWh) – $120/yr] = $392,039,122/yr.

[25] California Distributed Generation Statistics, Statistics & Charts, accessed June 4, 2021: https://www.californiadgstats.ca.gov/charts/.

C. The Lookback Study, the Joint IOUs, Cal Advocates, and TURN Gloss Over the Causes of Rising Retail Electricity Rates, While Assigning Responsibility for Rate Increases to NEM Solar.

In addition to inappropriately characterizing the cost shift, the Lookback Study and the parties listed above misdiagnose the cause of increasing retail electricity rates. For example, Cal Advocates implies that the NEM cost shift is an important contributor to rising retail rates, stating:[26]

> Retail electricity rates are rising, and NEM is responsible for a significant portion of these increases.

Cal Advocates' description of why retail electricity rates are rising is incomplete. For example, the restructuring of residential tariffs following passage of AB 327 has had a much bigger impact than the NEM solar cost-shift calculated by E3 and Verdant using the cost of service methodology.

A December 2017 Office of Ratepayer Advocates (now Cal Advocates) analysis of SDG&E rates determined that the summertime residential baseline rate for the non-CARE customers increased 55 and for CARE customers 48 percent in less than three years, from January 2015 to November 2017, after implementation of rate-flattening combined with rate increases. [27]

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[26] Cal Advocates Opening Testimony, p. 3-8.

[27] Office of Ratepayer Advocates, *Protest of the Office of Ratepayer Advocates of SDG&E's Advice Letter 3137-E – Annual Electric Regulatory Account Update for Rates Effective January 1, 2018* (Dec. 4, 2017), Table 3, p. 5. (Attachment 8)

This translates into an annual average monthly bill increase of 26 percent, or $32/month, for non-CARE SDG&E customers using an average amount of electricity (532 kWh/month).[28] The monthly bill for SDG&E CARE customers using an average amount of electricity increased with the two-tier rate structure by about 33 percent, with a monthly bill increase of $24/month.[29] These residential bill increases attributable to the two-tier rate structure were far greater than forecast by proponents of this rate structure.[30]

The 26 percent increase in non-CARE customer rates and the 33 percent increase in CARE customer rates caused by implementation of the two-tier rate structure is much greater than the 13 percent increase in SDG&E CARE customer bills that the Commission asserts is due to the NEM solar cost shift.[31] Additionally, rapidly rising transmission and distribution (T&D) fixed costs are the primary contributor to rapidly rising retail residential rates, not the NEM 2.0 tariff.

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[28] See Attachment 9 for calculations. Annual average residential usage = 6,385 kWh, per calculation in footnote 15. Annual average monthly usage = 6,385 kWh/yr ÷ 12 month/yr = 532 kWh/mo.

[29] See Attachment 9**.**

[30] S. Borenstein, *Rationalizing California's Residential Electricity Rates* (Sept. 29, 2014), available at https://energyathaas.wordpress.com/2014/09/29/rationalizing-californias-residential-electricity-rates/. "Overall, I estimate that moving to a flat-rate tariff would raise the average bill of a customer making about $50,000/year or less (in today's dollars) by about $5/month." (Attachment 10)

[31] CPUC, *Utility Costs and Affordability of the Grid Of The Future* (Feb. 2021), p. 29. "As of November 2020, SDG&E had approximately 199,000 residential NEM customers and 320,000 CARE customers. Of these CARE customers, only 8 percent are NEM participants. CARE customers are currently seeing bills that are 13 percent higher as a result of the NEM cost shift." (Attachment 11)

D. Some Degree of Cost-Shifting Occurs Among All Customer Classes and is Not Unique to NEM; but NEM Uniquely Threatens the IOU Business Model.

The Joint IOUs, Cal Advocates, and TURN are silent in their opening testimony on the fact that cost-shifting among customer groups is an inherent aspect of ratemaking. E3 makes this observation in the 2013 NEM ratepayer impacts study regarding cost-shifting generally, that there are cost shifts throughout customer classes, and not just with NEM customers:

> Full cost of service is a regulatory construct that refers to the total amount of revenue that a customer group would pay relative to other customer groups, based on how that group imposes costs on the utility. There are numerous steps in the ratemaking process that result in all customers, not just NEM customers, paying bills that differ from their actual full cost of service.[32]

The Joint IOUs, Cal Advocates, and TURN misrepresent this generalized cost-shifting between customer groups by presenting the alleged NEM cost shift as a phenomenon unique to the residential NEM 2.0 tariff that must be rectified through a less favorable NEM tariff.

Although all ratemaking typically involves shifting costs from one ratepayer group to another, NEM is unique in the threat it poses to the traditional IOU business model. As noted by the Environmental Working Group, "the fact that the utility business model relies on making a return on large capital intensive investments in transmission lines . . . gives them an incentive to push out any competitors that lessen the need for such lines."[33]

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[32] E3, *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared for CPUC (Oct. 28, 2013), p. 83. (Attachment 2)

[33] R.20-08-020, Prepared Direct Testimony of Ken Cook on behalf of the Environmental Working Group (June 18, 2021) ("EWG Opening Testimony"), p. 34.

The IOU's trade association, Electric Institute (EEI), identified NEM solar as an existential threat to the IOU cost-of-service model in 2012.[34] Subsequently, EEI worked with the American Legislative Exchange Council (ALEC) to prepare sample anti-NEM solar bill language and distribute it to state legislatures around the country.[35, 36] California IOUs are major donors to EEI.[37]

AB 327 (2013) was originally similar in intent, anti-NEM solar legislation introduced with IOU support to undercut the economic benefits of NEM solar by the flattening of residential

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[34] Environment America, *Blocking the Sun - 12 Utilities and Fossil Fuel Interests That Are Undermining American Solar Power* (Oct. 2015), p. 4. "The Edison Electric Institute (EEI), the trade group that represents U.S. investor-owned electric utilities, launched the current wave of anti-solar advocacy with a 2012 conference warning utilities of the challenges solar energy posed to their traditional profit centers. Since then, EEI has worked with the American Legislative Exchange Council (ALEC) on model legislation to repeal state renewable electricity standards and ran an anti-solar public relations campaign in Arizona. ALEC provides utility and fossil fuel interests with access to state legislatures, and its anti-net metering policy resolution has inspired legislation in states like Washington and Utah." (Attachment 12)

[35] Ibid, p. 12.

[36] Energy and Policy Institute, *The Campaign Against Net Metering: ALEC and Utility Interests' Next Attack on Clean Energy Surfaces in Arizona* (Nov. 18, 2013): https://www.energyandpolicy.org/campaign-against-net-metering-alec-utility-interests-arizona/. "Arizona Public Service (APS) had proposed charging customers who install rooftop solar panels an additional $50-100 on their monthly bills . . . According to solar companies operating in the state, APS was attempting to "tax the sun," and APS's proposed changes would have "erase[d] the financial incentive for using solar." . . . APS appears to be leading the first assault of a national campaign by the utility industry trade association, Edison Electric Institute (EEI), and fossil fuel interests like APS, to weaken net metering policies." (Attachment 13)

[37] The most recent IOU GO-77 executive compensation and contribution reports are available on a dedicated CPUC webpage, accessed June 13, 2021: https://www.cpuc.ca.gov/General.aspx?id=6442454119. SDG&E 2019 GO-77, p. 38 and p. 56, SDG&E paid EEI $1.843 million in dues and contributions in 2019; PG&E 2018 GO-77, p. 118, PG&E paid EEI $2.263 million in dues and contributions in 2018; SCE 2018 GO-77, p. 92, SCE paid EEI $1.871 million in dues and contributions in 2018.

rates and adding substantial monthly fixed charges.[38] Strong opposition resulted in a final bill that, although it did flatten residential tiered rates and did add a $10 per month fixed fee, it also facilitated NEM solar expansion.

EWG also correctly identifies the need to revise the IOU financial structure to accommodate DERs.[39] This has already occurred in Hawaii, where performance-based regulation (PBR) has superseded traditional IOU cost of service regulation.[40] The Commission has just initiated a proceeding, R.21-06-017, "Order Instituting Rulemaking (OIR) to Modernize the Electric Grid for A High Distributed Energy Resources Future." The OIR observes that the Hawaii PUC adopted in December 2020 a PBR framework to incentivize DER deployment,[41] in the context of whether California's IOUs should be incentivized to prepare for widespread DER deployments.

NEM's potentially negative implications for the long-term viability of the IOU business model also casts doubt on the neutrality of E3, the Commission's consultant responsible for preparation of white papers supporting this proceeding and the 2021 ACC. E3 works directly as a

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[38] Greentech Media, *AB 327: From California Solar Killer to Net Metering Savior?*, September 3, 2021: https://www.greentechmedia.com/articles/read/ab-327-from-california-solar-killer-to-net-metering-savior. (Attachment 14)

[39] EWG Opening Testimony, p. 42. "EWG believes that the Commission needs to ask itself whether the centralized utility model remains the right one to successfully meet California's climate goals, serve low-income communities, provide both reliability and resilience, minimize wildfire risks, minimize land use impacts, and ultimately provide enough value to rate payers."

[40] Hawaii PUC press release, *Hawaii PUC Approves Portfolio of Performance Mechanisms for Hawaiian Electric* (June 1, 2021), available at https://puc.hawaii.gov/wp-content/uploads/2021/06/PBR-PIM-DO-Press-Release.Final_.V2.06-01-2021.pdf. (Attachment 15)

[41] R.21-06-017, CPUC, Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (July 2, 2021), p. 17, footnote 39.

consultant for the IOUs as well. E3's clients in California, beyond the CPUC and California Energy Commission (CEC), include PG&E, SCE, SDG&E, SoCalGas, Sempra, and utility-scale solar developers Brightsource and First Solar.[42,43] Working for the regulators of the California IOUs, the California IOUs themselves, and private developers with a financial stake in the outcome of the Commission's determination regarding the NEM cost shift is a conflict of interest that calls into question E3's role as a neutral technical resource.

