MEMORANDUM

December 23, 2021

TO: Interested Parties and Stakeholders to California Rulemaking (R.) 20-08-020, Net Energy Metering Revisit
FROM: EQ Research LLC
SUBJECT: How the Proposed Decision in R.20-08-020 Compares to Current Policy and Recent Net Energy Metering Decisions in Other States

Executive Summary

On December 13, 2021, the California Public Utilities Commission (CPUC) released a Proposed Decision in California Rulemaking (R.) 20-08-020, proposing to close the current net energy metering (NEM) "2.0" tariff to new customers and establish a new Net Billing tariff that would apply to new solar customers going forward, and existing customers at the 15-year anniversary date or whenever their property is sold. The Net Billing tariff would erode the economics of solar in several key ways, including:

- Adding a new **solar-specific monthly fixed charge** of $8/kW/month based on system size (kW-AC) that would apply to residential customers in PG&E, SCE, and SDG&E service areas. A Market Transition Credit (initially $1.62/kW/month for PG&E customers, $3.59/kW/month for SCE customers, and no credit for SDG&E customers, with a higher credit for Low Income customers) would apply for a period of 10 years.

- Requiring new solar customers to take service under **highly differentiated time-of-use rates.** For SCE and SDG&E customers, these rates include **additional monthly customer charges**.

- Significantly reducing the **export compensation rate** from the retail rate (less non-bypassable charges) to a rate based on hourly Avoided Cost Calculator values averaged across days in a month, differentiated by weekdays and weekends and by climate zones. Exports would also be measured on a so-called "**instantaneous netting**" basis.

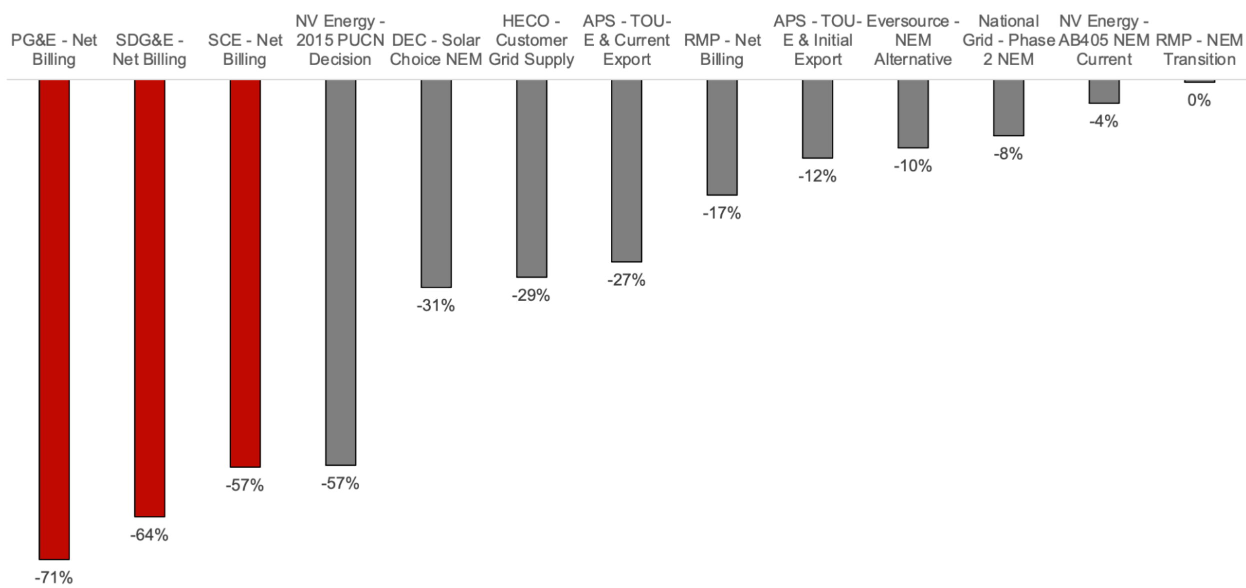
Previously, EQ Research published a memo on November 16, 2021 that analyzed several of the solar-specific fixed charge proposals in the NEM rulemaking. This memo updates that analysis based on the Proposed Decision. It also analyzes the impacts of the proposed export rate reduction in the Proposed Decision, comparing it both to California's current NEM 2.0 program, as well as recent NEM successor tariff decisions across the country.

This memo is organized as follows. First, it analyzes the residential fixed charges imposed by the Proposed Decision, as well as the impact of the Market Transition Credit. Next, the Export Compensation Rates and instantaneous netting proposals from the Proposed Decision are discussed. Third, the memo provides the results of an analysis EQ Research conducted on how the monthly customer charges, solar capacity charges, export rate reductions, instantaneous netting changes, and rate design would affect customer value in California's three large investor-owned utility (IOU) territories, and compares those effects to the impacts of successor tariff designs in other jurisdictions.

Key findings in this memo include:

- **The Proposed Decision would impose a 57-71% overall reduction in the residential solar savings rate, *inclusive of 100% of the Market Transition Credit*, which would be the largest reduction ever imposed by a top 20 solar state (Figure ES-1)**. This reduction is larger than the impact of a 2015 decision by the Public Utilities Commission of Nevada that implemented instantaneous netting, high fixed charges, and failed to provide adequate protection for legacy net metering customers, which produced dramatic reductions in residential solar installations until it was repealed and replaced.

Figure ES-1. Reduction in Residential Solar Savings Rate from Key State NEM Decisions Compared to the CPUC Proposed Decision



- The Proposed Decision would impose the largest solar capacity charges on residential rooftop solar customers in the nation. The $8/kW/month solar capacity charge, translating to $48/month for a typical 6 kW system, would be nearly 50% larger than the next-highest solar capacity charge in the United States.

- The Proposed Decision would increase the total fixed charges imposed on residential solar customers relative to the current monthly minimum bill by 510% for SDG&E customers, 472% for SCE customers, and 380% for PG&E customers.

- The only two utilities that assess total fixed charges on residential solar customers comparable to those in the Proposed Decision are Alabama Power in Alabama ($5.41/kW solar capacity charge, plus a $14.50 customer charge) and Black Hills

Power in Wyoming ($8.25/kW demand charge, plus a $15.50 customer charge), neither of which have meaningful levels of distributed solar in their service areas.

- A Market Transition Credit would be available to eligible new solar customers of PG&E and SCE, but only for a period of 10 years. For a new system installed by a PG&E or SCE customer in 2022, the Market Transition Credit would only offset 10% and 18%, respectively, of the total fixed charges imposed by the Proposed Decision over a 20-year period.

- The Proposed Decision would immediately reduce solar customer export credit rates under Net Billing relative to NEM 2.0 by an average of 73-84% for residential customers. The reduced export credit rate would apply to low-income homes, multi-family apartment buildings, schools, and other customers.

- The Proposed Decision would retroactively reduce the legacy period for NEM 1.0 and NEM 2.0 customers, meaning an estimated 35,425 early adopters of rooftop solar who installed solar by 2008 when systems cost roughly $12 per watt (nearly four times what solar costs today), would be transitioned to the Net Billing tariff by 2023 and be required to pay an average of $689 per year in new fixed charges, assuming a 6 kW system.[1]

[1] https://www.californiadgstats.ca.gov/charts/

I. New Fixed Charges and the Market Transition Credit

There are several types of monthly fixed charges, including customer charges paid by all customers in a rate class ($/month), capacity charges based on solar system size ($/kW/month of DC system capacity), and monthly maximum load demand charges ($/kW based on a customer's peak demand).[2] These types of fixed charges can affect customer savings in two ways. First, they directly increase monthly customer bills in a way that they cannot avoid, either via self-generation or other means. Second, when rates are designed to meet a specific revenue requirement, an increase in fixed charges produces a corresponding decrease in other rate components.

