BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision D.16-01-044, and to Address Other Issues Related to Net Energy Metering	Rulemaking 20-08-020

PROPOSAL OF THE UTILITY REFORM NETWORK FOR A SUCCESSOR TO THE CURRENT NET ENERGY METERING TARIFF

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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PROPOSAL OF THE UTILITY REFORM NETWORK
FOR A SUCCESSOR
TO THE CURRENT NET ENERGY METERING TARIFF

Pursuant to January 28, 2021 Ruling of Administrative Law Judge Kelly Hymes, The Utility Reform Network (TURN) hereby submits a proposal for a successor to the current Net Energy Metering (NEM) tariff.[1] TURN submits that the information included in this filing is sufficient for other parties to fully analyze this tariff proposal and for the Commission to adopt all, or some, of its components as part of a final decision in this proceeding.

In a March 5, 2021 Ruling, ALJ Hymes indicated that parties should identify the individuals responsible for presenting each party's proposal at the March 23-24 workshop.[2] TURN's lead attorney, Matthew Freedman (matthew@turn.org), will present the tariff proposal. In addition, TURN requests time for its outside consultant, Michele Chait (michele@chaitllc.com), to present on the NEM tariff and cost model developed for this proceeding that is being made available to all parties and Commission staff. A description of the model inputs, logic and functionality is attached to this proposal and a fully functional Excel version is available for download and use by all parties.[3]

This filing includes all the information and explanation requested in the January 28, 2021 Ruling. Section II provides the required three-page summary of TURN's proposal. This summary include an overview of each element, comparison to the E3 White Paper, a short explanation as to how the proposal meets each relevant statutory criteria, and a

[1] ALJ Email Ruling Introducing White Paper, Noticing Workshop on White Paper, and Providing Instructions for Successor Proposals, January 28, 2021, Instruction #5.
[2] ALJ Email Ruling, March 5, 2021. ("When filing the proposals, parties shall indicate who will be responsible for presenting the proposal for the party sponsor(s) at the March 23-24 workshop. The name and email address of the presenter shall be contained within the first or second paragraph of the March 15, 2021 filing.")
[3] See description and download link in Appendix A.

brief identification of any open statutory, policy or practical issues.[4] Section III provides a detailed description of all key elements associated with TURN's proposal.[5] Section III(C) includes information responding to the E3 White Paper questions regarding the structure of the MTC, customer eligibility, and funding of the incentive payment.[6] Section IV provides a showing of illustrative rates, cost test results, and other related modeling outputs along with some analysis and conclusions.[7] Section V explains the manner in which TURN's proposal is consistent with the guiding principles and relevant statutory criteria.[8] Section VI offers the likely scope of implementation activities and suggested timelines.[9] A description of TURN's model is provided in Appendix A and sample results from the model are shown in Appendix B.

I. INTRODUCTION

The Commission should seize this opportunity to make an overdue course correction with respect to NEM policy and tariffs. This course correction is needed after the failure of the Commission to make material modifications to legacy NEM policy in the development of the NEM 2.0 tariff adopted in D.16-01-044. In the proceeding that led to the issuance of that decision, TURN actively urged the Commission to develop a new approach to compensating customers with Behind The Meter (BTM) generation resources. Specifically, TURN repeatedly noted the inequities, inefficiencies and growing challenges of continuing to link compensation for BTM resources to retail rates. The final decision issued by the Commission, on a sharply divided 3-2 vote, failed to seize the opportunity for reform, effectively kicked the can down the road, and made only a handful of modest modifications to the legacy NEM tariff.

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[4] ALJ January 28 Ruling, Instruction #1.
[5] ALJ January 28 Ruling, Instruction #2.
[6] ALJ January 28 Ruling, Instruction #5. This section includes all the relevant information requested by the White Paper but does not present the material as responses to specific questions.
[7] ALJ January 28 Ruling, Instruction #3.
[8] ALJ January 28 Ruling, Instruction #3.
[9] ALJ January 28 Ruling, Instruction #4.

As the Commission is aware, Public Utilities Code §2827.1(b)(3) requires that the successor tariff is "based on the costs and benefits of the renewable generation facility" and §2827.1(b)(4) directs the Commission to "ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs." At the time they were enacted, these provisions were widely understood to direct the Commission to end the cost shift associated with NEM and establish a tariff based on the value of BTM resources rather than the poor proxy offered by retail rates.

At the Commission business meeting where D.16-01-044 was adopted, Commission President Picker acknowledged the fact that the Decision does not reach any conclusions regarding the valuation of costs and benefits for the successor tariff and explained that these omissions represent "areas where we really fell short".[10] Commissioner Florio noted, in his oral comments opposing the Decision, that the NEM 2.0 successor tariff being adopted was flawed because AB 327 (Perea, 2013) "requires us to look at the costs and benefits and require that they are appropriately balanced."[11] Commissioner Peterman admitted that the Decision creates a "cost shift" that "is a general concern for all of us."[12] In short, a majority of Commissioners openly acknowledged the failure of the Decision to satisfy key statutory requirements regarding cost shifting.