II. The Joint IOUs, Cal Advocates, and TURN Do Not Account for the Full Benefits of NEM Solar.

The analyses presented by the parties asserting a significant NEM cost-shift do not account for the full benefits of NEM Solar. As described in the following sections, these benefits include eliminated transmission costs, avoided distribution costs, and avoided wildfire mitigation costs. When the value of these benefits is fully accounted for, the size of the alleged cost shift greatly diminishes, if not disappears.

[42] Public Service Commission of South Carolina, Docket No. 2019-182-E, *Direct Testimony and Exhibits of Brian Horii (Senior Partner E3) on Behalf of the South Carolina Office of Regulatory Staff*, Re: South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators, October 8, 2020, Exhibit BKH-1, p. 1 of 7. "His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra (SDG&E and SoCalGas), Southern California Edison, and South Carolina Office of Regulatory Staff." (Attachment 16)

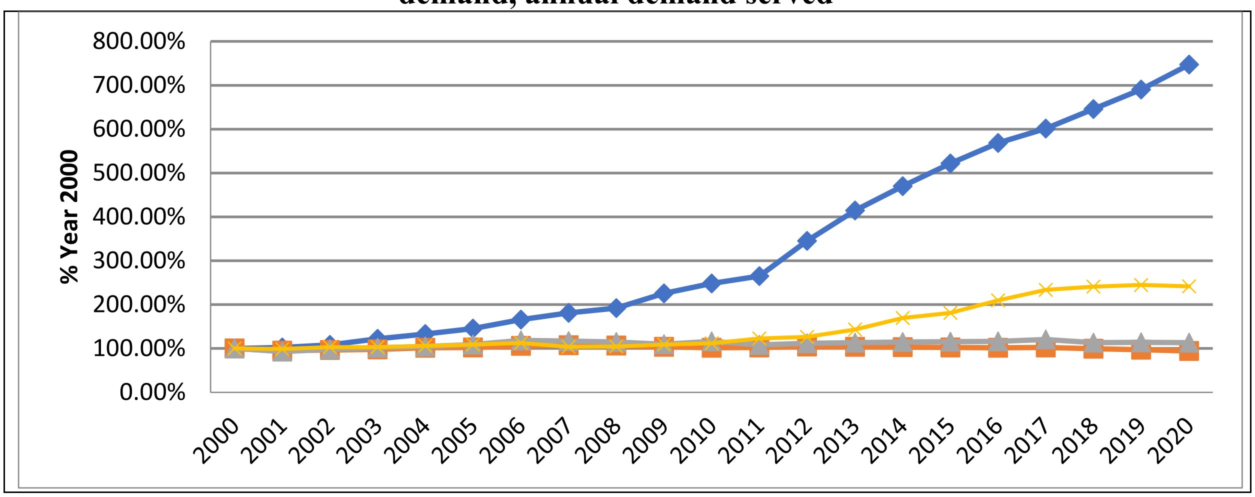
[43] A.09-05-027, *Application of SCE for a Certificate of Public Convenience and Necessity for the Eldorado-Ivanpah Transmission Project – Rebuttal Testimony of Arne Olson (E3) on Behalf of Brightsource Energy, Inc. and First Solar, Inc.* (July 30, 2010). (Attachment 17)

A. The Parties Asserting a Significant Cost Shift Do Not Account for NEM Solar's Value in Eliminating New Transmission Capacity.

1. IOU Investments in New Transmission Are Driving Rate Increases.

Agricultural Energy Consumers Association (AECA) and the California Farm Bureau Federation (CFBF) observe that "Peak loads in the CAISO balancing authority reach[ed] their highest point in 2006 and the peak last August (2020) was 6% below that level."[44] Yet IOU investments in new transmission have increased at a spectacular rate since CAISO took over the role of transmission planning and approval in 1998. Figure 1 compares the growth trends from 2000 to 2020 in transmission asset value (blue), RPS energy production (yellow), non-coincident peak load (gray), and annual demand served (orange).

Figure 1. Comparison of growth trends – transmission value, RPS production, peak demand, annual demand served[45]



[44] R.20-08-020, Testimony of Richard McCann, Ph.D, On Behalf of the Agricultural Energy Consumers Association and the California Farm Bureau Federation (June 18, 2021) ("AECA and CFBF Opening Testimony"), p. 9.

[45] J. Firooz, *Is the CAISO Bringing Benefits to California Consumers? 2019 Update to 2010 Assessment* (Jan. 8, 2019), graphics updated June 21, 2021, available at http://protectourcommunities.org/wp-content/uploads/2021/06/2021-06-21_data-revisions_J-Firooz_Is-the-CAISO-bringing-benefits-to-california-consumers-2019-update.pdf. (Attachments 18 and 19)

The increase in IOU transmission asset value from 2007, the year after the highest recorded peak year of 2006, to 2020 is $22.1 billion.[46] The annualized transmission cost factor for PG&E is 0.1046.[47] Using the PG&E annualized cost factor as representative, the annualized IOU transmission charges to ratepayers have risen by approximately $2.3 billion per year since 2007. This is over four times higher than the $500 million per year NEM solar cost of service cost shift identified by E3 and Verdant in the Lookback Study.

The current impact of transmission asset cost recovery on an SDG&E residential bill is $0.0644/kWh.[48] The SDG&E transmission charge on a residential bill was $0.005/kWh in 2001,[49] less than one-tenth the current SDG&E residential transmission charge.

The three California IOUs added $20 billion in new transmission from 2010-2019,[50] with $5.3 billion of new capital additions projected for 2020 and 2021.[51] A substantial portion of this new transmission capacity has been self-approved, with no review of need or cost by the

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[46] Ibid, updated Table 1 (data through 2020). $29,180,149,369 - $7,079,788,862 = $22,100,360,507. (Attachment 19)

[47] E3, *2021 Distributed Energy Resources Avoided Cost Calculator Documentation* (June 22, 2021), p. 46. Annual MC Factor = 10.46%.

[48] SDG&E, SCHEDULE TOU-DR1, residential time-of-use effective June 1, 2021 (Submitted May 13, 2021), p. 3: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_TOU-DR1.pdf. (Attachment 20)

[49] J. Firooz, *Is the CAISO Bringing Benefits to California Consumers? 2019 Update to 2010 Assessment*, (Jan. 8, 2019), p. 3, footnote 2: http://protectourcommunities.org/wp-content/uploads/2021/06/2019-01-08-J-Firooz-2nd-CAISO-Paper_Final-Draft.pdf. (Attachment 18)

[50] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), Table 11, p. 39. Total Capital Additions, 2010-2019 = $19.99 billion. (Attachment 11)

[51] Ibid, p. 39. "The annual capital additions projected for just 2020 and 2021 total $5.3 billion, with approximately 60 percent being self-approved projects across all three IOUs, with PG&E exceeding 80 percent self-approved."

Commission or CAISO.[52] However, the rate impact of this transmission expansion would have been even higher without NEM solar.

2. The IOUs, Cal Advocates, and TURN Fail To Quantify Eliminated Transmission Benefits.

Despite these rising transmission costs, the Joint IOUs, Cal Advocates, and TURN all rely on the E3 and Verdant Lookback Study and the 2021 ACC to support their NEM cost-shift arguments. However, the Lookback Study and the 2021 ACC assign no monetary benefit to the demonstrated value of NEM solar to eliminate new transmission capacity. Only the avoided cost of deferred transmission capacity is accounted for in the 2021 ACC and the Lookback Study, not the avoided cost of previously proposed new transmission capacity that was eliminated by the growth in NEM solar and never built.[53] That avoided cost is quantified later in this rebuttal testimony.

The failure of the Lookback Study or the ACC to assign a monetary value to NEM solar's demonstrated role in eliminating new transmission capacity undermines claims by the Joint IOUs, Cal Advocates, TURN, and NRDC of a residential NEM cost shift. This omission skews both the NEM full cost of service analysis and avoided cost analyses in the E3 and Verdant Lookback Study. Accurate accounting of proposed new transmission that was actually eliminated – not just deferred – by NEM solar would offset a substantial component the cost of service cost-shift of about $500 million per year identified in the Lookback Study.

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[52] Ibid, pp. 38-39.

[53] CAISO, *R.14-08-013 Reply Comments of the California Independent System Operator Corporation* (Aug. 23, 2019), p. 4. "CAISO believes developing a generic or system-wide transmission avoided cost is not feasible." (Attachment 21)

D.20-03-005, *Decision Adopting Staff proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values (March 12, 2020)*, sidestepped the issue of NEM solar's role in eliminating new transmission, stating "this decision does not draw a conclusion regarding the unspecified transmission deferral value."[54] This meant that the status quo – not quantifying NEM solar's demonstrated role in avoiding new transmission capacity intended address peak load growth – would stand.

However, D.20-03-005 made clear that NEM solar's role in eliminating transmission projects specifically planned to facilitate RPS compliance is a separate type of specific avoided transmission cost that must be considered in NEM solar cost-effectiveness calculations.[55] The ACC is not configured to quantify the added value of NEM solar as an alternative to new transmission built for RPS compliance purposes.[56]

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[54] D.20-03-005, Decision Adopting Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values (Mar. 12, 2020), p. 1.

[55] Ibid, pp. 5-6. "Specified deferral value: . . . Deferral value is generally associated with capacity-related projects whose need can be affected by changes in peak demand. Value associated with deferring specific infrastructure identified as needed for other purposes (i.e. greenhouse gas reduction, renewables portfolio standard compliance, or economic benefits) is a conceptually separate type of value and is excluded from this definition <u>but not from consideration in cost-effectiveness calculations</u>."

[56] Ibid, p. 6. "Specified (T&D) deferral value has been most associated with targeted Distributed Energy Resource procurement. The Distribution Investment Deferral Framework was developed in Rulemaking (R.) 14-08-013 to accomplish this goal. Meanwhile, unspecified deferral value has been most commonly associated with providing inputs to the Avoided Cost Calculator, which is then used to inform the evaluation of the cost effectiveness of various Commission-supported demand-side programs such as net energy metering. These values reflect non-targeted Distributed Energy Resource deferral."