Monthly minimum bills are a separate type of charge that are sometimes lumped in with fixed charges, but in practice a minimum bill is often more "avoidable" than a traditional fixed charge. Unlike a fixed charge designed to meet a revenue requirement, a minimum bill does not tend to reduce the volumetric rate components. A monthly minimum bill is only triggered when a customer would otherwise avoid paying a minimum amount (e.g., $10 each month), thus for many customers it may not be applied during most months, if ever. However, if a monthly minimum bill is set sufficiently high it may effectively amount to a monthly fixed charge for a solar customer.

The Proposed Decision would adopt both higher monthly customer charges and the largest solar capacity charge in the United States on residential Net Billing customers. First, it would require SCE and SDG&E customers to take service under rate schedules that feature fixed customer charges that are higher than the default residential customer minimum bill for both utilities:[3]

- For SCE customers, the customer charge would be $12.01 (compared to a minimum bill of only $10.52/month under Schedule TOU-D).
- For SDG&E customers, the customer charge would be $16.00 (compared to a minimum bill of only $10.49/month under Schedule DE-SES).

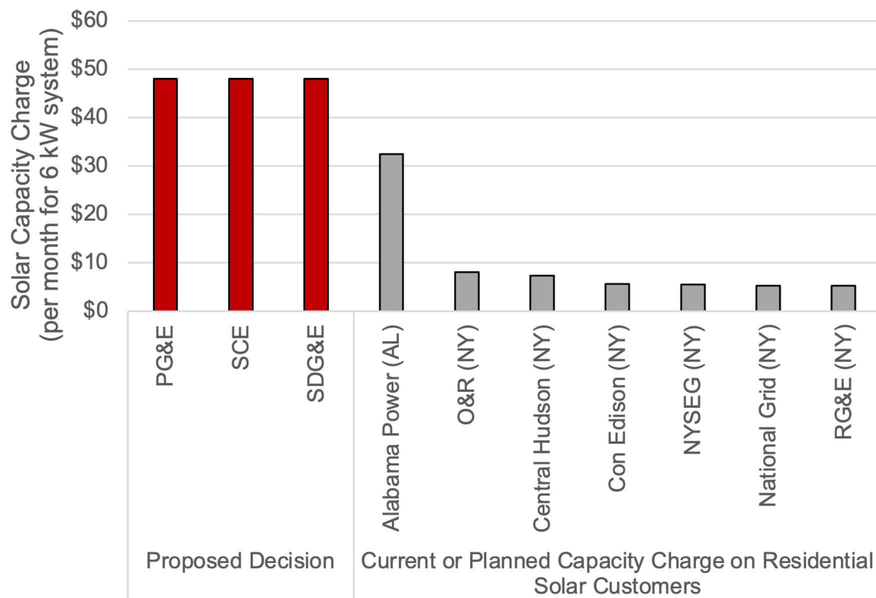
Second, and far more significantly, the Proposed Decision would create a new solar capacity charge called the Grid Participation Charge that would operate as an additional fixed monthly charge. For the first 10 years, the Grid Participation Charge would be $8/kW/month, meaning the owner of a typical 6-kW system[4] would have to pay their utility an additional $48/month, regardless of whether they also install energy storage. Customers with larger systems would pay a proportionately higher Grid Participation Charge (e.g., $80/month for a 10 kW system). After 10 years, the Grid Participation

[2] For residential customers charges based on monthly maximum demand ($/kW) are often considered to operate like a fixed charge because residential customers can typically exercise little or no control over their monthly maximum demand.
[3] In contrast to SCE's and SDG&E's rates, PG&E's Schedule EV2-A has the same minimum bill as Schedule E-6, the default residential rate.
[4] Unless otherwise noted, this memo uses 6 kW as the assumed average solar system size.

Charge would be updated.[5]

As shown in Figure 1, the Grid Participation Charge would be the largest solar capacity charge of any IOU and is 48% higher than the next-largest solar capacity charge ($5.41/kW, imposed by Alabama Power). The only two utilities that assess total fixed charges comparable to those in the Proposed Decision are Alabama Power in Alabama ($5.41/kW solar capacity charge, plus a $14.50 customer charge, totalling $46.96/month for a 6 kW system) and Black Hills Power in Wyoming ($8.25/kW demand charge, plus a $15.50 customer charge, totalling $65/month for a customer with a 6 kW peak demand), neither of which have meaningful levels of distributed solar in their service areas.

Figure 1. A Comparison of Residential Solar Capacity Charges under the Proposed Decision to Existing or Planned Solar Capacity Charges in Other Jurisdictions[6]



In a November 2021 memo analyzing utility charges on residential solar customers, EQ Research found that less than 2% of IOUs (3 out of 172) across the U.S. currently impose additional monthly fixed charges that are paid only by solar customers, with an additional six IOUs (all in New York) planning to add relatively modest fixed charges on residential solar customers in 2022. The memo noted that there have been at least 27 instances of IOUs *proposing* a solar-specific charge on residential customers since November 2012, but that nearly every IOU proposal to impose a solar-specific fee on residential customers over the past decade has been rejected, withdrawn by the utility, or subsequently overridden through legislative or judicial action.

[5] It is unclear from the Proposed Decision to what extent the Grid Participation Charge could change (e.g., increase or decrease) in the future. Therefore, the analysis in this memo assumes the $8/kW/month Grid Participation Charge continues indefinitely at that rate.

[6] The solar capacity charges for the IOUs in New York go into effect January 1, 2022. The O&R and RG&E values are estimates based on preliminary values provided earlier in the 2021, as final capacity charge values were not available at the time this memo was written. The values for the other IOUs reflect the Customer Benefit Contribution charge calculated by the utility in tariff filings made in December 2021.

Most recently, the Arizona Corporation Commission struck down Arizona Public Service's (APS) $0.93/kW ($6.51 per month for a typical system of 7 kW in APS's service territory) solar capacity charge in a November 2021 decision in the utility's rate case. The APS solar capacity charge was the only such charge imposed by an IOU located in the West. Figure 2 compares the since-removed APS solar capacity charge to the total additional fixed charges on California IOU customers under the Proposed Decision for both a 6 kW and a 10 kW solar system. **Residential solar customers in California would pay approximately 9 to 10 times more in extra monthly fixed charges under the Proposed Decision than the extra monthly fixed charges that were imposed on APS customers in Arizona prior to that charge being rescinded by regulators.** The average total fixed charges (i.e., the Grid Participation Charge plus the fixed customer charge) imposed in the Proposed Decision across the three IOUs is $689 per year for a 6 kW system and $1,073 per year for a 10 kW system.