The Commission's failure to act decisively in 2016 effectively locked in many years of large subsidies paid by the general body of ratepayers to benefit a small group of participating customers. As more customers flock to BTM options in a rational effort to avoid paying rapidly escalating rates driven by a wide array of increasing system costs (including those linked to wildfires and climate change), the base of remaining

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[10] Commissioner Picker oral comments, CPUC business meeting, January 28, 2016. (approximately 56 minute mark).
[11] Commissioner Florio oral comments, CPUC business meeting, January 28, 2016 (approximately 1 hour 19 minute mark).
[12] Commissioner Peterman oral comments, CPUC business meeting, January 28, 2016 (approximately 1 hour 32 minute mark).

customers left to foot these costs continues to shrink. The inequitable outcomes from this accelerating trend must be mitigated through a new compensation structure that fairly calibrates reductions to participating customer bills with the demonstrated incremental value provided by BTM generating and storage resources to all customers and the electrical grid. To the extent that value-based compensation proves insufficient to promote continued customer adoption of BTM resources, the Commission should assess the appropriate amount of subsidization, consider which customers should receive priority access to available subsidies, structure incentives to be efficient and transparent, and explore options for recovering these additional costs from sources other than non-participating customer rates.

The Commission now has an opportunity to restructure NEM tariffs to address the growing cost shift and fairly balance the interests of both participants and non-participants. TURN's tariff proposal is designed to accomplish this balance while providing the Commission with tools that can be used to boost participation rates amongst low-income customers and other underserved customer segments.

II. SUMMARY OF TURN'S TARIFF PROPOSAL

As requested in the January 28 ALJ Ruling, this section provides a summary of TURN's tariff proposal, a comparison with the E3 white paper, an explanation as to how the proposal meets each of the relevant statutory criteria, and a description of any remaining open issues.[13] The three-page summary begins on the following page.

[13] ALJ January 28 Ruling, Instruction #1.

Summary of TURN tariff proposal vs. E3 White Paper Approach (key elements)

Model for export compensation (TURN)	**E3 White Paper**
Net billing	Net billing
Transition Period (TURN)	**E3 White Paper**
Immediately implemented as a rider to existing suite of utility tariff offerings.	Tariff evolves over time towards full marginal cost-based rates.
Level of export compensation (TURN)	**E3 White Paper**
Compensation at avoided cost using most recent Avoided Cost Calculator values modified by the incorporation of actual recorded CAISO market prices to calculate energy supply value (energy, Cap & Trade adder, ancillary services costs, line losses)	Compensation set at estimated avoided cost using adopted Avoided Cost Calculator
Optional long-term export rate (TURN)	**E3 White Paper**
Option for new NEM customers to lock into fixed hourly export rates (time differentiated) for defined terms of 5 or 10 years.	Not explained whether customer would be subject to vintaged ACC values, updated values or some other approach.
Netting timeframe (TURN)	**E3 White Paper**
Export credits determined based on hourly netting with credits applied to monthly bill and any excess (unused) value carried forward for up to 12-months. Any excess production after 12 months can be cashed out via existing Net Surplus Compensation rules.	Monthly netting based on TOU period with excess energy credited at avoided costs.
Import rate schedule (TURN)	**E3 White Paper**
NEM participants can take service under the same existing and future Time of Use (TOU) rate tariffs available to non-NEM customers.	Unique mandatory rate schedule for NEM participants (opt-in for others). Includes fixed charge, grid access charge, and demand charge with TOU energy rates based on marginal cost to collect remaining revenues.
Demand Charges (TURN)	**E3 White Paper**
No new demand charges	New demand charges including on-peak and mid-peak summer demand charge.
Fixed customer charge (TURN)	**E3 White Paper**
No new fixed customer charges	New uniform customer charge ($/month) for all NEM customers to recover fixed costs

Grid Access Charge (TURN)	E3 White Paper
Separate customer-specific monthly charge to recover Nonbypassable, Unavoidable and Shared (NUS) costs for self-consumption by NEM participants. Customer has option of installing second meter or accepting estimated production to calculate self-consumption. NUS costs based on all elements of applicable import tariff except for generation rates, daily fixed charges and the climate credit. Monthly charge would vary based on estimated or metered quantity of customer self-consumption during the relevant month.	Grid Access charge to recover fixed costs not included in a customer charge. May be calculated as $/kW of installed nameplate generating capacity, by maximum non-coincident peak demand, or other approaches.
Market Transition Credit design (TURN)	**E3 White Paper**
One-time up-front payment to offset the present value difference between the 20-year costs of owning/operating a BTM generator and expected bill savings over a target payback period. Payback period of 10 years is proposed for CARE customers. If non-CARE customers are eligible (not TURN's recommendation), MTC should be calculated based on target payback period of 15 years.	$/kWh vintaged payment for all new NEM customers to achieve a target payback which could be set at 7.5 years. E3 did not analyze low-income customer solutions or a minimum bill structure.
MTC Vintages (TURN)	**E3 White Paper**
Updates to MTC value based on material changes in system cost, tax benefits, avoided costs, and retail rates.	Vintages capped based on factors such as number of enrolled customers or installed kW. MTC incorporates system cost and tax benefits.
MTC eligibility (TURN)	**E3 proposal**
Eligibility limited to CARE customers installing retrofits on existing properties. Shorter payback period could be adopted for CARE customers in Disadvantaged Communities and customers eligible for SOMAH, SASH and DAC-SASH programs.	All NEM customers including retrofits and new construction.
MTC cost allocation/collection (TURN)	**E3 White Paper**
Explore options for recovering some or all MTC costs from sources other than rate revenues (GGRF, state general fund). For costs that must be recovered in rates, assign a portion (25-50%) to existing NEM 1.0/2.0 customers with the remainder collected in PPP charges collected from all customers. Any costs collected in rates will occur contemporaneously with up-front payment although financing options could be explored.	MTC cost recovery options include same vintage of NEM customers (after payback has been achieved), future vintages of NEM customers, all NEM customers, all customers as a socialized expense and/or the entire residential class. No discussion of financing costs if incurred.