3. The Cost Benefits of NEM Solar Eliminating Transmission Reduce the Cost-Shift.

NEM solar is eliminating expansion of the T&D system that would otherwise be necessary to accommodate load growth and congestion, and not only deferring T&D expansion that will inevitably occur. This was most recently demonstrated when CAISO identified the unexpected growth in NEM solar as a primary reason CAISO cancelled $2.6 billion in proposed transmission projects in PG&E service territory in 2018 at the end of a three-year review of PG&E transmission expansion proposals.[57,58]

CAISO indicates that a perceptible impact of NEM solar on peak loads was first observed in 2015 by the California Energy Commission (CEC).[59] CAISO utilizes the CEC load forecasts in its transmission planning process. A projected increase in peak load is a principal justification

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[57] CAISO press release, *Board approves 2017-18 Transmission Plan, CRR rule changes* (Mar. 23, 2018), available at http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf. "The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation." (Attachment 22)

[58] CAISO, *2017-2018 ISO Transmission Plan* (Mar. 22, 2018) ("2017-2018 TPP") pp. 2-3, available at http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf. "In this third year of a comprehensive review of previously-approved projects in the PG&E service territory, the ISO built on study efforts in previous cycles and not only identified projects that were no longer needed, but also explored re-scoping a significant number of projects to better reflect evolving needs. As a result of the review, 18 projects are recommended to be canceled, and major scope changes have been identified for 21 other projects, paring over $2.6 billion from the ISO transmission capital program estimated costs. Seven other projects will continue to be on hold pending reassessment in future cycles." (Attachment 23)

[59] Ibid, p. 17. "The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available. This is an issue that has been progressing through subsequent IEPR processes, having first been noted in the CEC's 2015 effort."

for new transmission projects.[60] In the three-year 2015-2017 time period, 1,685 MW of NEM solar was added in PG&E territory.[61] This NEM growth rate was much more rapid than assumed by CAISO.[62] The CEC forecast of NEM solar growth in PG&E territory for the 2015-2017 period was approximately 230 MW. [63,64] This is about 1,440 MW less than the actual addition of

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[60] R.14-10-003 (Integrated Distributed Energy Resources), *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (Oct. 7, 2019), p. 47. "The utilities and the CAISO often categorize transmission projects based on the principal reason for the project, such as:

• Load growth – serving peak demand
• Reliability – addressing N-1 or N-1-1 contingencies in high load hours
• Economic – relieving congestion, which typically occurs in high-demand hours
• Policy-driven – to meet RPS needs based on MWh goals
However, the transmission system is a network, and an addition that is made principally for one reason (for example, reliability) also will increase the system capacity to serve 10 load growth, as a secondary benefit. In addition, the first three of the above types of transmission projects (peak load growth, reliability, and economics) are directly or closely tied to peak demands on the grid, and all types of additions to the networked grid (including capacity to access new RPS resources) may contribute to serving peak demands. Further, renewable generation from DERs, or reduced load from demand response or energy efficiency measures, contribute equally with RPS generation (which may require new transmission) to meeting the state's long-term carbon reduction goals. As a result, the long-term avoided or deferred transmission costs associated with DERs should be calculated considering all investments in transmission." (Attachment 24)

[61] California Distributed Generation Statistics, Stats & Charts, PG&E, accessed June 18, 2021: https://www.californiadgstats.ca.gov/. PG&E NEM solar, December 31, 2014 = 1,160 MW; December 31, 2017 = 2,845 MW. NEM solar increase, 2015-2017 = 1,685 MW. (Attachment 25)

[62] 2017-2018 TPP, p. 16. "These trends, including higher than previously expected levels of behind-the-meter solar generation, are producing new and more complex operating paradigms for which the ISO must consider in planning the grid." (Attachment 23)

[63] NEM 2.0 Lookback Study, Table 1-1, p. 4. PG&E residential: average system size 5.9 kW_{DC}. Assume 85% DC-to-AC conversion efficiency, therefore 5.9 kW_{DC} = 5.015 kW_{AC}. Annual production = 9,696 kWh. Therefore unit annual production = 9,696 kWh ÷ 5.015 kW_{AC} = 1,933 kWh/kW_{AC}.

[64] California Energy Commission, Final California Energy Demand Update (CEDU) 2013 Forecast, PG&E Form 1-2-Mid, "PV", xls spreadsheet, November 2013. 2014 PV = 2,046 GWh; 2017 PV = 2,385 GWh. 2014 PV forecast in MW: 2,046,000 MWh ÷ 1,933 MWh/MW_{AC} = 1,058 MW. 2017 PV forecast in MW: 2,485,000 MWh ÷ 1,933 MWh/MW_{AC} = 1,286 MW. CEC

1,685 MW of NEM solar in PG&E territory in the 2015-2017 period. The amount of NEM solar installed in PG&E territory at the end of 2014 was also about 100 MW higher than forecast for 2014 by the CEC in November 2013.[65] The total net increase in NEM solar in PG&E territory in 2015-2017 above the CEC forecast was approximately 1,540 MW.[66]

The amount of energy efficiency (EE) peak load reduction targeted for PG&E territory in 2015-2017 is also known. PG&E's goals for EE-related peak load reduction were 154 MW for 2015, 226 MW for 2016, and 193 MW for 2017, a total of 573 MW for the three-year period.[67]

Peak load typically occurs in mid- to late afternoon, when a NEM solar system is no longer producing at maximum capacity. What must be calculated is the percentage of NEM solar capacity that is actually contributing to peak load reduction. This is known as the "peak capacity

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forecast increase in NEM PV in PG&E, 2015-2017 = 1,286 MW – 1,058 MW = 228 MW. (Attachment 26)

[65] California Distributed Generation Statistics, Stats & Charts, accessed July 13, 2021. PG&E NEM solar total at end of 2014 = 1,157 MW. See: https://www.californiadgstats.ca.gov/charts/. Net difference in PG&E NEM solar at end of 2014 compared to 2013 CEDU forecast for PG&E = 1,157 MW – 1,058 MW = +99 MW.

[66] PCF's Opening Testimony in this proceeding (at p. 4) refers only to the total NEM solar increase in PG&E territory of 1,685 MW between 2015-2017.

[67] D.14-10-046, *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs And Budgets* (Oct. 16, 2014), Figure 1, p. 10 (2015 peak savings goal = 154.4 MW); D.15-10-028, *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*, October 22, 2015, Table 2, p. 9 (2016 peak savings goal = 226 MW, 2017 peak savings goal = 193 MW). Total = 154 MW + 226 MW + 193 MW = 573 MW.

allocation factor," or PCAF.[68] In PG&E territory, the PCAF is approximately 35 percent.[69] The portion of the NEM solar added in 2015-2017 contributing to peak load reduction is 1,540 MW x 0.35, or about 540 MW. Based on the approximately equal 2015-2017 peak load reductions associated with new EE and NEM solar in PG&E territory, about one-half of the cancelled PG&E transmission project savings - $1.3 billion - are attributable to NEM solar.

The conversion of PG&E transmission capital cost expenditures that were avoided by NEM solar into an annualized cost allows calculation of transmission costs avoided by the addition of each new NEM solar project.[70] As shown in Table 4, assuming an average NEM solar system capacity of 6 kW_{AC}, each NEM solar system installed in PG&E territory in the 2015-2017 period avoided approximately $620/yr in new transmission cost.

Table 4. Calculation of PG&E avoided transmission expenditure value of NEM solar

Element	Calculation	Value
PG&E capital transmission costs avoided by NEM solar, 2018	--	$2.6 billion
Annualized cost of avoided new PG&E transmission[71]	($2.6 billion ÷ $1.883 billion) x $254 million/yr = $350 million/yr	$350 million/yr
NEM solar added in PG&E territory, 2015-2017	--	1,540 MW

[68] CPUC, Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update Integrated Distributed Energy Resources Rulemaking (R.14-10-003) (Apr. 16, 2020), p. 42. "Peak Capacity Allocation Factor (PCAF) Method. Peak reduction is the weighted average resource performance across hours in the peak period. The weights are relative to the project area demand in excess of a "peak threshold." The higher the demand, the higher the weight assigned to the hour to approximate higher need for capacity in the higher demand hours."

[69] 2020 Avoided Cost Calculator: PG&E PCAF, NEM solar only = 35%.

[70] The ratio of capital cost to annualized cost in the SDG&E's 500 kV Sunrise Powerlink (SPL) transmission line application is used as the point of reference to estimate the annual cost of $2.6 billion in new transmission capacity in PG&E territory. SPL capital cost = $1.883 billion. SPL annualized cost over 40 years = $254 million/yr.

[71] The annualized PG&E cost is extrapolated from the $254 million/yr annualized cost of SPL based on a SPL capital cost of $1.883 billion.

Avoided transmission capital cost and annual costs attributable to NEM solar	50% attributable to NEM solar, 50% attributable to EE	$1.3 billion capital, $175 million/yr annual
Number of residential NEM solar projects at 6 kW each, 2015-2017	1,685,000 kW ÷ 6 kW/project = 281,000 projects	281,000 projects
Annual value of avoided PG&E transmission per residential NEM project	$175 million/yr ÷ 281,000 projects = $623/yr/project	$623/yr/project

The calculated annual transmission savings of about $620/yr/system is for solar-only NEM systems, which is appropriate for the 2015-2017 time period being evaluated. However, it is now common for new NEM systems to include battery storage. Battery storage doubles the NEM system PCAF, from 35 percent to 70 percent.[72] This doubles the amount of NEM capacity available for peak load reduction, and increases the avoided transmission cost benefit of NEM solar.