Figure 2. Total Annual Fixed Charges on Residential Solar Customers under the Proposed Decision Compared to Arizona Example

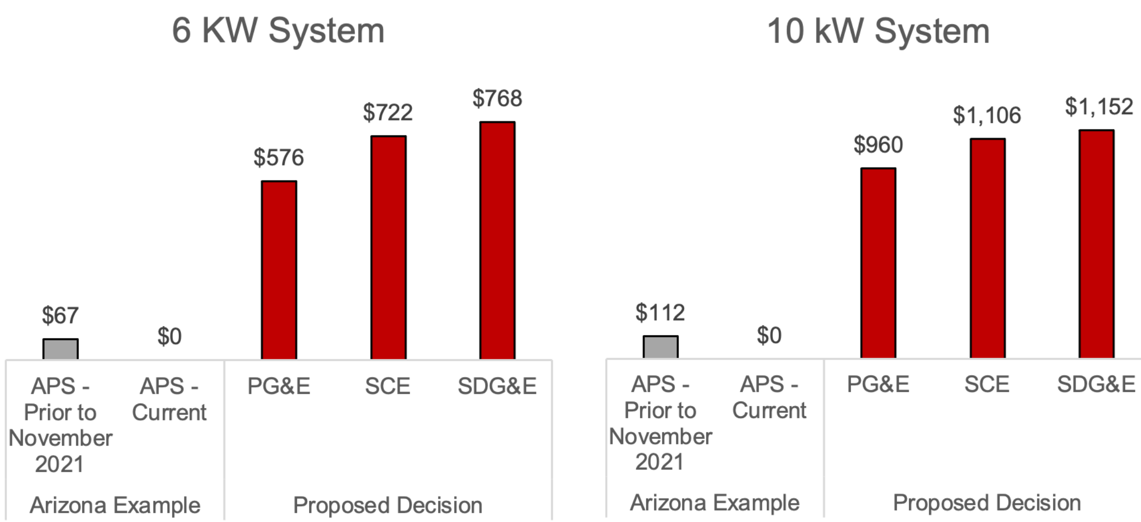
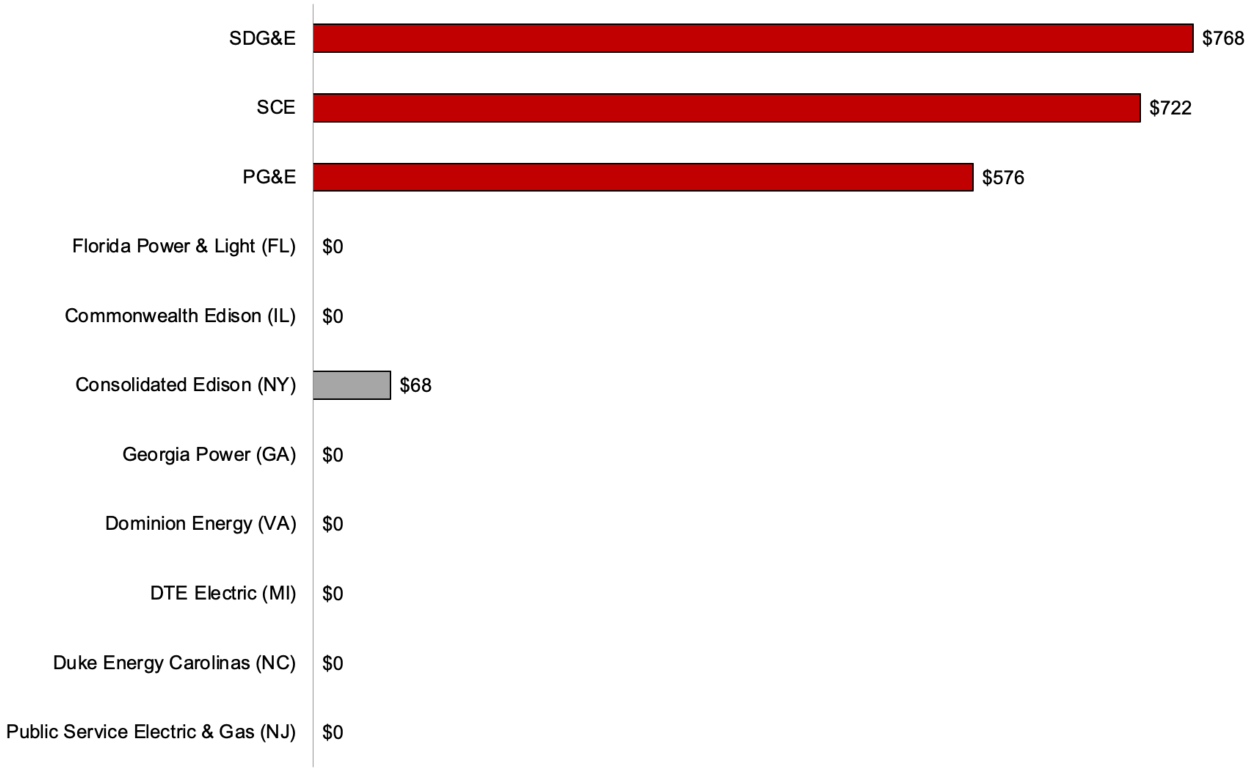


Figure 3 compares the additional fixed charges on residential solar customers in the Proposed Decision to those imposed by large IOUs, defined as those serving at least 2 million customers. The only large IOU outside of California to impose an additional fixed charge on residential solar customers is Con Edison in New York, which is imposing a solar capacity charge on net metering customers beginning in 2022.

Figure 3. Annual Additional Fixed Charges on Residential Solar Customers (6 kW System) Under the Proposed Decision Compared to Large IOUs[7]



Certain customers installing systems over the next four years would be eligible for a Market Transition Credit, which steps down for new customers each year, that for 10 years would partially offset the additional monthly fixed charges for customers of PG&E and SCE (but not for SDG&E customers), as shown in Figure 4. For SCE and PG&E customers installing a new solar system in 2022, the Market Transition Credit would only offset 36% and 20%, respectively, of the new fixed charges imposed by the Proposed Decision over the first 10 years, and only 18% and 10%, respectively, over a 20-year period as a result of the Market Transition Credit expiring after 10 years and assuming the current fixed charges continue to apply. For example, a PG&E customer installing a system in 2022 under the Net Billing tariff (i.e., eligible for 100% of the Market Transition Credit) would receive a total Market Transition Credit of $1,166 over 10 years.[8] However, the same customer would pay $11,520 in Grid Participation Charges over a 20-year period.[9] In other words, this aspect of the Proposed Decision would result in net additional fixed charges of $10,354 for a 2022 PG&E solar customer over a 20-year period, taking into consideration the Grid Participation Charge and the Market Transition Credit.

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[7] Large IOUs are those with more than 2 million customers as of December 2020 as reported on U.S. Energy Information Administration Form 861.
[8] 6 kW * $1.62/kW/month * 12 months * 10 years = $1,166.40.
[9] 6 kW * $8/kW/month * 12 months * 20 years = $11,520.

Figure 4. The Customer Charge, Grid Participation Charge, and Market Transition Credit for PG&E, SCE, and SDG&E Under the Proposed Decision