Paired Storage (TURN)	E3 White Paper
Customers with paired storage moved to a new rate tariff with additional TOU granularity (at least 3 summer/winter periods) and TOU price signals better aligned with grid conditions. No MTC available for storage (beyond existing incentives from other programs). Require storage unit to be discharged during extreme system stress and emergency conditions (CAISO stage 2) in support of grid needs.	No specific proposal. E3 did not analyze the impact of its rate structure on customers with storage.

Demonstration of how TURN's proposal meets each of the relevant statutory criteria

§2827.1(b)(1) Ensure that customer DERs continue to grow sustainably / specific alternatives for disadvantaged communities
Achieves a target payback period of 10 years for CARE customers through an up-front Market Transition Credit and would allow the Commission to set a separate payback period for non-CARE customers and for customers located in Disadvantaged Communities.

§2827.1(b)(2) - terms of service and billing rules for eligible customer-generators.
TURN's proposal would establish clear terms and billing rules (see Section III)

§2827.1(b)(3) Ensure successor tariff is based on costs and benefits of the generator.
Sets export compensation based on the value of exports, provides a generation rate credit for self-consumption, requires participant to pay for second meter or production estimates.

§2827.1(b)(4) Ensure total benefits of the successor tariff to all customers and the electrical system are approximately equal to the total costs.
TURN compares the total costs of the tariff (payments to participants and lost rate revenues) to the total benefits provided to all customers and the electrical system (payments by participating customers and avoided cost values from BTM resource production) with the goal of achieving a 1-1 ratio of benefits to costs. See Section IV for cost-effectiveness results.

§2827.1(b)(5) – Allow projects greater than one megawatt to participate
Continued NEM eligibility for systems greater than 1 MW in size.

§2827.1(b)(6) – transition period for NEM 1.0 customers
Collection of a portion of MTC costs through a surcharge on NEM 1.0 customers may require a limited modification to D.14-03-041.

§2827.1(b)(7) – consideration of NEM reforms in Rulemaking Proceeding
Modifications to the successor tariff made in the current OIR satisfy this requirement.

Important Open Issues
1. Options for collecting costs of Market Transition Credits through non-rate sources
2. Common inputs for calculating/updating MTC incentive levels
3. Potential clarifications/modifications to the NUS methodology
4. Establishment of storage dispatch obligations during emergency conditions

III. DETAILED EXPLANATION OF TURN'S PROPOSED SUCCESSOR TARIFF

TURN's proposed successor tariff consists of four primary tariff elements (one of which is unique to paired storage).[14] Each element addresses a key challenge associated with NEM tariff design. In combination, these elements are designed to ensure that the tariff compensates participating customers based on the benefits of their BTM resource, that shared costs are not shifted to non-participants, and that any subsidies are both transparent and efficiently deployed to achieve a desired payback period for eligible customers.

Balancing the goals of participants and non-participants under a successor tariff structure is challenging under the assumption that a particular payback period should be realized by a participating customer. Any accelerated payback guarantee requires subsidies that exceed the demonstrated benefits of BTM resources to all customers and the electrical grid. The form and magnitude of such subsidies is at the center of the debate over successor tariff design.

TURN's tariff proposal is designed to isolate any subsidies needed to achieve accelerated payback periods, allow for prioritization of access to authorized subsidy amounts, and invite an exploration of options for collecting the costs of subsidies outside of rates. This approach would allow the successor tariff to accommodate increasing levels of participation without causing unexpected long-term rate distortions that create significant affordability issues for all customers.

A. Export compensation

TURN proposes a net billing arrangement that would provide a bill credit tied to the hourly value of exported energy. Credits would be determined based on actual hourly

[14] The four primary elements are export compensation, the customer-specific monthly grid charge, an up-front buydown incentive (Market Transition Credit), and a unique rate for customers with paired storage that includes dispatch obligations in response to emergency or severe system conditions.

exports by the customer's system using the Avoided Cost Calculator (ACC) hourly values modified by the incorporation of actual recorded California Independent System Operator (CAISO) market prices to calculate energy supply value.[15] Export credits would be calculated using an hourly netting approach and applied to customer bills on a monthly basis.[16] This approach to the valuation of exports provides fair value to participants and minimizes the risk that export credits will produce cost shifting.