The CPUC, in its April 2020 decision approving the 2020 Avoided Cost Calculator inputs, acknowledged qualitatively that NEM solar played a role in avoiding transmission costs but declined to monetize that avoided cost.[73] Monetizing the avoided cost of non RPS-related transmission projects that are cancelled because of NEM solar, assuming a benefit of approximately $620 per year per NEM solar system, would – by itself – largely eliminate the

[72] 2020 Avoided Cost Calculator: PG&E PCAF, solar + battery storage = 70%.

[73] D.20-04-010, 2020 Policy Updates to the Avoided Cost Calculator (Apr. 16, 2020), p. 60. "We acknowledge that distributed energy resources avoid transmission costs but, at this time, the record in this proceeding provides no reasonable alternate method of determining unspecified avoided transmission costs."

alleged residential NEM cost shift that the Joint IOUs and Cal Advocates attempt to address with fixed charges and severely reduced compensation for exported power.[74]

CAISO attempted to walk-back its statements in the 2017-2018 TPP regarding the roles of EE and NEM solar in eliminating $2.6 billion in PG&E transmission projects in its August 2019 reply comments in R.14-08-013.[75] CAISO expressed skepticism about efforts to calculate the avoided transmission cost attributable to NEM solar on a system-wide basis. This is despite having identified system-wide EE and NEM solar additions as the primary reasons for the transmission project cancellations in the 2017-2018 TPP.[76] CAISO erroneously implied that the DER estimate already embedded in the CEC forecast it uses for transmission planning was accurate.[77] In the 2017-2018 TPP, CAISO states that the increase in DERs (NEM solar) was unexpectedly high – relative to the CEC's NEM solar forecast – during the (3-year) study period. The Commission should give no weight to this ex post facto qualitative and non-factual effort by CAISO to disavow its statements in its 2017-2018 TPP regarding NEM solar's substantial role in eliminating $2.6 billion in transmission projects in PG&E territory.

B. The Cost-Shift Arguments Ignore the Cost Benefit of NEM Solar in Avoiding Rising Distribution Costs and Up To $40 Billion in Future Wildfire Mitigation T&D Expenditures

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[74] Haas Report, p. 40. "PG&E needs to recover almost $900 per household per year; SCE needs to recover around $700 per household per year; and SDG&E needs to recover around $850 per year."

[75] R.14-08-013, *Reply Comments of the California Independent System Operator Corporation* (Aug. 23, 2019). (Attachment 21)

[76] CAISO 2017-2018 TPP, pp. 16-19. (Attachment 23)

[77] R.14-08-013, *Reply Comments of the California Independent System Operator Corporation* (Aug. 23, 2019), p. 4. (Attachment 21)

1. Distribution Costs Are Driving Rate Increases.

AECA and CFBF accurately characterize IOU overbuilding of distribution infrastructure, while ignoring the benefits of NEM solar in reducing or eliminating the need for new distribution infrastructure:[78]

> Utilities' forecasts are notorious for overestimating load growth, resulting in part from underestimating savings from resource displacement through solar rooftops and energy efficiency. As a result, utilities build unneeded distribution infrastructure . . . That distribution planners are not considering this impact appropriately is not an excuse for failing to value this benefit.

Distribution infrastructure is not subject to need, cost, or environmental review.[79] Wildfire mitigation activities have been a recent major contributor to increases in fixed distribution costs. These costs are expected to rise dramatically in future years in all three California IOU service territories. The CPUC's February 2021 "*Utility Costs and Affordability of the Grid of the Future*" report observes that the CPUC authorized SDG&E to spend $1.7 billion on grid hardening and related wildfire mitigation activities in the 2007-2018 time period.[80] The

[78] AECA/CFBF Opening Testimony (McCann), p. 9.

[79] D.16-05-038, Decision Granting Permit to Construct the Cleveland National Forest Power Line Replacement Projects (May 26, 2016), p. 12. "D.94-06-014 implemented the PTC (permit to construct) process for the express and exclusive purpose of subjecting projects between 50 kV and 200 kV (but not those below 50 kV), that were previously exempt from any review under GO 131-C, to environmental review pursuant to CEQA. D.94-06-014 does not revisit the Commission's determination that projects with operating voltages at or below 200 kV should be exempt from a review of project need or project cost pursuant to Section 1005.5."

[80] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), p. 33. "After destructive fires in SDG&E's service territory in 2007, the CPUC approved SDG&E cost recovery applications for a total of about $1.7 billion dollars over the period 2007 – 2018 for grid hardening, situational awareness, and vegetation management to better address the risk of wildfires." (Attachment 11)

CPUC also notes that SDG&E wildfire mitigation costs have continued to increase, and that this trend may inform the future spending of PG&E and SCE as they ramp-up their wildfire mitigation programs and harden their systems.[81]

The total asset value of California IOU distribution infrastructure in 2000, 2003, 2007, 2010, 2018, and 2020 is shown in Table 5. This data is shown graphically in Figure 2. 2007 is the year of the devastating SDG&E wildfires that led to prioritizing wildfire mitigation activities in SDG&E service territory. That emphasis is reflected in distribution capital spending. For example, SDG&E's distribution plant asset value increased by $468 million in 2018.[82] Of this amount, $266 million, or 57 percent, were SDG&E wildfire mitigation capital expenditures.[83]

Table 5. IOU distribution plant asset value growth, 2000 - 2020

Year	IOU distribution plant asset value,[84] $			
	PG&E	SCE	SDG&E	Total
2000	11,144,168,346	7,691,213,604	2,272,491,415	21,077,873,365
2003	12,735,789,053	8,857,713,029	2,890,076,081	24,483,578,163
2007	15,210,746,603	11,337,687,846	3,586,409,189	30,134.843,638
2010	18,016,628,180	13,744,722,675	4,243,039,156	36,004,390,011
2018	28,475,658,883	23,632,761,923	6,423,783,827	58,532,204,633
2020	32,197,941,494	26,969,080,868	7,320,178,671	66,487,201,033

The increase in IOU distribution asset value from 2007, the year after the highest recorded peak year of 2006, to 2020 is $36.35 billion.[85] The annualized distribution cost factor

[81] Ibid, p. 35.

[82] 2018 SDG&E FERC Form 1, p. 216, line 58.

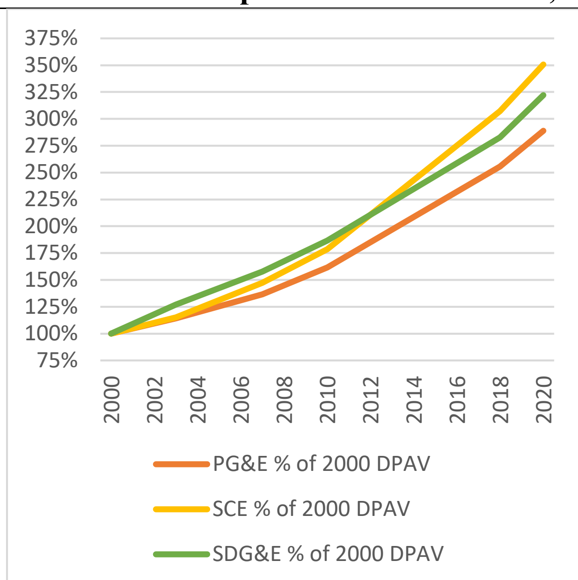
[83] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), Table 5, p. 35. SDG&E Wildfire Prevention Capital Expenditures, 2018 = $265.9 million. (Attachment 11)

[84] 2000, 2003, 2007, 2010, 2018, and 2020 PG&E, SCE, and SDG&E FERC Form 1s, p. 206.

[85] $66,487,201,033 - $30,134,843,638 = $36,352,357,395

for PG&E is 0.0979.[86] Using the PG&E annualized cost factor as representative, the annualized IOU distribution charges to ratepayers have risen by approximately $3.6 billion per year since 2007. This is approximately seven times higher than the $500 million per year NEM solar cost of service cost shift identified by E3 and Verdant in the Lookback Study. This trend is shown graphically in Figure 2.

Figure 2. IOU distribution plant asset value trend, 2000 – 2020



There was no vetting of the need or cost of the grid hardening projects proposed by SDG&E when it received approval in 2016 from the CPUC to carry-out wholesale replacement of wooden poles with steel poles and underground selected backcountry distribution circuits,[87] a $680 million capital project.[88] The CPUC's Division of Ratepayer Advocates, in its November

[86] E3, *2021 Distributed Energy Resources Avoided Cost Calculator Documentation* (June 22, 2021), Table 26. PG&E Distribution Annual MC Factor, p. 64.

[87] D.16-05-038, *Decision Granting (SDG&E) Permit to Construct the Cleveland National Forest Power Line Replacement Projects* (May 26, 2016), pp. 4-5.

[88] 2016 SDG&E SEC Form 10-K Annual Report, filed February 27, 2017, pdf. p. 364. "Cleveland National Forest (CNF) Transmission Projects, estimated cost = $680 million. Estimated completion: in phases through 2020." (Attachment 27)

2012 protest of the application, noted that SDG&E had not identified what problems it was attempting to solve with the proposed project.[89]

The CNF project was authorized by the CPUC as a permit to construct, because the voltage of the affected lines was less than 200 kV.[90] The issues of project need and economic cost were excluded from the scope of the proceeding.[91] The CPUC concluded, despite excluding examination of project need or cost, that "The safety, reliability, economic and environmental benefits of the proposed project present overriding considerations that merit its approval."[92]

SDG&E's approach to wildfire mitigation is now the wildfire mitigation template for California IOUs. PG&E, SCE, and SDG&E collectively spent $4.4 billion on wildfire mitigation in 2019.[93] The CPUC forecasts that California's three IOUs will spend $38.9 billion on wildfire

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[89] A.12-09-010, *Protest by the Division of Ratepayer Advocates of the San Diego Gas and Electric Company's Application for a Permit to Construct the Cleveland National Forest Power Line Replacement Projects* (Nov. 26, 2012), p. 6. "First, the Application does not specifically and factually state the nature of the electric transmission or distribution reliability problems that necessitate the CNF Projects. Second, it does not identify the particular component of the CAISO Tariffs, FERC Standards of Conduct, and/or NERC Reliability Standards that call for the CNF Projects as a result of these problems." (Attachment 28)

[90] D.16-05-038, Decision Granting Permit to Construct the Cleveland National Forest Power Line Replacement Projects (May 26, 2016), p. 12.