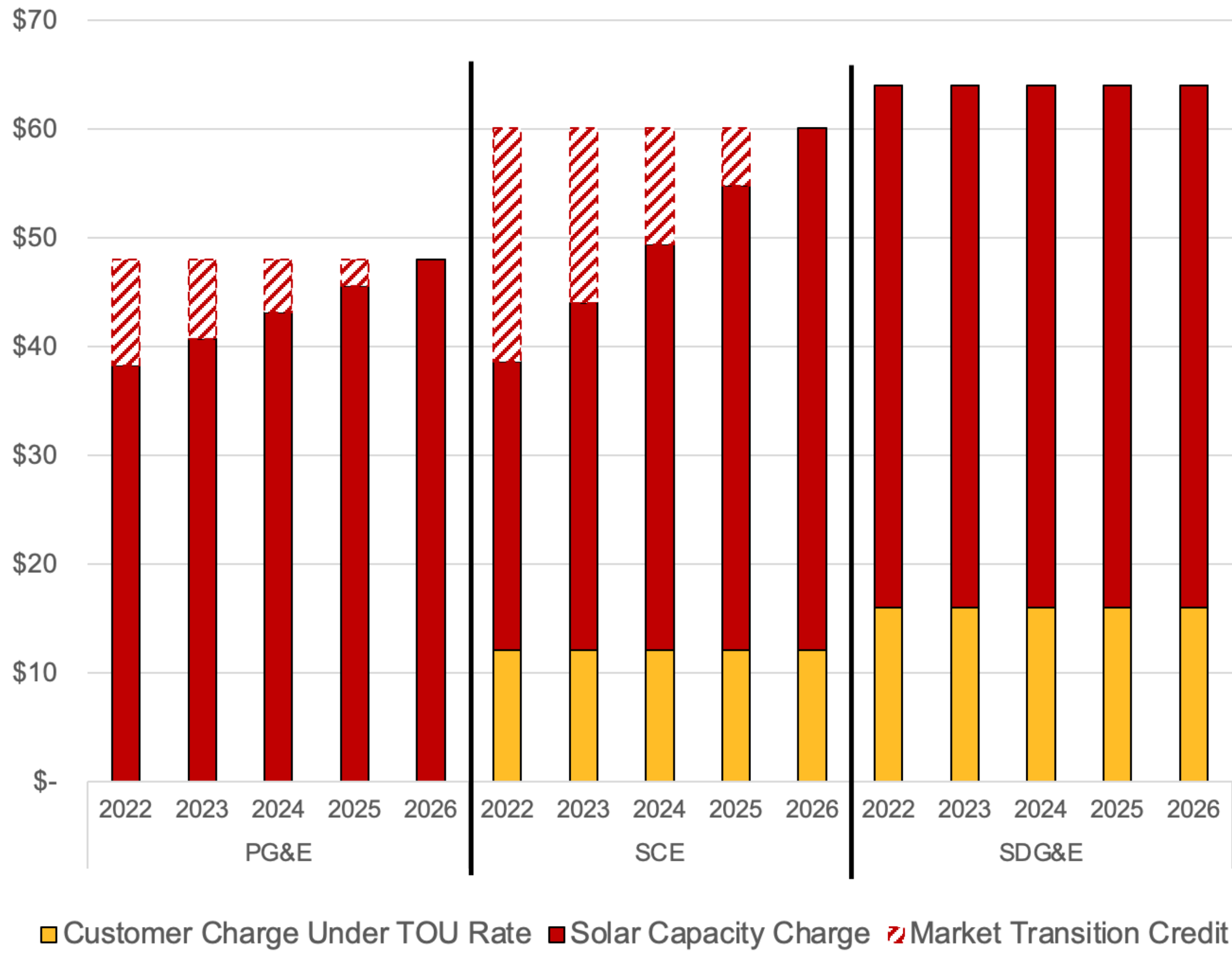
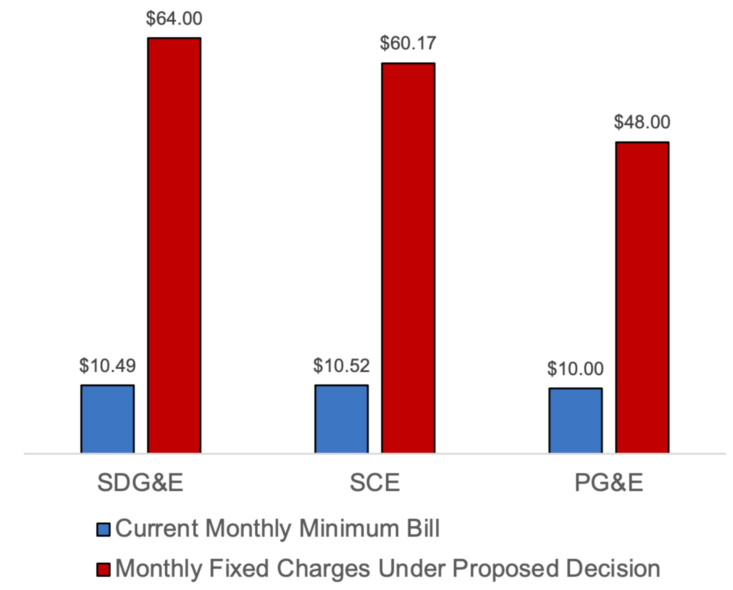


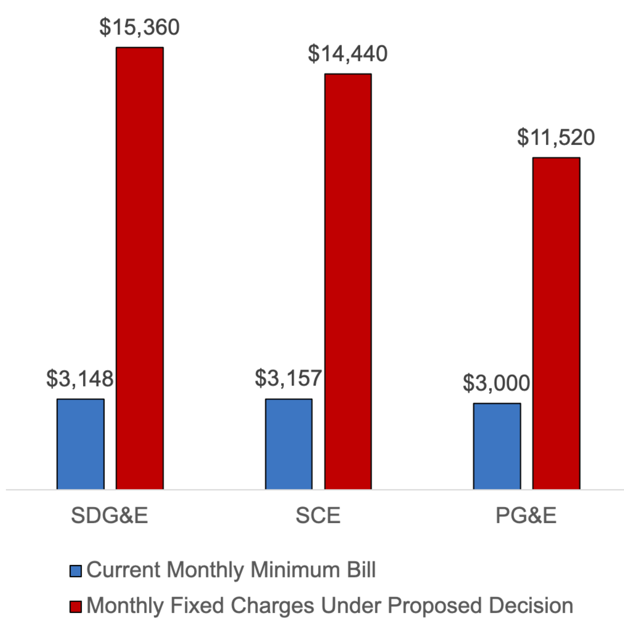
Figure 5 compares the current minimum bills that residential customers pay under NEM 2.0 to the total monthly fixed charges included in the Proposed Decision, inclusive of both the monthly customer charge under the new required rate schedule and the new Grid Participation Charge, and exclusive of the Market Transition Credit. If adopted, the Proposed Decision would dramatically increase the total fixed charges imposed on residential solar customers relative to the current monthly minimum bill, with increases of 510% for SDG&E customers, 472% for SCE customers, and 380% for PG&E customers.

Figure 5. Comparison of Total Monthly Fixed Charges on Residential Solar Customers under the Proposed Decision to Existing Monthly Minimum Bills



As shown in Figure 6, the impact of these monthly charges over the first 20 years of a rooftop solar system is dramatic. For example, a PG&E customer installing solar would go from paying up to $3,000 in minimum bill charges under the current residential rate to paying $11,520 in fixed charges under the Proposed Decision over the first 20 years of system ownership (assuming the fixed charges remain constant).

Figure 6. Comparison of 20-Year Costs of the Total Fixed Charges on Residential Solar Customers under the Proposed Decision to Existing Minimum Bills



II. Reductions to the Export Compensation Rates

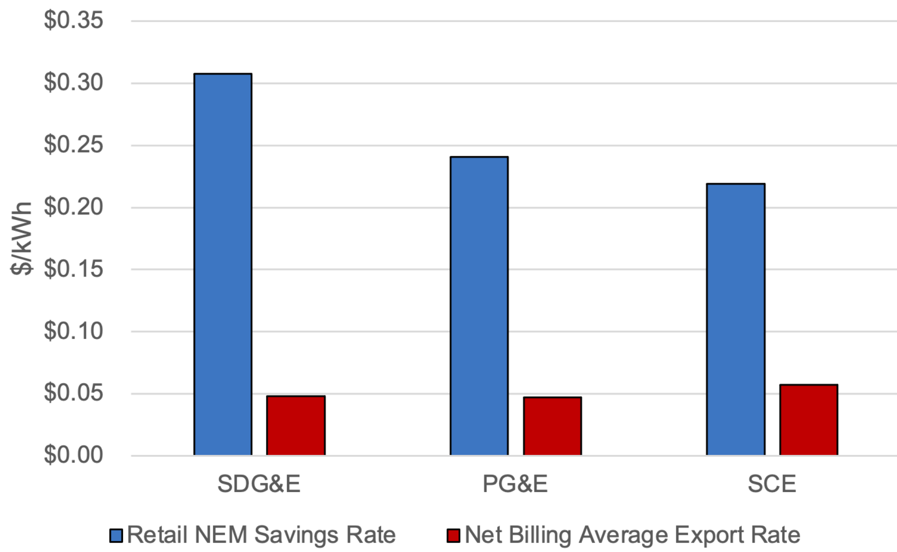
Under NEM 2.0, residential solar customers currently receive a full retail rate credit, specific to the time-of-use period, for exported generation. However, NEM 2.0 residential customers must pay non-bypassable charges on net imported generation, as measured on a 60-minute interval basis. For example, if during a month total hourly imports by a customer totaled 100 kWh and hourly exports totaled 200 kWh (a net monthly load of -100 kWh) the customer pays non-bypassable charges based on the 100 kWh of electricity that they pulled from the grid.