The export credit should rely on ACC values for the Greenhouse Gas (GHG) adder, GHG portfolio rebalancing, transmission, distribution, generation capacity, and methane leakage. The most recently adopted hourly ACC values for each of these elements should be applied in the year in which power is exported.[17] To avoid excessive complexity relating to locational value, TURN proposes to use a single average hourly value for each IOU service territory for components that vary by location in the ACC model.[18]

The energy value of exports should be credited based on actual recorded hourly wholesale electricity prices. Credits for ancillary services, which are tied to energy value in the ACC model, should be calculated as a defined percentage of observed energy prices.[19] This approach would ensure that bill credits for exported electricity are aligned with wholesale market costs rather than previously generated price forecasts. Reliance on actual market prices would replace the ACC forecasted values for energy, ancillary services, losses and GHG cap and trade.[20]

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[15] CAISO market prices would include the Cap & Trade adder, ancillary services costs, and losses.

[16] Hourly netting means that every individual export hour would produce a credit that is applied to the monthly bill.

[17] For example, this means that the 2022 export values would be set based on the most recently adopted ACC update applicable to 2022.

[18] The ACC model calculates these values by Climate Zone for each IOU.

[19] The 2020 ACC sets avoided ancillary services costs at approximately 0.9% of total wholesale energy costs.

[20] GHG Cap and Trade values are included in the wholesale market price of electricity.

The use of actual market prices would provide premium compensation to participating customers for exports during periods when real-world market prices are high. During such periods, access to real-time wholesale market price information would motivate participants to engage in load shifting, demand response and conservation measures in order to realize higher export credits.[21] This type of customer response could be useful when system conditions are stressed and additional supply is needed to support the entire grid.

TURN also proposes that <u>new</u> participating customers be permitted once, at time of their initial subscription, to opt into fixed hourly export rates, including fixed energy and ancillary service values, for defined terms of 5 or 10 years. The applicable hourly export rates would be fixed based on the most recently updated ACC model values for all hours over the defined term.[22] This option should be limited to new participants in order to provide greater certainty with respect to the value of exports. This certainty would allow a participant to better assess the economic value of an investment in newly built eligible generation over some or all of the anticipated payback period. The option of a fixed export rate would only be available to customers with new generation and could not be selected by legacy NEM customers with existing generation.[23]

The following table summarizes the components and form of export value that would be provided to NEM customers under TURN's proposal:

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[21] TURN's proposal does not include a specific approach to providing actual market price information to NEM customers.
[22] This does not mean that a single rate would be applied, but rather that the ACC values forecast for the entire set of hours over the defined term would be locked in. Exports over the defined term would receive the appropriate hourly value in each year.
[23] TURN does not support offering this opt in customers migrating from NEM 1.0 or 2.0 tariffs.

Value component	Source	Customer options
Distribution	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
Transmission	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
Generation capacity	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
GHG Adder	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
GHG portfolio rebalancing	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
Methane Leakage	ACC	Latest ACC value or 5/10-year lock in (new systems) of forecasted hourly ACC value
Losses	Recorded market prices for actual export hours	Actual hourly market price or 5/10-year lock in (new systems) of of forecasted hourly ACC value
Energy	Recorded market prices for actual export hours	Actual hourly market price or 5/10-year lock in (new systems) of of forecasted hourly ACC value
GHG Cap-and-Trade	Included in recorded market energy costs	Actual hourly market price or 5/10-year lock in (new systems) of of forecasted hourly ACC value
Ancillary Services	Recorded market prices or % of recorded market energy prices	Actual hourly market price or 5/10-year lock in (new systems) of forecasted hourly ACC value

TURN's approach to export compensation depends upon timely and regular updates to the ACC that incorporate up-to-date values for all key avoided cost components. These regular updates will ensure that current year values are regularly recalibrated to reflect more realistic near-term assumptions and to take into account emerging information that informs longer-term value forecasts.

TURN submits that this export compensation approach is straight-forward, aligns with the Commission's existing approach to valuing distributed energy resources, is transparent for participants, and would ensure that bill credits are only provided for demonstrated and approved avoided cost values that reflect benefits to the electricity grid and all customers.

Any surplus credit balances (in excess of charges owed by the customer) on the monthly bill could be carried forward and applied to a future bill for a period of up to 12 months. At the end of 12 months, any remaining balance would be adjusted based on the applicable net surplus compensation methodology required by Public Utilities Code §2827(h)(5).[24] This approach is consistent with existing law, permits the rollover of short-term excess balances and minimizes the potential for cost shifting.

For customers served by CCAs and Direct Access (DA) Providers, TURN recommends that the IOUs provide an export credit equal to the components of the ACC that are related to delivery services provided by the IOU and benefits that are expected to reduce IOU tariffs charged to both bundled and departing load customers (distribution and transmission). All generation, supply and GHG components included in the ACC should be compensated by the CCA or DA Provider serving the individual customer. Since the Commission does not regulate CCA or DA retail rates, the export compensation offered by these retail providers for generation-related values falls outside the scope of this proceeding.

B. Rates charged for imports and self-consumption

TURN proposes that NEM participants be permitted to take service under a wide range of existing (and future) Time of Use (TOU) rate tariffs offered to similar customer without BTM resources. These tariffs would determine charges for imported power. Allowing NEM participants to take advantage of all available tariffs would provide appropriate flexibility and promote the uptake of rate options that are tied to identified

[24] The methodology used to calculate Net Surplus compensation was adopted in D.11-06-016.

end uses such as vehicle electrification, induction stoves, and the use of onsite heat pumps for water heating, space heating and clothes drying.