[91] Ibid, p. 12. "POC (Protect Our Communities Foundation) argues that the Commission nevertheless has a duty to consider project need and cost pursuant to Sections 451 and 1005.5(a). This argument amounts to an improper collateral attack on the many Commission decisions approving the exemption of projects with operating voltages at or below 200 kV from such review."

[92] Ibid, Conclusion of Law No. 3, p. 37.

[93] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), p. 60. "The last full year of wildfire mitigation spending data available during the preparation of this paper was for calendar year 2019. In comparing planned 2019 to actual 2019 spending, each IOU recorded significantly higher costs than estimated. PG&E planned to spend $2.5 billion and recorded $3 billion (19 percent higher). SCE planned to spend $671 million and recorded $1.6 billion (132 percent higher). SDG&E planned to spend $219.9 million and recorded $306.7 million (40

mitigation-related capital projects in the 2021-2030 period.[94] The wildfire mitigation value of this massive expenditure has not been demonstrated.[95] However, the shareholder value will be substantial.[96]

2. Accurately Quantifying Distribution Avoided Costs Eliminates the Cost Shift.

The CPUC forecasts that IOU residential rates will rise 35 percent (SCE) to 47 percent (SDG&E) from 2020 to 2030.[97] The CPUC also forecasts that residential rate growth above the rate of inflation in 2030 will be entirely due to wildfire mitigation capital expenditures in PG&E and SCE service territories, and substantially due to wildfire mitigation capital expenditures in SDG&E service territory.[98] There is no mention in the Joint IOUs', Cal Advocates', or TURN's opening testimony of cost benefit of NEM solar and storage as the lower-cost alternative to major proposed IOU wildfire mitigation T&D costs in the coming decade. Saturation deployment of customer-sited solar and storage in extreme High Fire Threat Districts (HFTDs)

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percent higher). These figures suggest actual spending may be higher than forecast in future years."

[94] Ibid, p. 60. "Baseline total incremental revenue requirement resulting from wildfire costs between 2021 and 2030 - PG&E: $20.2 billion; SCE: $14.8 billion; SDG&E: $ 3.9 billion."

[95] PCF, R.18-10-007, *The Protect Our Communities Foundation Comments on the 2020 Wildfire Mitigation Plans Pursuant to Resolution WSD-001* (Apr. 7, 2020), p. 35. (Attachment 29)

[96] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), p. 39. "The rate of return (ROR) on capital additions allows utility shareholders to earn profits for shareholders' benefit. Utilities have an incentive to seek FERC approval for the highest possible ROR. The more capital additions that go into operation, the more profit the IOUs can attain." (Attachment 11)

[97] Ibid, p. 8. "The paper's 10-year baseline forecast shows steady growth in customer rates (nominal $/kWh) between 2020 and 2030 for the three IOUs: PG&E: $0.240 to $0.329, or about an annual average increase of 3.7 percent; SCE: $0.217 to $0.293, or about an annual average increase of 3.5 percent; SDG&E: $0.302 to $0.443, or about an annual average increase of 4.7 percent."

[98] Ibid, Figures ES-1, ES-2, and ES-3, pp. 4-5.

has the potential to save IOU customers a substantial portion of the nearly $40 billion the CPUC forecasts will be spent by the IOUs on hardening the existing T&D system in extreme HFTDs in the 2020-2030 period.[99]

Assuming only half of the proposed $40 billion is avoided by saturation deployment of NEM solar and batteries in the extreme HFTDs, the annual avoided T&D hardening costs would be on the order of $2 billion per year.[100] This is more than three times greater than the residential NEM cost-shift of $618.6 million per year identified in the NEM 2.0 Lookback Study. Addressing wildfire mitigation with NEM solar + batteries would result in a substantial cost-shift from NEM residential customers to non-NEM residential customers.

The CPUC, in its decision approving the IOU's 2020 Wildfire Mitigation Plans (WMPs), observed that the internal risk assessment by the IOUs of their grid hardening program proposals is a "black box" with insufficient description of the supporting information and rationale for the grid hardening programs.[101] One party to the WMP proceeding described the IOU's calculated risk reduction for each wildfire mitigation measure as a ". . . *complete shot-in-the-dark – an unsupported number with little accuracy and much precision - and it does not appear to serve the purpose of ensure (sic) the most risk reduction per dollar spent or even focus on HFTDs*

[99] See footnote 98.

[100] Assume annualized PG&E transmission cost factor of 0.1046 (footnote 55) applied to $20 billion in T&D fire hardening capital investment. Therefore, annualized avoided T&D costs attributable to NEM solar + battery = 0.1046 × $20 billion = $2.09 billion/yr.

[101] D.19-05-036, Guidance Decision on 2019 Wildfire Mitigation Plans Submitted Pursuant to Senate Bill 901 (May 30, 2019), p. 29, footnote 42.

(high fire threat districts)."[102] The IOUs have what amounts to a blank check to pursue grid hardening projects, whether or not these projects result in any real reduction in fire hazard.

The continued reliance by the IOUs on public safety power shutoffs (PSPS) is a testament to the ineffectiveness of the IOU grid hardening strategies to assure reliable power under high fire threat conditions.[103] Customer-sited solar and storage is an alternative solution that would allow the IOUs to initiate PSPS events as needed without interrupting customer power supply and without huge capital investment in grid hardening projects.

The IOUs have shown little interest in this solution. The SDG&E 2019 WMP Decision required SDG&E to consider "renewables potentially coupled with storage" for backup generation,[104] an alternative solution to grid hardening – at much less cost – to reduce fire risk. However, SDG&E failed to comply.[105]

In contrast, The Commission allocated over $513 million of its 2020 to 2024 incentive budget, nearly two-thirds of the $814 million total budget, to equity resiliency customers.[106] "Equity resiliency" in this context means lower- and middle-income (LMI) customers living in HFTDs. The Commission, with this allocation of SGIP funds, recognized the resiliency value of

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[102] CPUC R.18-10-007, *Protect Our Communities Foundation Comments on 2020 Wildfire Mitigation Plans Pursuant to Resolution WSD-001* (Apr. 7, 2020), p. 35. (Attachment 29)

[103] Los Angeles Times, *Another summer of California power outages poses threat to Newsom as he faces recall* (May 24, 2021): https://www.latimes.com/california/story/2021-05-24/california-summer-blackouts-threaten-newsom-political-power. "So-called public safety power shut-offs have become common practice in California to prevent disaster as climate change drives record-setting wildfire seasons." (Attachment 30)

[104] Ibid, p. 32 and p. 35.

[105] Ibid, p. 35.

[106] D.20-01-021, Self-Generation Incentive Program Revisions Pursuant to Senate Bill 700 and Other Program Changes (Jan. 16, 2020), Table 4 - 2020 to 2024 Adopted Allocations and Total Incentives Budgets, p. 27.

NEM storage and the importance of assuring this NEM storage is available to low-income and vulnerable customers subject to power shutoffs.[107]

Events like the August 2020 rolling blackouts – in additional to power shutoff resiliency – have underscored the added resiliency value of augmenting NEM solar systems with battery storage. More than 50 percent of new NEM solar projects installed by some solar companies now include battery storage.[108] Aggregation of RPS-eligible NEM solar + storage projects, to maximize the value of these dispatchable battery storage systems, is also now occurring at the state level.[109] The NEM 3.0 tariff should be crafted to assure the sustainable growth of NEM solar + battery storage, to reflect the Commission's acknowledgement of the value of NEM battery storage in other Commission proceedings.

There are a manageable number of IOU customers in extreme (Tier 3) HFTDs. In the case of SDG&E, it has only 31,181 customer meters,[110] out of 1.4 million, in Tier 3 HFTDs. To put the number of SDG&E customers in Tier 3 HTFDs in perspective, approximately 30,000

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[107] Ibid, p. 10. "Energy storage offers customers the resiliency benefits of delivering electricity during PSPS (public safety power shutoff) events. SGIP equity resiliency and equity budget incentives allow low-income and vulnerable customers and disadvantaged communities the opportunity to access benefits that would otherwise be unavailable to them due to the relatively high cost of the installed technology."

[108] Greentech Media, *Sunrun Deploys Record Solar Capacity in Q4 as Battery Interest Increases* (Feb. 27, 2020). "More than half of Q4 solar sales in the Bay Area included battery storage, CEO Lynn Jurich said in an interview Thursday." See: https://www.greentechmedia.com/articles/read/sunrun-q4-earnings-battery-resilience. (Attachment 31)

[109] E-mail communication, between B. Powers, Powers Engineering and A. Singh, CPUC, regarding clarification on relative importance of 60% RPS by 2030 and MMT GHG reduction target (June 23, 2021). (Attachment 32)

[110] CPUC R.18-10-007, *Protect Our Communities Foundation Comments on 2020 Wildfire Mitigation Plans Pursuant to Resolution WSD-001* (Apr. 7, 2020), p. 38.

NEM solar projects are completed in SDG&E service territory every year.[111] The utility has nearly $2 billion since 2007 on wildfire mitigation in its HFTDs, and plans to spend nearly $4 billion more in 2021-2030. Much of the proposed $4 billion wildfire mitigation expenditures could be avoided by having all customers in the Tier 3 HFTD add solar and battery storage, and authorizing the IOUs to conduct power shutoffs at their discretion.

This same approach is equally applicable to PG&E and SCE customers located in Tier 3 HFTDs. PG&E indicates it has 169,162 customers in Tier 3 HFTDs.[112] SCE indicates it has 453,714 customers in HFTDs. Saturation deployment of NEM solar and batteries at these customer sites would eliminate the need to fire harden the existing T&D systems in these Tier 3 HFTDs.