The Proposed Decision would adopt Export Compensation Rates for Net Billing customers based on hourly Avoided Cost Calculator values averaged across days in a month, differentiated by weekdays and weekends.[10] Adding further complexity, there will be separate export compensation rates for each of the 16 climate zones. The average Export Compensation Rate is roughly an 80% reduction to the existing compensation rates under NEM 2.0 (Figure 7). For the first five years after system interconnection, export compensation rates will be based on a five-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the customer's interconnection date. Following the five-year lock-in rate, export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1 of each year. Potential issues with these change include:

- Customers are not able to forecast what the Export Compensation Rates will be after 5 years, as the rate will change annually based on currently unknown updates to be made to the Avoided Cost Calculator, meaning customers will not be able to accurately estimate the financial viability of a solar investment.
- There is no "glide path" for the application of the substantially reduced Export Compensation Rates relative to the current retail-rate crediting under NEM 2.0.
- The new Export Compensation Rates will apply to all customers, including Low Income customers, as well as legacy net metering customers on NEM 1.0 and 2.0 tariffs after only 15 years, instead of the 20-year legacy period previously established by the CPUC, raising equity and fairness concerns.
- The Export Compensation Rates vary on an hourly and monthly basis by climate zone and are applied to exports on an instantaneous basis, which introduces significant complexity that most residential customers will have difficulty navigating.

[10] Proposed Decision, Ordering Paragraph 3(a).

Figure 7. Comparison of Compensation Rates Under NEM 2.0 and Net Billing



A reduction in the compensation rate for exports from the retail rate (or approximate retail rate) produces different results depending on how the export rate is applied. For tariff regimes that measure exports on a monthly basis by netting them against imports during the month, the effect of changes in the export rate is relatively modest for residential customers because a system designed to offset 100% of annual load will produce monthly exports during only some months, and those exports would typically not exceed 20% of total annual system production.[11]

Shorter netting periods or the absence of a netting period for exports (instantaneous export measurement), such as under the proposed Net Billing tariff, produce far more severe impacts on customer savings for a given reduction in the export rate. On an hourly basis during a typical year, at least 50% of production from a 100% load offset system is likely to be exported, and a 60% export percentage would not be unusual. Under hourly netting, the same 60% reduction in the export rate produces a 36% reduction in customer value from the system (60% * 60%). When exports are measured on an instantaneous basis, the export percentage is likely to be several percentage points higher, with correspondingly greater impacts on customer bill savings relative to hourly netting.

[11] The impact of the lower export rate in these circumstances is limited to a small percentage of total system production. For example, if monthly exports amount to 15% of total system annual production, a 60% reduction in the export rate only produces a customer savings reduction of 9% (i.e., 60% multiplied by 15%).

III. Combined Impacts of High Fixed Charges and a Low Export Compensation Rate and Comparison to Other Jurisdictions

In sum, how a solar customer is charged for electric service and how a solar customer is compensated for the electricity they export to the grid both have a meaningful impact on the overall value that an on-site solar system provides to that customer. This value can be illustrated as a customer's "savings rate," measured as the average amount a customer saves for each kWh that their solar system produces. Under net metering with kWh rollover from month to month, this savings amount is simply the volumetric retail rate, potentially differentiated by time-of-use pricing periods.

EQ Research developed a comparison of the impacts of net metering successor decisions in states with significant rooftop solar penetration based on net metering successor decisions in the top 20 states with the most installed net metered megawatts per capita based on Form EIA-861[12] and the U.S. Census Bureau[13] (see **Appendix A** for details). Of these 20 states, seven (excluding California) have adopted net metering successor tariff regimes (i.e., Arizona, Hawaii, New Hampshire, Nevada, New York, South Carolina, and Utah). For this analysis, a net metering successor decision was defined as a final decision or enacted legislation in which a new DG compensation policy was adopted that departed from a historic net metering regime in the form of charges placed on residential solar customers or changes to how these customers are compensated for electricity exported to the grid.[14]

Figures 8 and 9 summarize the results of this analysis, which is described further below. The solar savings rate would fall from an average of $0.24/kWh to $0.07/kWh for PG&E customers, $0.31/kWh to $0.11/kWh for SDG&E customers, and $0.22/kWh to $0.09/kWh for SCE customers (Figure 8). As a result, **the Proposed Decision would impose a 57-71% reduction in the residential solar savings rate (inclusive of 100% of the Market Transition Credit), which would be the largest reduction ever imposed by a state utility regulator in a top 20 solar state (Figure 9)**. **Notably, the Proposed Decision's impacts are more severe than the Public Utilities Commission of Nevada's (PUCN) controversial 2015 decision that resulted in a dramatic reduction in rooftop solar installations.** That decision was ultimately overturned by the legislature through the adoption of AB 405 in 2017, which reestablished net metering for residential customers with modestly declining export compensation rates for net excess generation at the end of the billing month.

[12] https://www.eia.gov/electricity/data/eia861/

[13] https://www.census.gov/library/visualizations/interactive/2020-population-and-housing-state-data.html

[14] Excluding California, the remaining states in the top 20 that have retained net metering without any significant changes are: Colorado, Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Jersey, New Mexico, Oregon, Rhode Island, and Vermont. Maine is not included in the successor list because its past successor regime was repealed and net metering was reinstated. Connecticut is not included as a successor state because the soon to be deployed residential solar tariff retains a traditional net metering option without a non-bypassable charge assessed until at least 2023. Vermont has not been listed as a successor state because the present net metering regime retains a retail net metering character despite certain differences between it and an older version of the net metering rule.