TURN also proposes a separate monthly charge to recover Nonbypassable, Unavoidable and Shared (NUS) costs associated with self-consumption of output provided by BTM resources. This charge is designed to recover the amount of non-generation costs that would be paid by the participating customer but for the operation of the BTM resource. Unless these costs are collected through a separate charge, the unrecovered amounts would be shifted to all customers including non-participants. TURN proposes a dynamically calculated charge tied to actual (or estimated) customer self-consumption in each month. The total charge would vary by month because the calculated cost responsibility is directly correlated with the amount of actual usage supplied by BTM resources.[25]

The customer's total additional cost obligation would be calculated by multiplying the NUS costs per kilowatt-hour included in the customer's import tariff by the number of kilowatt-hours of customer consumption supplied by BTM resources during the billing cycle. The key calculation is as follows:

Total monthly NUS charge =

kWh of customer self-consumption supplied by BTM resources
x
total NUS costs per kWh

For calculating the portion of customer self-consumption supplied by BTM resources, TURN proposes allowing the NEM customer to choose between two alternative approaches.[26] Under the first approach, the customer could install a second meter on

[25] In a billing cycle when the customer records *de minimus* self-consumption, the monthly NUS charge would also be *de minimus*.
[26] TURN's modeling assumes that the customer is responsible for paying either a $900 second meter cost or a $100 upfront cost for estimating generation.

the BTM resource and provide production data to their utility.[27] The portion of BTM production that is exported (as tracked by the primary customer meter) would be deducted from total production to calculate the remaining amounts used to serve onsite loads. Under the second approach, the customer could agree to have hourly and monthly production from their BTM resource calculated based on engineering estimates that take into account system capacity, location, orientation and any other relevant factors. Metered exports would be deducted from this total amount to determine the number of kilowatt-hours used for self-consumption.

The calculation of NUS cost responsibility should be determined using the customer's existing tariffed rate for imports during the relevant TOU period in which self-consumption occurs reduced by the applicable generation rate (since generation is not being provided). TURN's sample results assume that the generation rate will not include stranded generation costs that are separately identified in the Power Cost Indifference Adjustment (PCIA) and are collected from both bundled service and departing load customers.[28]

TURN's model assumes the following NUS costs that are characterized as to whether they should be classified as nonbypassable or unavoidable/shared costs:

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[27] The meter would either need to be revenue grade or provide comparable accuracy with respect to monitoring and tracking total production.
[28] Pursuant to D.20-03-019, all three IOUs are required to remove PCIA costs from bundled generation rates and collect PCIA costs separately from bundled customers.

Cost category	**Nonbypassable (NBC) or Unavoidable/Shared (U/S)**
Distribution	U/S
Transmission	U/S
Reliability Services (RS)	NBC
New System Generation Costs (NSGC)	NBC
Public Purpose Programs (PPP)	NBC
Wildfire Fund Charge[29]	NBC
IOU securitization for costs relating to wildfires or other undercollections	NBC
Competition Transition Charge	NBC
Power Cost Indifference Adjustment	NBC
Nuclear Decommissioning	NBC
Energy Cost Recovery Account (PG&E)	NBC
PUC Reimbursement Surcharge	NBC

Although TURN believes that all non-generation costs included in the import tariff should be characterized as NUS costs assessed on self-consumption, other parties in this proceeding are likely to dispute this calculation. If the Commission agrees with TURN's proposal for calculating self-consumption cost responsibility based on the quantity of self-consumption but disagrees with the exact categories that should be considered NUS costs, a modified version of TURN's approach can be adopted.

While not recommending any exemptions from cost responsibility (the result of which would be unfair cost shifting to all customers), TURN believes that the following cost categories represent a minimum starting point for calculating NUS costs:

[29] This rate component was previously used to collect DWR bond costs.

Cost category	Rate component typically used for cost recovery
Wildfire costs including mitigation efforts, all vegetation management and excess wildfire liability insurance	Distribution
Catastrophic Events Memorandum Account (CEMA) and Hazardous Substance Mechanism (HSM) balancing accounts	Distribution, Transmission
Transportation electrification programs	Distribution
New System Generation Costs	NSGC
Reliability Services (RS)	NBC
Public Purpose Programs (PPP)	PPP
Wildfire Fund Charge	WFC/DWR bond
IOU securitization for costs relating to wildfires or other undercollections	Separate dedicated rate component
Competition Transition Charge	CTC
Power Cost Indifference Adjustment	PCIA
Nuclear Decommissioning	ND
Energy Cost Recovery Account (PG&E)	ECRA
PUC Reimbursement Surcharge	PUCRF

TURN's identification of the above-listed costs categories as the minimum starting point for determining NUS costs is intended to highlight a number of categories that fall outside the traditional definition of "nonbypassable charges". The list provided in the prior table is illustrative and omits a wide array of costs collected through distribution and transmission rates that are not affected by the decision of a customer to self-generate. Some of these costs are currently recovered in Transmission and Distribution rates and represent shared obligations that, once approved by the Commission for collection from customers, should not be avoidable by NEM participants and shiftable to customers that do not participate in NEM tariffs.