C. E3 Has Already Demonstrated, Under Contract to the Commission, that Distributed Solar Is A Lower-Cost Alternative to Transmission-Dependent Utility-Scale Renewables

E3 has provided technical analyses under contract to the Commission supporting the position that distributed solar generation is comparable in cost to remote, new transmission dependent utility-scale solar. The CPUC formed a working group in 2009, known as the Renewable Distributed Energy Collaborative (Re-DEC), to evaluate the technical and cost

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[111] California Distributed Generation Statistics, Stats & Charts, accessed June 21, 2021: https://www.californiadgstats.ca.gov/charts/.

[112] PG&E, 2020 Wildfire Mitigation Plan Section 3 Baseline Ignition Probability and Wildfire Risk Exposure, pp. 3-17 to 3-19: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/2020-Wildfire-Safety-Plan. PG&E has a population of 29,274 living in HFTD tier 3 urban areas, 130,048 in HFTD tier 3 rural areas, and 9,840 living in HFTD tier 3 highly rural areas.

viability of meeting RPS targets with IOU-owned distributed solar located on commercial and industrial buildings, along with smaller (< 20 MW) ground-mounted arrays.[113]

E3 along with Black & Veatch (B&V), under contract to the CPUC in 2009, evaluated an IOU-owned warehouse rooftop solar alternative (High DG Case) to the 33% RPS Reference Case that required substantial new transmission to access remote wind and solar resources. E3 and B&V indicated that, at an installed DG solar capital cost of \$3.70 per watt_{DC} and unit energy cost of \$0.169/kWh (in 2009), the cost of the High DG Case was similar to that of the 33% Reference Case.[114] The bar chart that accompanies the E3 and B&V statement indicates the High DG Case, assuming a DG solar cost of \$3.70 per watt_{DC}, is slightly lower-cost than the RPS Reference Case.[115]

The cost-competitiveness of the High DG Case was accurate in 2009. SCE filed an application to build 250 MW of IOU-owned solar on industrial warehouse rooftops in March 2008 at an installed cost of \$3.50 per watt_{DC},[116] lower than the \$3.70 per watt_{DC} cost evaluated

[113] This was at a time of controversy over the construction of new transmission lines to enable development of remote utility-scale solar and wind projects. NEM solar was not eligible at the time to meet RPS requirements. For these reasons Re-DEC was focused on IOU- and third party-owned distributed solar projects interconnected directly to the distribution grid.

[114] E3 and B&V, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, Re-DEC Working Group Meeting (Dec. 9, 2009), p. 41. (Attachment 33)

[115] Ibid, p. 41.

[116] A.08-03-015, Application of Southern California Edison Company (U 338-E) for Authority to Implement and Recover in Rates the Cost of its Proposed Solar Photovoltaic (PV) Program (Mar. 27, 2008), p. 13. (Attachment 34)

by E3 and B&V. The CPUC ultimately approved a larger 500 MW SCE warehouse rooftop solar project in June 2009, stating:[117]

> Unlike other generation resources, these (large-scale rooftop solar) projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts.

The effect of the High DG alternative examined by E3 was to dramatically reduce the need for new transmission to meet RPS targets, relative to the 33% RPS Reference Case, as shown in Figure 3. E3 and B&V referenced this author's testimony to bolster their position on the cost viability of the distributed solar alternative to renewables dependent on new transmission.[118] It is the avoided cost of new transmission to meet renewable energy targets that drives the ability of the High DG Case to provide the same level of renewable power at the same or less cost than the new transmission-dependent alternative.[119]

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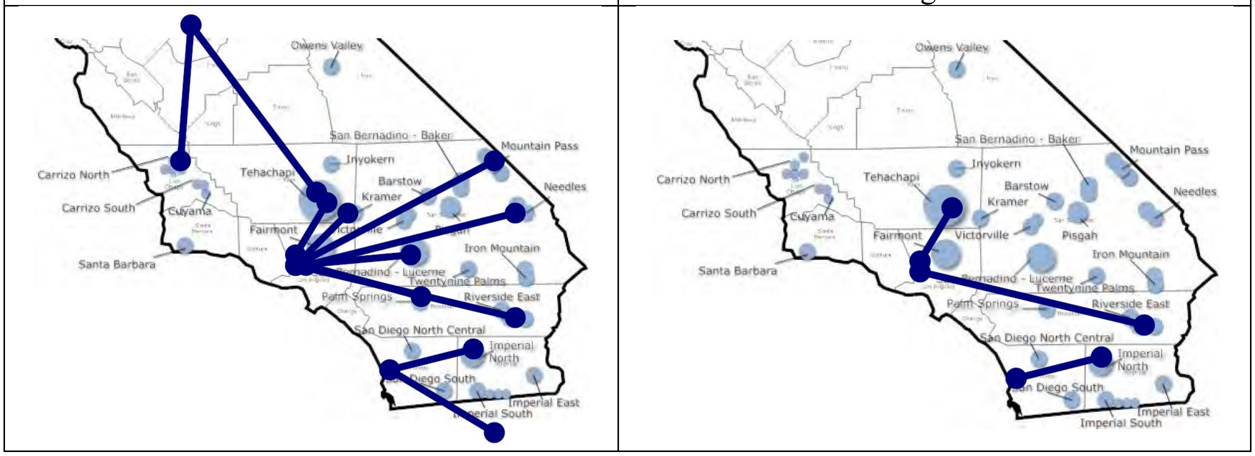
[117] CPUC press release, *CPUC Approves Edison Solar Roof Program* (June 18, 2009), available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/NEWS_RELEASE/102580.PDF. (Attachment 35)

[118] E3 and B&V (Dec. 9, 2009), p. 11. "If it is conservatively assumed that only 10,000 MW of new high voltage transmission will be built by 2020 to realize the RETI net short target of 68,000 GWh, the estimated cost of this transmission will be in the range of $20 billion in 2008 dollars based on SDG&E's projections for the Sunrise Powerlink. How much thin-film PV located at IOU substations or at the point-of-use on commercial buildings or parking lots could the IOUs purchase for this same $20 billion? ... This equals an installed thin-film PV capacity of 14,000 to 18,000 MW for a $20 billion investment." - Bill Powers, PE, testimony in SDG&E's Sunrise Powerlink CPCN case. (Attachment 33)

[119] Re-DEC assumed that IOU customers would be responsible for paying the cost of the IOU-owned in-front-of-the-meter distributed solar. NEM solar is paid for by the customer and not rate-based across all utility bundled customers as IOU-owned distributed solar would be.

Figure 3. New Transmission Required for Reference Base Case and High DG Case[120]

33% RPS Reference Case	High DG Case



D. Displacement of RPS Transmission in SDG&E Service Territory Would Add $1,050/yr in Value to Residential NEM Systems in SDG&E Territory

The Commission's February 2021 report, *Utility Costs and Affordability of the Grid of the Future*, identified SDG&E's 500 kV Sunrise Powerlink (SPL) transmission line as one of the three largest CAISO-approved transmission lines to come online in the last decade.[121] The SPL application was denied by the assigned administrative law judge (ALJ) in October 2008. The ALJ observed, at the end of a two-year proceeding, that the local generation alternative was superior to SPL for cost and reliability reasons.[122] The ALJ determined there was no near-term

[120] E3 and B&V (Dec. 9, 2009), p. 10 and p. 39. Note that the three new transmission lines shown in the High DG Case had already been authorized by the CPUC when the High DG Case was evaluated by E3 and B&V in late 2009. These transmission lines are: 1) SCE's Tehachapi Renewable Transmission Project: https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11; 2) SCE's Devers-Palo Verde 2: https://www.sce.com/about-us/reliability/upgrading-transmission/dpv2; and 3) SDG&E's Sunrise Powerlink: https://www.kpbs.org/documents/2010/may/05/approved-route-sunrise-powerlink/. p. 42: "We were not able to eliminate all transmission lines – assumed lines already approved go forward." (Attachment 33)

[121] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), Table 10, p. 38. (Attachment 11)

[122] A.06-08-010, *(Proposed) Decision Denying a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (Oct. 31, 2008), p. 4. "The record

reliability justification for SPL, and no regulatory framework (at the time) to mandate the line be dedicated to supplying renewable power.

The transmission line was ultimately approved in December 2008 via an alternate decision proposed by former Commission President Peevey, with the assigned commissioner to the SPL proceeding voting against approval of the transmission line.[123] SDG&E committed to interconnecting 1,000 MW of renewable power to SPL.[124] As of 2020, eight years after SPL came online in 2012, there was approximately 1,000 MW of solar and 265 MW of wind power connected to SPL.[125] The annualized cost of the $1.883 billion SPL, over 40 years, is $254 million per year.[126]

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shows, on balance, that all of the transmission proposals likely would provide additional reliability to SDG&E's service area. However, SDG&E's service area will not experience a reliability need or "shortfall" until 2014, and the shortfall may be met more economically and more reliably with generation-based alternatives."

[123] D.08-12-058, Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project (Dec. 18, 2008), pdf pp. 305-311, Dissent of Commissioner Dian M. Grueneich.

[124] Sempra press release, *SDG&E's Sunrise Powerlink Reaches 1,000 Megawatt Renewable Energy Goal* (Dec. 18, 2014), available at https://www.sempra.com/newsroom/press-releases/sdges-sunrise-powerlink-reaches-1000-megawatt-renewable-energy-goal. (Attachment 36)

[125] *SDG&E Final 2019 RPS Procurement Plan* (Jan. 29, 2020), Appendix 1 p. 15 & p. 18, available at https://www.sdge.com/sites/default/files/regulatory/2019_Final%20RPS%20Plan%20Public%20Version.pdf, 999 MW solar; + 265 MW Ocotillo Wind: https://patternenergy.com/learn/portfolio/ocotillo-wind. (Attachment 37)

[126] D.08-12-058, Finding of Fact 42, p. 289 (capital cost = $1.883 billion). Ratio of final $1.883 billion capital cost to original $1.265 billion capital cost multiplied by original annualized cost in A.06-08-010, plus annual O&M: [($1.883 billion/$1.265 billion) x $164 million/yr] + $10 million/yr O&M = $244 million/yr + $10 million/yr O&M = $254 million/yr.