Figure 8. Impact of State NEM Decisions on Residential Solar Savings Rates

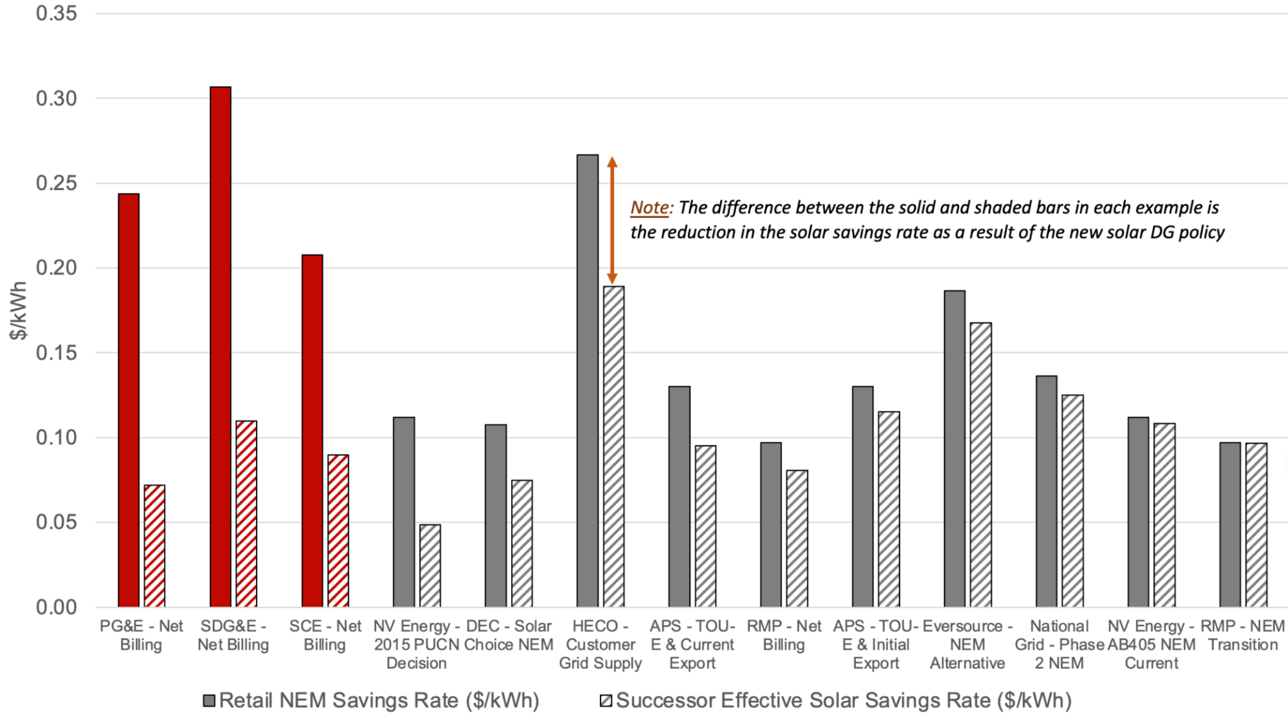
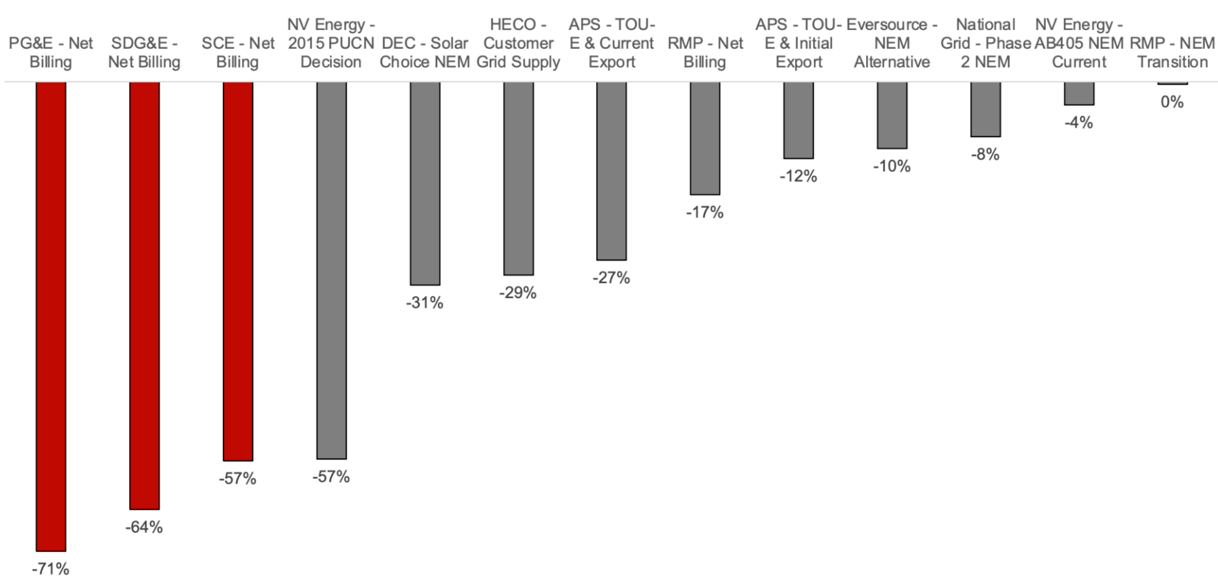


Figure 9. Reduction in Residential Solar Savings Rate from Key State NEM Decisions Compared to the CPUC Proposed Decision



The impacts of a net metering successor regime were calculated by analyzing the combination of the netting regime under which "exports" are determined by the rate applied to those exports, and any charges or rates that are specific to solar customers. Tables 1 and 2 illustrate impacts of both by showing comparisons between the average value of solar production to the customer under net metering (i.e., annual customer savings divided by solar production, effectively the volumetric retail rate) and:

- The rate applied as compensation for exports (Table 1).[15]
- The effective solar savings rate after consideration of specific rates or rate designs that apply to solar customers (e.g., mandatory time-of-use (TOU) rates and additional fixed charges) in addition to changes to the netting regime and/or export rate (Table 2).

Tables 1 and 2 both include comparable data for the Proposed Decision and are sorted according to the percentage change in value.

Table 1. NEM Successor Regime Reductions in Export Credit Rate

State	Utility	Scenario	Retail NEM Export Rate ($/kWh)	Successor Export Rate ($/kWh)[16]	% Reduction in Export Rate
California	SDG&E	CPUC Proposed Decision	$0.3067	$0.0481	-84.3%
California	PG&E	CPUC Proposed Decision	$0.2438	$0.0503	-79.3%
Nevada	Nevada Power Company	PUCN 2015 Decision - Final Step	$0.1121	$0.0265	-76.4%
California	SCE	CPUC Proposed Decision	$0.2078	$0.0570	-72.6%
Hawaii	HECO	Customer Grid Supply (CGS)	$0.2666	$0.1507	-43.5%
Utah	Rocky Mountain Power	Net Billing - Schedule 137	$0.0970	$0.0564	-41.8%
Arizona	Arizona Public Service	TOU-E - Current Export Rate	$0.1302	$0.0945	-27.4%
Utah	Rocky Mountain Power	DG Transition - Schedule 136	$0.0970	$0.0920	-5.1%
Arizona	Arizona Public Service	TOU-E - Initial Export Rate	$0.1302	$0.1290	-0.9%

[15] Table 1 is limited to states where the net metering successor regime features the elimination of netting periods (i.e., an export rate applied to all kWhs sent to the grid) because rates applied to monthly exports are not directly comparable to rates applied to monthly exports from the standpoint of impacts on customer savings.
[16] This evaluation understates the impact of instantaneous measurement of exports because it uses hourly solar and customer load profiles.