If the Commission declines to adopt TURN's proposed definition of NUS costs but wishes to ensure that some costs included in transmission and distribution rates are fairly collected from all customers, the criteria for determining which costs are included in the NUS definition should be adopted in final decision in this proceeding. In a subsequent implementation phase, the IOUs should be directed to provide a granular breakdown of costs included in distribution and transmission rates so the Commission will be able to assess the portion of such rates that should be collected in the form of a monthly charge on self-consumption.

All traditionally-defined nonbypassable charges should be included in the NUS definition. These include departing load charges for stranded generation costs collected through the PCIA, reliability resources and new system generation, public purpose programs (including the CARE discount), and nuclear decommissioning. None of these costs should be avoidable by a customer opting for self-generation. To the extent that such costs are not collected from NEM participants, the shortfall would be collected through higher overall rates that are primarily borne by non-participants.

The Commission should recognize that TURN's approach to the collection of NUS costs carefully calibrates cost responsibility with actual customer usage over the course of each month. As compared to a lump-sum fixed charge, or a scaled charge based on BTM system size, TURN's proposal assigns costs fairly to customers and accounts for a wide array of usage and self-consumption patterns. This approach is fair to NEM customers and ensures that non-participants are not required to disproportionately pay for cost obligations that are not offset by BTM production and are properly shared by all customers.[30]

C. Up-front incentive payment (Market Transition Credit)

TURN's proposal includes a Market Transition Credit (MTC) in the form of a one-time upfront subsidy payment to low-income customers to ensure sustainable growth and achieve equity goals.[31] TURN's proposed MTC is designed to reflect the entirety of any incentives to NEM participants. While the remaining elements of TURN's proposal

[30] In a wide array of proceedings, TURN continues to fight against unreasonable utility revenue requirement requests and for utility shareholders absorbing costs relating to poor performance. TURN's proposal in this proceeding is not meant to suggest that any customers should be forced to bear any unreasonable or excessive costs.
[31] These goals are identified in Public Utilities Code §2827.1(b)(1).

would fairly compensate NEM participants for the value they provide to all customers and the electrical grid, the MTC buydown represents a pure subsidy designed to achieve defined customer adoption objectives. Including this incentive in a separate MTC would ensure that all authorized subsidies are fully transparent, provided over a discrete timeframe and coordinated to reduce the amount of up-front investment by a participating customer. Moreover, the separation of such incentives from other payments should allow for creative strategies to identify funding sources other than retail rates to cover some or all of these costs.

Unlike the E3 white paper that would structure an MTC as an incremental payment on a $/kWh basis over a period of many years, TURN proposes a one-time payment provided as lump sum that represents a direct offset to purchase costs.[32] Frontloading the MTC would serve two key objectives. First, the participating customer would be able to apply the entire amount to reduce the costs of new investment as a direct offset at the time of purchase. By contrast, alternative approaches that provide enhanced export compensation or discounted NUS cost responsibility over an extended period of time would offer total value that is difficult for participants to initially assess and none of the incentive would be available to offset any initial cost or up-front investment. Second, apart from these one-time costs there would be no ongoing subsidies to be recovered from all customers and no continuing concern about the cost-shifting impacts of participating customers. By contrast, approaches that provide above-market compensation over many years would perpetuate cost shifting and lead to a long 'tail' of excessive payment obligations that could ultimately exceed their initial expectations and create unanticipated rate distortions for nonparticipants.

An up-front MTC is consistent with California's longstanding approach to supporting BTM solar and other distributed energy resources over the past several decades.

[32] Pursuant to the January 28 Ruling of ALJ Hymes, the description of TURN's proposal in this section addresses the questions raised in the E3 White Paper (page 33) regarding options for structuring and financing an MTC.

Starting in 1998, the California Energy Commission administered up-front rebates for solar and small wind through the Emerging Renewables rebate program. In 2007, the CPUC launched the California Solar Initiative (CSI) to provide up-front rebates for smaller BTM solar systems.[33] These programs were hailed as successful efforts to stimulate the solar market and became widely accepted by customers and vendors. Rebates were typically used to offset system installation costs. Although neither the CEC nor CSI programs provide new rebates to the general market, the Commission continues to rely on up-front funding support for low-income customer solar adoption through the Solar on Multifamily Affordable Housing (SOMAH) program and the Disadvantaged Communities Single-Family Solar Homes (DAC-SASH) program.

For CARE customers, TURN recommends setting the MTC based on an assumed payback period of 10 years. This timeframe represents a reasonable horizon for recovering the costs of an initial investment for an eligible participant. The level of the up-front MTC would be a $/kW payment that varies based on the installation year, the assumed benefit/cost ratio, and a target discounted payback period. Details on TURN's methodology for calculating the MTC are included in the model described in Appendix A and available to all parties for review in detail.[34]

In this proceeding, the Commission can adopt a method for calculating the MTC that regularly incorporates updated data on system costs, tax incentives, and other key inputs. Unless warranted by more frequent material changes in key input values, the MTC should be reviewed every 3-5 years to ensure that the amounts accurately reflect all key inputs relevant for a system to be installed in the following year. Although the level of the MTC may not be required to change year-to-year, any significant events

[33] The CSI offered capacity-based up-front rebates for residential systems and performance-based rebates for larger systems typically installed on commercial and institutional customer premises.
[34] The payback logic can be found in the "DER Pro Forma Incentives" tab of the model. Key input assumptions and results are shown in the "Results Dashboard" tab.