The avoided transmission value of residential NEM solar, compared to the amortized capital cost of SPL to deliver the same amount of renewable energy, is approximately $1,050 per 6 kW_{AC} residential NEM system as shown in Table 6.

Table 6. Calculation avoided SPL transmission expenditure value of NEM solar[127]

Element	Calculation	Value
Capital cost of Sunrise Powerlink, 2008	--	$1.883 billion
Annualized cost of Sunrise Powerlink	40-year amortization of capital cost, plus $10 million/yr O&M expense	$254 million/yr
Actual renewables capacity connected to Sunrise Powerlink	999 MW solar, 265 MW wind	1,264 MW
Required number of residential NEM solar projects at 6 kW/each to achieve equivalent peak output	1,264,000 kW_{AC} ÷ 6 kW_{AC}/project	211,000 projects
Total NEM projects needed to account for lower NEM solar annual energy production compared to utility-scale solar[128]	0.27 (utility-scale capacity factor) ÷ 0.22 (NEM solar capacity factor) = 1.23	260,000 projects
Total NEM projects needed, adjusted for avoided T&D losses[129]	-7.24 percent	241,000 projects
Annual value of avoided SDG&E transmission per residential NEM project[130]	$254 million/yr ÷ 241,000 projects	$1,054/yr/project

[127] Supporting data is provided in Attachment 38.

[128] ICSREE 2020, *Capacity factors of solar photovolltaic energy facilities in California, annual mean and variability*, 2020. Table 1, p. 2 (2018 CF data for Imperial Valley solar facilities). See: https://www.e3s-conferences.org/articles/e3sconf/pdf/2020/41/e3sconf_icsree2020_02004.pdf; NREL, PVWatts Calculator, Los Angeles, 0.22 alternating current capacity factor with 15 percent assumed dc-ac system losses: https://pvwatts.nrel.gov/. (Attachment 39)

[129] See 2020 Avoided Cost Calculator.

[130] The estimated avoided RPS transmission cost of $1,500/yr/(NEM) system stated at p. 5 of PCF opening testimony did not include the 265 MW of wind capacity connected to SPL, an adjustment for different solar capacity factors for desert solar and urban load center NEM, or

At the time of the approval of SPL, GHG reduction was driven exclusively by RPS, and NEM solar did not count toward meeting RPS targets. NEM solar is just as effective at achieving GHG reduction targets established in SB 100 as remote, utility-scale solar,[131] and aggregated NEM projects are now RPS-eligible.

E. Displacement of RPS Transmission in SCE Service Territory Would Add Over $500/yr in Value to Residential NEM Systems in SCE Territory

The Commission's February 2021 report, *Utility Costs and Affordability of the Grid of the Future*, also identified SCE's 4,500 kV Tehachapi Renewable Transmission Project (TRTP) as one of the three largest CAISO-approved transmission lines to come online in the last decade.[132] The cost benefit of the displacing equivalent TRTP transmission capacity with NEM solar is over $500 per year per 6 kW_{AC} residential NEM system, as shown in Table 7.

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account for T&D losses associated with utility-scale remote solar, All of these adjustments are included in this revised avoided RPS transmission cost for SPL.

[131] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), p. 76. "In the 2019-2020 IRP process, the CPUC initially developed a 2030 (GHG) emissions target of 46 MMT. After receiving feedback from stakeholders, the CPUC required California's load-serving entities to submit two portfolios: one corresponding to a 46 MMT target and one corresponding to a stricter 38 MMT target." (Attachment 11)

[132] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), Table 10, p. 38. (Attachment 11)

Table 7. Calculation of avoided TRTP transmission expenditure value of NEM solar[133]

Element	Calculation	Value
Capital cost of TRTP	--	$3.07 billion
Annualized cost of TRTP	40-year amortization of capital cost, plus $10 million/yr O&M expense	$407 million/yr
Actual renewables capacity connected to TRTP	--	4,019 MW
Required number of residential NEM solar projects at 6 kW/each to achieve equivalent peak output	4,019,000 kW_{AC} ÷ 6 kW_{AC}/project	670,000 projects
Total NEM projects needed to account for lower NEM solar annual energy production compared to utility-scale solar[134]	0.27 (utility-scale capacity factor) ÷ 0.22 (NEM solar capacity factor) = 1.23	824,000 projects
Total NEM projects needed, adjusted for avoided T&D losses[135]	-7.24 percent	764,000 projects
Annual value of avoided SCE transmission per residential NEM project	$407 million/yr ÷ 764,000 projects	$533/yr/project

F. The Transmission Cost Avoided by NEM Solar Is As Much As Twice the Cost of the Purported Cost Shift

The cost benefit of NEM solar to avoid investment in new reliability transmission projects and RPS transmission projects is greater in value than: 1) the full cost of service cost-shift identified in the NEM 2.0 Lookback Study for residential NEM solar, and 2) cost-shift

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[133] Supporting calculations are provided in Attachment 40**.**

[134] ICSREE 2020, *Capacity factors of solar photovoltaic energy facilities in California, annual mean and variability*, 2020. Table 1, p. 2 (2018 CF data for Imperial Valley solar facilities). See: https://www.e3s-conferences.org/articles/e3sconf/pdf/2020/41/e3sconf_icsree2020_02004.pdf; NREL, PVWatts Calculator, Los Angeles, 0.22 alternating current capacity factor with 15 percent assumed dc-ac system losses: https://pvwatts.nrel.gov/. (Attachment 39)

[135] See 2020 Avoided Cost Calculator.

alleged in the Haas Report. Both avoided transmission cost benefits are shown in Table 8. The cancelled and avoided transmission costs enabled by NEM solar are on the order of two times greater than the residential NEM cost shift alleged in the Haas Report.

Table 8. Comparison of avoided new transmission value to alleged NEM solar cost-shift

Utility	Annual value of avoided load growth/economic transmission avoided per 6 kW_{AC} residential NEM project, $/yr	RPS transmission cost avoided per 6 kW_{AC} residential NEM project, $/yr	Total transmission costs avoided per 6 kW_{AC} residential NEM project, $/yr	Cost-shift per customer alleged by Haas Report corrected for $120/yr fixed charge paid by NEM customers,[136] $/yr
PG&E	625	794 (SPL + TRTP)/2	1,419	780
SCE[137]	625 (PG&E default)	533 (TRTP)	1,158	580
SDG&E	625 (PG&E default)	1,054	1,679	730

The sustained addition of NEM solar in the 2018-2020 time period, when 3,600 MW of NEM solar was added in California IOU service territories,[138] is suppressing the need for new

[136] Haas Report, p. 40. The estimates in Section 5 suggest that in 2019, the cost recovery gap is $4.3 billion for PG&E, $3.0 billion for SCE, and $1.1 billion for SDG&E. . . According to FERC data, there are 4.8 million residential PG&E accounts, 4.3 million in SCE, and 1.3 million in SDG&E. This means that, on average, PG&E needs to recover almost $900 per household per year; SCE needs to recover around $700 per household per year; and SDG&E needs to recover around $850 per year. IOU NEM customers pay $10/month, $120/yr, in fixed charges. $120/yr has been subtracted from the Haas Report's values to reflect the fact that NEM customers are already paying some of these costs in the form of a fixed monthly charge.

[137] Assumes same avoided cost range as PG&E and SDG&E.

[138] California Distributed Generation Statistics, Stats & Charts, accessed June 21, 2021: https://www.californiadgstats.ca.gov/. IOU NEM solar, December 31, 2017 = 5,620 MW; December 31, 2020 = 9,220 MW. NEM solar increase, 2018-2020 = 3,600 MW.

transmission additions that would otherwise be justified by load growth or congestion. This phenomenon is described in CAISO's 2020-2021 Transmission Plan in the following manner:[139]

> Load forecast growth continues to remain relatively flat, resulting in part from continued statewide emphasis on energy efficiency and behind-the-meter generation . . . Consistent with past studies, this transmission planning cycle did not reveal the need for major transmission expansion to achieve the 60 percent RPS goal set out in SB 100 for 2030.

The CAISO's 2020-2021 Transmission Plan statement is reasonable and expected for transmission expansion based on peak load growth, congestion, or reliability.

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?

The following sections of this testimony respond to Issue 5 identified in the Scoping Memo. They respond to the proposals of the Joint IOUs, Cal Advocates, and TURN, and specifically assert that the Commission should not adopt the regressive fixed charges proposed by those parties that will harm lower-income customers.

III. Regressive Fixed Charges at Core of Joint IOU, Cal Advocates, and TURN NEM 3.0 Tariff Proposals Disproportionately Hurt LMI Customers or Require Shifting Costs to Other Customers or Entities

The Haas Report, "Designing Electricity Rates for An Equitable Energy Transition," is cited in the opening testimony of the Joint IOUs, Cal Advocates, and TURN, and relied upon by Cal Advocates for its estimates of the current cost-shift purportedly caused by NEM

[139] CAISO, 2020-2021 Transmission Plan (Mar. 24, 2021) ("2021 TPP"), pp. 1-2, available at http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf. (Attachment 42)

customers.[140, 141] The Haas Report advocates for large fixed costs on NEM solar customers to address the alleged cost shift. However, the paper also recognizes that fixed monthly charges that are the same for all residential customers are also highly regressive, in that they take a much larger share of household income or expenditures from lower-income households than from wealthy customers.[142]

The Haas Report's solution to this equity dilemma is to impose fixed charges that vary with household income to retain the "efficiency" of an undifferentiated fixed charge. The Report proposes to use an extreme form of increasing-block pricing (IBP) to make the fixed charge more equitable. The imposition of steeply rising fixed charges that vary with household income is very similar to a five-tier rate structure that the Hass Report's lead author, Professor Borenstein, previously attacked as inequitable to high electricity usage customers.[143] Specifically, he argued that ". . . this extreme form of IBP violates one of the basic tenets of utility price setting: cost causation. Prices should reflect the cost of serving a customer."[144]

The treatment of extreme forms of IBP by Prof. Borenstein is contradictory. In the first instance, lower usage, lower income customers are being unjustifiably protected by the five-tier IBP, according to Borenstein. In the second instance, Borenstein advocates for an IBP with even

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[140] Cal Advocates Opening Testimony, p. 2-22.