Table 2. NEM Successor Regimes Reductions in Residential Customer Solar Savings

State	Utility	Successor Netting Regime	Scenario	Retail NEM Savings Rate ($/kWh)	Successor Effective Solar Savings Rate ($/kWh)	% Reduction in Solar Savings Rate	$/kWh Reduction in Solar Savings Rate
California	PG&E	Instant	Proposed Decision: No Transition Credit*	$0.2438	$0.0668	-72.6%	-$0.1771
California	PG&E	Instant	Proposed Decision: Transition Credit*	$0.2438	$0.0719	-70.5%	-$0.1720
California	SDG&E	Instant	Proposed Decision	$0.3067	$0.1099	-64.2%	-$0.1968
California	SCE	Instant	Proposed Decision: No Transition Credit*	$0.2078	$0.0786	-62.2%	-$0.1291
California	SCE	Instant	Proposed Decision: Transition Credit*	$0.2078	$0.0896	-56.9%	-$0.1182
Nevada	Nevada Power Company	Instant	PUCN 2015 Decision - Final Step	$0.1121	$0.0486	-56.6%	-$0.0635
South Carolina	Duke Energy Carolinas	Monthly - TOU Time Bin	Solar Choice	$0.1077	$0.0749	-30.5%	-$0.0328
Hawaii	HECO	Instant	Customer Grid Supply (CGS)	$0.2666	$0.1892	-29.0%	-$0.0774
Arizona	Arizona Public Service	Instant	TOU-E - Current Export Rate	$0.1302	$0.0953	-26.8%	-$0.0349
Utah	Rocky Mountain Power	Instant	Net Billing - Schedule 137	$0.0970	$0.0806	-16.9%	-$0.0164
Arizona	Arizona Public Service	Instant	TOU-E - Initial Export Rate	$0.1302	$0.1153	-11.5%	-$0.0149
New Hampshire	Eversource	Monthly	Net Metering Alternative Tariff	$0.1864	$0.1677	-10.0%	-$0.0187
New York	National Grid	Indefinite Rollover	Phase 2 NEM	$0.1362	$0.1250	-8.2%	-$0.0111
Nevada	Nevada Power Company	Monthly	AB 405 NEM - Final Tranche	$0.1121	$0.1082	-3.5%	-$0.0039
Utah	Rocky Mountain Power	Instant	DG Transition - Schedule 136	$0.0970	$0.0966	-0.4%	-$0.0003

*The evaluation of the Net Billing tariff for PG&E and SCE includes two scenarios each, one which incorporates 100% of the Market Transition Credit and one that does not. The Market Transition Credit scenarios use the net of the Grid Participation Charge and the Market Transition Credit as a system capacity charge for 10 years and the GPC without the Market Transition Credit for an additional 10 years. Under this methodology over 20 years the net capacity charge is $7.19/kW for PG&E and $6.21/kW for SCE.

The data for both tables was developed using the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) to estimate first-year customer savings with solar under both the successor regime and the net metering regime that preceded it. The Retail NEM Savings Rate ($/kWh) is calculated as:

$$\frac{\textit{Annualized pre-solar bill under Standard Rate (\$) - Annualized post-solar bill with NEM (\$)}}{\textit{Annualized Solar Production (kWh)}}$$

The Successor Effective Solar Savings Rate ($/kWh) is calculated as:

$$\frac{\textit{Annualized pre-solar bill under Standard Rate (\$) - Annualized post-solar bill with Successor (\$)}}{\textit{Annualized Solar Production (kWh)}}$$

As shown above, the Successor Effective Solar Savings Rate ($/kWh) is calculated in reference to savings from what a customer's bill would be under the standard residential rate rather than in reference to the pre-solar bill under the successor. In this way, any bill increases or decreases that might be presented by the successor rate itself — such as higher fixed charges or total pre-solar bill changes caused by a TOU rate design — are accounted for with the "standard" rate reference in mind.

For simplicity, for each state the comparison was conducted for the investor-owned utility with the largest amount of residential solar that is subject to the successor regime. Although rates will differ from utility to utility, the overall magnitude of the impact of the successor in terms of a percentage reduction in customer savings (i.e., in the column labeled "% Reduction in Solar Savings Rate") should generally be similar from utility to utility within a common successor regime. See **Appendix B** for additional information on EQ Research's methodology for this analysis.

Excluding California, only seven of the top 20 solar states, as measured by net metered capacity per capita, have chosen to adopt a successor net metering tariff policy applicable to residential solar customers. See **Appendix C and D** for additional details about the legacy periods and the elements of various successor net metering policies that were adopted in other states.

The remaining 12 states continue to offer net metering in a way that is effectively consistent with how it has historically been implemented in the state. This is not to say that changes have not been considered in these states, whether due to specific legislative changes or at the initiative of regulators. For instance, Vermont adopted new net metering rules effective in 2017, and Connecticut is poised to implement new solar tariff options beginning in 2022. However, in both cases the state maintained retail net metering in character with modest changes, in the form of a revised retail rate calculation and adjustments for renewable energy credit (REC) conveyance and siting considerations in Vermont, and in the form of a buy-all, sell-all option (in addition to net metering) in Connecticut. Likewise, in South Carolina, while regulators approved the establishment of a successor "Solar Choice" net metering tariff with terms very distinct from historic net metering in the Duke Energy service territories, they largely rejected Dominion South Carolina's Solar Choice tariff proposal and instead retained retail net metering with a mandatory TOU rate requirement.

In a different category are states such as Maine and Massachusetts, where regulators adopted changes — a tranched buy-all, sell-all regime in Maine and a monthly minimum reliability charge in Massachusetts — but those changes were later invalidated by legislation. Finally, other states such as Colorado have conducted more loosely defined investigations of the value of behind-the-meter solar, but have not taken further steps, or issued specific policy findings in a contested case or rulemaking setting.

Conclusion

The CPUC's Proposed Decision would replace net metering with a new Net Billing tariff that features large fixed charges, highly differentiated time-of-use rates, instantaneous netting, and Export Compensation Rates substantially below the current retail rates and without a "glide path." These changes would apply to both new solar customers as well as retroactively to existing solar customers under NEM 1.0 and 2.0 after 15 years, despite these customers previously being guaranteed a 20-year legacy period.

Notably, the Proposed Decision would impose a Grid Participation Charge that would be the highest solar capacity charge in the nation, and would be nearly 50% higher than the second-largest solar capacity charge among investor-owned utilities. The only two utilities that assess total fixed charges comparable to those in the Proposed Decision are Alabama Power in Alabama ($5.41/kW solar capacity charge, plus a $14.50 customer charge) and Black Hills Power in Wyoming ($8.25/kW demand charge, plus a $15.50 customer charge), neither of which have meaningful levels of distributed solar in their service areas. The total fixed charges imposed on residential solar customers relative to the current monthly minimum bill would increase by 510% for SDG&E customers, 472% for SCE customers, and 380% for PG&E customers. The Market Transition Credit, which is only available to a subset of PG&E and SCE customers for a period of 10 years, does relatively little to offset the negative impact of these changes, providing a total credit that amounts to only 10% and 18%, respectively, of the new fixed charges on PG&E and SCE customers over the first 20 years of the life of a system.

Collectively, these changes would impose the most substantial reduction in the solar savings rate (57-71%) realized by residential customers investing in solar of any net metering decision analyzed by EQ Research in a top 20 solar state. This reduction is larger than the impact of a 2015 decision by the Public Utilities Commission of Nevada that implemented instantaneous netting, high fixed charges, and failed to provide protections for legacy net metering customers, which led to a dramatic reduction in residential solar installations until it was repealed and replaced.