(like new or sunsetting tax credits) should justify material adjustments to the MTC level.

Because the total costs of an up-front subsidy would be significant to achieve a 10-year payback across a broad base of customers, TURN supports limiting MTC eligibility to CARE eligible customer retrofits on existing properties. These customers face the largest challenges in achieving reasonable payback periods and should be the focus of future incentives to achieve equity and affordability objectives. The Commission should also evaluate different payback periods for MTCs available to low-income customers located in disadvantaged communities and customers eligible for the Solar on Multifamily Affordable Housing (SOMAH) program, the Single-family Affordable Solar Homes (SASH) Program and the Disadvantaged Communities - Single-family Solar Homes (DAC-SASH) program. The availability of MTCs for participation in these programs could supplement existing funding sources used to support these initiatives and take into account other available incentives for these customers. The Commission could also expand MTC eligibility, or authorize a different payback timeframe, for other disadvantaged customer subgroups to support various policy, equity and environmental objectives.

TURN does not support making the MTC available to new residential construction covered by the Title 24 solar requirements. Since solar installation on these properties would be required, there is no basis for providing an additional incentive and the availability of an MTC would therefore have no impact on adoption rates. If a funding source other than retail rates can be identified, MTCs could be expanded to include Title 24 installations.

Absent the use of a funding source outside of retail rates, TURN is not proposing to make an MTC available to non-CARE customers. If the Commission wishes for non-CARE residential customers to be eligible, the payback period should be set at 15 years for determining an up-front incentive level. This payback period would ensure that participating customers receive net benefits from their investment. Assuming an average non-CARE system size of 4 kW and a $1/watt (AC) up-front MTC applied to 150,000 annual non-CARE customer installations, the total cost would be approximately $600 million per year.

In establishing an MTC structure, the Commission should express a strong preference for identifying sources of funding other than rate revenues from all customers. The most suitable sources are state general fund monies including Cap-and-Trade funds (from the Greenhouse Gas Reduction Fund) that could be used to pay for some or all of the MTCs paid to participants. TURN's model allows for the availability of external state funds to be used to calculate the impact on the Rate Impact Measure (RIM) test results.[35] Funding some or all of the MTC costs through sources other than retail rates would materially improve RIM test outcomes.

Although TURN recognizes that the Commission cannot order the Legislature to appropriate money for this purpose, the Commission can express a preference for external funding and adopt a mechanism that is capable of accommodating external funding that becomes available over time. The Commission could also condition the expansion of the MTC to certain customer groups (such as non-CARE customers) on the availability of adequate funding from alternative sources.

For MTC costs that must be recovered in rates, TURN offers two approaches to collection. First, the Commission should adopt a new surcharge applied to existing non-CARE NEM 1.0 and 2.0 customers to collect a portion of the MTC costs.[36] Existing CARE NEM customers would be exempted from this surcharge. This approach is justified because of the enormous financial benefits that legacy NEM customers

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[35] See "Results Dashboard" tab, Allocation of Buydown Incentive options.
[36] For a discussion of legal issues associated with the application of this surcharge to non-CARE NEM 1.0 customers, see Section V(B). For NEM 2.0 customers, the Commission has the express authority to "revise the standard contract or tariff as appropriate to achieve the objectives of this section." (Cal. Pub. Util. Code §2827.1(b))

continue to realize under the existing tariffs and the longer payback periods for CARE customers.[37] Assigning non-CARE NEM 1.0 and 2.0 customers the responsibility to provide 25% of $200 million in annual MTC funding would result in a new monthly charge of approximately $4.[38] TURN recommends using this 25% assumption as a starting point for assigning MTC cost responsibility to legacy non-CARE NEM customers and considering a 50% allocation as an upper bound. TURN's model calculates the monthly charge for a defined percentage of MTC costs to be collected from legacy NEM customers and incorporates this result into the Ratepayer Impact Measure (RIM) test results.[39]

Second, TURN recommends collecting the remaining MTC costs from all customers through the Public Purpose Program charge allocated on an equal cents per kilowatt-hour basis. This approach would spread cost responsibility fairly and is consistent with the allocation of cost responsibility for the CARE discount. The collection of remaining MTC costs via PPP recognizes that the incentive is designed to achieve important environmental and equity goals, similar to other cost categories recovered in this manner.

D. Paired storage rate and dispatch obligations

TURN recognizes that NEM customers will increasingly adopt paired energy storage as part of BTM installations. Although the economics of paired storage are not currently compelling for residential customers due to high installation costs, likely reductions in

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[37] The disparate payback periods for CARE and Non-CARE customers under existing NEM tariffs is highlighted in Section IV.

[38] TURN uses $200 million as an illustrative amount that represents the cost of providing a $1.50/watt (AC) up-front incentive to approximately 50,000 new PG&E CARE installations per year. As indicated in TURN's results, the incentive achieving a 1.0 payback at year 10 ranged from approximately $1.5 to $1.6 per watt for CARE customers located in inland and coastal regions.