[141] Joint IOUs Opening Testimony, p. 52, p. 83; Cal Advocates Opening Testimony, p. 2-21, p. 3-8; TURN Opening Testimony, p. 39.

[142] Haas Report, February 2021, p. 33.

[143] A comparison of PG&E's five-tier rate structure, and Prof. Borenstein's proposed five-tier fixed charge rate structure to address the NEM cost shift, is provided in Attachment 9.

[144] S. Borenstein, *Rationalizing California's Residential Electricity Rates* (Sept. 29, 2014): https://energyathaas.wordpress.com/2014/09/29/rationalizing-californias-residential-electricity-rates/. (Attachment 42)

more pronounced steps to mitigate the impact of regressive fixed charges on lower-income customers. In essence, if the end is tier-flattening, an extreme IBP is bad. If the end is allocating otherwise regressive fixed charges, an extreme IBP is good. This contradictory, "end justifies the means" approach to the IBP by Borenstein casts doubt on the utility of his review of the NEM cost-shift.

The proposed Joint IOUs, Cal Advocates, and TURN NEM 3.0 proposals suffer from the same weakness that Professor Borenstein attempts to address through IBP based on customer income level.[145] The high fixed charges in their proposals function as regressive charges on LMI customers. To address this weakness, cost causation is abandoned and artificial economic band-aids are recommended or applied[146,147] that require some entity other than the IOUs to cover a portion of the cost impact of the regressive charges on LMI customers.

IV. Joint IOUs, Cal Advocates, and TURN Propose NEM 3.0 Tariffs That Would Make NEM Solar Less Viable for All Customers

The Joint IOUs, Cal Advocates, and TURN propose to address NEM equity issues by making NEM solar less economically attractive to all customers. For example, the IOUs estimate that their reform tariff would increase the payback period for NEM customers from 3-4 years under NEM 2.0 to 15-19 years.[148] More than 150,000 NEM customers are low income.[149] Equity

[145] Haas Report, FIG 9a-c Example Income-Based Fixed Charge Schedules for 2019, p. 41.

[146] Joint IOUs Opening Testimony, p. 29. "Where possible, reforms to the NEM program should explore other ways (besides subsidies paid for by non-participating customers) to provide financial incentives for Californians' adoption of rooftop solar."

[147] TURN Opening Testimony, pp. 51-54.

[148] Joint IOUs Opening Testimony, p. 105.

[149] SCE, 2020-2022 Wildfire Mitigation Plan: Appendix B, Table 13, pp. 24-25: https://www.sce.com/sites/default/files/AEM/Wildfire%20Mitigation%20Plan/SCE%202020%20WMP%20Tables%201-31%20Revision%2002.pdf. SCE has a population of 323,745 living in

can be fully achieved under the existing NEM 2.0 tariff by mandating that the IOUs offer a tariffed on-bill financing program tied to the customer meter to assure that renters and lower income customers have equal access to solar and battery storage.[150]

This type of financing is already offered in California. BayREN is administering a OBF "tied to the meter" financing program for water efficiency measures in the Bay Area.[151] OBF tied to the meter financing is also available to Hawaii IOU residential customers.[152] "Tied to the meter" means the meter is billed, not the customer behind the meter. This equity financing tool is under evaluation in the Commission's R.20-08-022 clean energy financing proceeding.[153] The answer to NEM equity is employing the appropriate financing mechanism, not making NEM solar less financially viable for IOU customers.

Currently the IOUs offer very limited OBF programs, restricted to commercial customer energy efficiency upgrades. These OBF programs do not cover residential customers, renters, solar, or battery storage. The Commission authorized the utilities to modify or expand their OBF programs through a simple advice letter process in 2019.[154] This same 2019 decision recognized

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HFTD tier 3 urban areas, 92,195 living in HFTD tier 3 rural areas, and 37,774 living in HFTD tier 3 highly rural areas.

[150] CPUC R.20-08-022, *The Protect Our Communities Foundation's Opening Comments to Assigned Commissioner's Ruling Seeking Party Feedback on Track 1 Issues Related to California Hub for Energy Efficiency Financing Programs* (Apr. 16, 2021), p. 2. (Attachment 43)

[151] R.20-08-022, Clean Energy Finance Workshop - Day 2, January 28, 2021, pp. 34-46. (Attachment 44)

[152] Ibid, pp. 52-58.

[153] CPUC R.20-08-022, *The Protect Our Communities Foundation's Opening Comments to Assigned Commissioner's Ruling Seeking Party Feedback on Track 1 Issues Related to California Hub for Energy Efficiency Financing Programs* (Apr. 16, 2021). (Attachment 43)

[154] D.19-03-001, *Decision Granting Petition for Modification of Decision 09-09-047 Concerning On-Bill Financing* (Mar. 14, 2019), Attachment A, p. 3 ("II. New Ordering Paragraph: Decision

the need to consider opening IOU OBF programs to private capital in order to expand the programs.[155] The Commission and the IOUs have been aware of the desirability of including residential customers in the utility OBF programs for over a decade,[156] though to date no residential OBF programs have been implemented by the IOUs.

V. CALSSA and SEIA/Vote Solar Both Present Acceptable Revisions to the NEM 2.0 to Incentivize Adding Battery Storage

The current NEM 2.0 tariff does not shift costs from NEM customers, either non-residential or residential, to non-NEM customers. PCF also recognizes the importance of adding battery storage to NEM solar systems and revising the NEM 2.0 tariff to incentivize the inclusion of battery storage.

PCF supports methods for increasing the attachment rate of storage to NEM systems. Both the California Solar and Storage Association ("CalSSA") and the Solar Energy Industries Association ("SEIA")/Vote Solar ("VS") recommend in their proposals threshold levels or time-based step downs of the compensation rate for energy exported to the grid.[157] Both of these

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09-09-047 is further modified to add Ordering Paragraph 61, as follows: 61. PG&E, SCE, SDG&E, and SoCalGas may each file a Tier 2 advice letter for Commission review and approval of proposed program changes . . .").

[155] Ibid, p. 17 (Finding of Fact 10: "NRDC has raised valid issues in its filed comments regarding how to enable the investor-owned utilities to manage their on-bill financing loan programs so that private capital is deployed, thereby enabling more loans and more energy-saving projects.").

[156] D.09-09-047, *Decision Approving 2010 to 2012 Energy Efficiency Portfolios and Budgets* (Sept. 24, 2009), p. 274 ("The (EE) Strategic Plan adopted in D.08-09-040 identified the need for financing solutions in both the residential and commercial sectors," and p. 278, "SDG&E reports it is investigating partnering with a financial institution to more directly offer residential retrofit financing, allowing the lending partner to absorb any risk and transaction costs. . .").

[157] California Solar & Storage Association's Proposal For a Successor to the Current Net Energy Metering Tariff ("CalSSA Proposal") (Mar. 15, 2021), p. 3; Proposal of The Solar Energy Industries Association and Vote Solar For a Net Energy Metering Successor General Market Tariff ("SEIA/VS Proposal") NEM 3.0 Proposal (March 15, 2021), p. 4.

proposals incentivize NEM 3.0 customers to install battery storage with their NEM systems. Either of these proposals would provide the Commission with workable solutions for incentivizing increasing levels of storage.

PCF concurs that the Commission should gradually increase the incentive for installing NEM storage. Customer-based storage will continue to reduce the peak load and net peak load across the state, even as those peak loads shift further into the evening hours when solar alone no longer produces electricity. As PCF noted in its opening testimony, supply constraints are maintaining current battery storage prices for residential systems at artificially high levels, and that future battery pricing will decline substantially when a supply-demand balance is attained.[158] The tariff revisions proposed by SEIA/VS and CalSSA would appropriately phase-in storage incentives as supply constraints on storage ease over the next several years.

PCF also supports the SEIA/VS proposal to allow for "NEM customers to oversize their systems by up to 50%."[159] Oversizing incentivizes behind-the-meter electrification. SEIA/VS's proposal provides similar benefits to PCF's own "Proposal E" that recommended oversizing arrays paired with limited-time export rate benefits.[160] Other parties also proposed export incentives for oversizing of NEM systems to facilitate 100 percent clean electrification. The Sierra Club's proposal included a recommendation that oversizing be allowed to ensure the

[158] R.20-08-020, Prepared Testimony of Tyson Siegele on Behalf of The Protect Our Communities Foundation (June 18, 2021) pp. 11-12.

[159] R.20-08-020, Proposal of the Solar Energy Industries Association and Vote Solar for a Net Energy Metering Successor General Market Tariff (Mar. 15, 2021), p. 24.

[160] R.20-08-020, The Protect Our Communities Foundation Net Energy Metering 3.0 Tariff Proposals A-E, (Mar. 15, 2021), pp. 14-18.

future addition of electric vehicle and electric heating loads is met with onsite solar.[161] The Commission leverage NEM 3.0 to address the goal of beneficial electrification to minimize carbon emissions.

There is no currently no cost shift from non-residential NEM customers to non-NEM customers, as shown in the Lookback Study cost-of-service analysis,[162] even without considering the cost benefit of non-residential NEM in eliminating proposed new T&D. The IOU non-residential NEM tariffs should be retained largely in their current form, with one exception: the non-residential NEM tariffs should be augmented with terms to incentivize battery deployments, as described in the CALSSA and SEIA/Vote Solar proposals.

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[161] R.20-08-020, Sierra Club Successor Tariff Proposal (Mar. 15, 2021) p. 32.

[162] Lookback Study, Figure 1-2, p. 10.