Appendix A

Top 20 Solar States: Installed Net Metered Solar Per Capita

Rank	State	NEM MW (All Sectors)	Population	MW/Million People
1	HI	548	1,455,271	376
2	AZ	1,699	7,151,502	238
3	MA	1,627	7,029,917	231
4	CA	9,137	39,538,223	231
5	NJ	2,020	9,288,994	217
6	VT	126	643,077	196
7	RI	184	1,097,379	168
8	NV	498	3,104,614	160
9	CT	571	3,605,944	158
10	MD	846	6,177,224	137
11	DC	84	689,545	121
12	NM	223	2,117,522	106
13	UT	319	3,271,616	98
14	NY	1,789	20,201,249	89
15	DE	84	989,948	85
16	NH	113	1,377,529	82
17	CO	450	5,773,714	78
18	ME	72	1,362,359	53
19	SC	221	5,118,425	43
20	OR	168	4,237,256	40

Appendix B

Methodology Assumptions

The evaluation used the following methods, sources, and assumptions:

- For modeling solar production and customer load, the location was selected as a major city within the applicable utility service territory. Solar production was modeled using default SAM settings and hourly load profiles were imported from OpenEI using the Base profile for the applicable location. The use of hourly solar production and customer load profiles produces an effective hourly netting regime. As a consequence it will by nature understate the impact of tariff designs that measure exports on an instantaneous basis because exports measured on an instantaneous basis will always be higher than exports as measured on a net hourly basis.
- System size was adjusted to provide an approximate 100% annual load offset. Modifying this assumption would have a material impact on the results, for which the amount of exports to the grid are one primary factor.
- Retail rates were imported from OpenEI using internal SAM capabilities. Where possible the prevailing rates at the time of the net metering successor decision were used in the evaluation of both customer savings under net metering and customer savings under the successor regime. Where a suitable set of historic tariff rates could not be identified the current rates were used instead.
- Customer savings with solar under net metering was annualized according to the rules of the prevailing net metering policy (e.g., annual reset in March each year) or optimized in the case where rollover is indefinite. In some cases this required adjustments to SAM outputs because SAM reports pre-solar and post-solar customer savings on a calendar year basis.
- Rate elements that could not be modeled in SAM (e.g., charges based on system capacity in $/kW) were added manually to the SAM results as a deduction to annual customer savings.
- The evaluation of the Duke Energy Carolinas Solar Choice rate in South Carolina was conducted outside of SAM (using the same data sources) because the unique time-of-use netting regime and minimum bill design used for the rate could not be modeled directly in SAM.
- The evaluation of the California utilities net billing rate structures under the PD were conducted outside of SAM (using the same data sources) because data exports indicated errors in the calculations. It is not clear to us whether those errors arose from within the model or from incorrect selection of inputs.
- The California net billing analyses use the following key assumptions regarding customer location and rates.
    - All utilities were modeled on a calendar year Relevant Period basis.
    - SDG&E: DR-SES as the default NEM 2.0 rate. Load and solar profile from the vicinity of San Diego International Airport (Lindbergh Field as the load profile location).
    - PG&E: TOU-C (Region X) as the default NEM 2.0 rate. Load and solar

profile from San Jose.

- SCE: TOU-D-4-9 (Region 8) as the default NEM 2.0 rate. Load and solar profile from Santa Ana.

Appendix C

Legacy Rights under State NEM Policies

State	Transition Year to NEM Successor Tariff or NEM modifications	Legacy Period	Legacy Eligibility Deadline
AR	TBD; not before 2023	20 years from date of Phase 3 Order (June 1, 2020)	Applies to customers submitting a signed Standard Interconnection Agreement to the utility by December 31, 2022
AZ	2017, or in rate case order issued thereafter	NEM: 20 years from date of interconnection Successor: 10-year lock-in of export rate from date of application	Effective date of rate case decision establishing the applicable RCP rate (August 17, 2017 for APS)
CA	2017, or when utility reached 5.0% cap, for moving from "NEM 1.0" to "NEM 2.0"	20 years from interconnection year ***Proposed Decision would reduce to 15 years***	Interconnection before July 1, 2017, or date when utility cap reached, whichever comes first
CT	2022	20-year term will apply to both the Netting Tariff and Buy-All Tariff options	December 31, 2021
HI	2015	NEM: Indefinite (lifetime of system)	October 12, 2015
IA	Utilities may propose changes after July 1, 2027, or when the NEM cap is reached	20 years	Iowa Utilities Board Order adopting changes to compensation rate
IL	TBD	Indefinite (lifetime of system)	TBD
IN	July 2022 at the latest	Up to 15-30 years (expires July 1, 2047 for all NEM customers enrolled by December 31, 2017; expires July 1, 2032 for NEM customers enrolled after 2017 through July 1, 2022)	System operating before July 1, 2022 (or earlier for utilities reaching net metering cap) to lock-in NEM through July 2032. System operating before December 31, 2017 to lock-in NEM through July 2047.
KS	Post-July 2014 NEM customers can be subjected to additional charges or alternative rate designs	15 years (Pre-July 2014 customers have a Legacy period through 2029 against reduced rate for monthly excess and additional charges)	System operating prior to July 1, 2014
KY	2021 (LG&E, Kentucky Utilities, and Kentucky Power) TBD for Duke Energy Kentucky	NEM: 25 years NEM-2: 25-years for monthly netting and two-part rate design	Date of PSC Order approving changes in utility rate case to NEM or rate design
LA	2020	At least 15 years (expires December 31, 2034)	Interconnection application and installation completed by December

			31, 2019
MI	2019 (DTE) 2021 (Consumers Energy)	10 years	Based on final order date in utility's rate case establishing NEM successor tariff.
NH	2017	NEM: At least 23 years Modified NEM: Up to 23 years (expires December 31, 2040)	June 23, 2017
NY	2022	NEM: Indefinite (lifetime of system) Phase One NEM: 20 years	January 1, 2022
SC	2021	NEM: Up to 10 years (through 2025 or 2029 depending on installation date). Interim NEM Rider: Up to 8 years (Took effect June 1, 2021 and expires May 31, 2029 for all customers)	Interconnection application filed on or before May 31, 2021 for NEM and December 31, 2021 for Interim NEM Rider.
UT	2017	NEM: At least 18 years (expires in 2035) NEM Transition: Up to 15 years (expires 2032)	September 29, 2017

Appendix D

Comparison of Attributes of Modified Net Metering Policies in Selected States

State (Utility)	Mandatory TOU	Special Solar Rate	Incremental Fixed Charge	Minimum Bill*	Capacity Charge	Excess Generation Credit
AZ (APS)	Yes	No	No	No	No[17]	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)
AZ (TEP)	No	No	No	No	No	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)
CA NEM 2.0	Yes	No	No	No	No	Retail rate by TOU period, less non-bypassable charges.
CA **Net Billing Tariff**	**Yes** ***Restricted to specific TOU rates***	**No**	**Yes** ***Required TOU rates have higher fixed charges than other TOU options***	**No**	**Yes** ***$8 per kW per month***	**Instantaneous Netting with exports credited at ACC rate**
CT	No	No	No	No	No	Monetary export rate set at retail rate
HI	No	No	No	No	No	Monetary export rate for all exports
MA	No	No	No	TBD	No	Retail less public purpose charges

[17] A $0.93/kW capacity charge on customers that take non-demand TOU service was initially part of the successor design but was eliminated in 2021 after review of the reasonableness of the charge in a rate case.

NH	No	No	No	No	No	Retail less 75% of distribution rate and small non-bypassable charges
NY	No	No	No	No	$0.69 - $1.09/kW (public purpose charges)	Retail rate for residential, small commercial, and BTM
NV	No	No	No	No	No	For residential customers, retail rate during the month. Monthly excess credited based on a declining schedule based on installed capacity; currently, 75% of retail rate for monthly excess (the lowest of the four compensation tiers)
SC (DEC and DEP)	Yes	No	No	$30	$3.95 - $5.86/kW (only for systems 15 kW or larger)	Imports and exports netted within each TOD pricing period; net exports credited at avoided cost
TX (El Paso Electric)	No	No	No	$30 (Standard) ; $26.50 (TOU Rate)	No	Monthly credit at avoided cost
VT	No	No	No	No	No	Average retail + adders

*Denotes a minimum bill specific to solar or DG customers, not a minimum bill applied in an equivalent manner to all customers, as in California under the current NEM successor tariff or in Hawaii.