[39] See "Results Dashboard" tab, Allocation of Buydown Incentive options. Although the RIM results are not changed as a result of allocating MTC costs to legacy NEM customers, the impact on non-participants is reduced.

equipment costs in the coming years could change the overall value proposition. In the near-term, residential storage installations are likely to be justified by concerns over resiliency and the ability to remain energized during short-term unplanned outages, during intentional multi-day utility shutoffs triggered by imminent wildfire risks, and in the event of natural disasters. The value of resiliency may be sufficient to motivate customers to invest in paired storage even when the system is not expected to yield sufficient bill savings to justify the initial investment. Therefore, TURN does not believe that the successor tariff should be designed to provide a specific payback period for paired storage systems or that the MTC should incorporate up-front incentives for storage adoption.

The NEM tariff should be designed to incentivize optimal dispatch behavior by paired storage to support broader grid needs. To that end, TURN proposes that customers with paired storage be placed into a separate rate tariff with additional time of use (TOU) granularity and TOU price signals that are better aligned with grid conditions to support optimal dispatch that benefits the grid and all customers. TURN recommends that the Commission authorize paired storage tariffs with at least 3 TOU periods in the summer and winter seasons and an optional Critical Peak Pricing component. These features will incentivize optimal dispatch and provide appropriate compensation for performance during periods of peak need. TURN's model assumes that paired storage charges only from the onsite renewable generation and engages in one full discharge cycle per day during the hours that comprise the peak period.[40]

TURN also proposes requiring any paired storage unit participating in the successor tariff to discharge during certain extreme system stress and emergency conditions in support of overall grid needs. In order to accommodate this requirement, paired storage

[40] TURN's proposal does not expressly address the potential for paired storage to participate in demand response markets or receive other specific payments for contributions to Resource Adequacy. As a result, these potential revenue streams are not incorporated into TURN's model.

should have the capability to respond to remote dispatch instructions from a third-party aggregator, the IOU or a CCA/DA provider, or the California Independent System Operator.[41] This capability should be used to require dispatch to a pre-determined minimum capacity level during a Stage 2 emergency or during extreme summer net peaks when CAISO has identified concerns about generation insufficiency.[42] Participants should be compensated for this dispatch based on market prices in the relevant hours. The obligation to accept remote dispatch and to discharge under these conditions is intended to address the countervailing motivation of customers to resist discharging if there is a known risk of an extreme weather event or widespread outage.[43] Requiring that such systems operate in a manner consistent (and not at odds) with grid needs during severe conditions should be a condition precedent to eligibility for successor tariff participation for paired storage resources.

E. Virtual Net Energy Metering

TURN's proposal would support Virtual Net Energy Metering (VNEM) by reforming export compensation to provide participating customers with a credit against their monthly bills equal to the avoided cost values described in Section III(A). However, TURN is not proposing any new or modified VNEM tariffs at this time. After assessing final Commission action to reform the basic NEM tariff, TURN will make recommendations regarding the manner in which VNEM should be modified or expanded. TURN's reluctance to propose such changes at this time is based on the concerns over the reasonableness of permitting excessive export compensation values to

[41] Issues relating to the technical ability of storage to export are outside the scope of TURN's proposal and are being addressed elsewhere.

[42] The CAISO defines a stage 2 emergency notification as a situation where "The ISO has taken all mitigating actions and is no longer able to provide its expected energy requirements. Requires ISO intervention in the market, such as ordering power plants online." (https://www.caiso.com/documents/systemalertswarningsandemergenciesfactsheet.pdf)

[43] For example, Tesla Powerwall systems have a "storm mode" that, when a severe weather event is approaching, automatically charges the battery to its maximum capacity and holds that state of charge until the event is over. (https://www.tesla.com/support/energy/powerwall/mobile-app/additional-modes)

be traded and applied to separate customer accounts if such a mechanism would create substantial cost shifting.

F. Interconnection charges and metering requirements

TURN's proposal assumes that participating customers pay upfront and ongoing interconnection fees similar to those currently in effect.[44] TURN's proposal will also require either a second meter (for onsite generation) or the participating customer's acceptance of an estimate of generation in order to calculate the monthly grid charge. Participants would be responsible for paying the incremental cost of a second meter or incremental upfront costs associated with estimating generation output.

G. Treatment for systems 1 megawatt and larger

Pursuant to Public Utilities Code §2827.1(b)(5), the NEM successor tariff shall allow projects larger than 1 MW to be sized to onsite loads so long as there is no significant impact on the distribution grid.[45] TURN has not proposed any differential treatment of systems larger than 1 MW under its tariff and assumes in its results that all systems are sized to provide 100% of a customer's first year load.

H. Safety issues

TURN has not identified any particular safety issues relating to the successor tariff and does not include any elements relating to safety as part of its proposal.

[44] In TURN's model, these costs are incorporated into the upfront system cost paid by the customer.
[45] §2827.1(b)(5).

IV. SAMPLE RESULTS AND COST-EFFECTIVENESS SHOWINGS FOR TURN'S TARIFF PROPOSAL

A. Development of cost test results pursuant to Commission guidance

As requested in the January 28 ALJ Ruling, this section provides the justification for the cost-effectiveness of TURN's tariff proposal.[46] Consistent with the direction provided in D.21-02-007, TURN's modeling displays the cost-effectiveness results for its tariff proposal under the four primary Standard Practice Manual approaches – Total Resource Cost (TRC) test, Program Administrator Cost (PAC) test, Ratepayer Impact Measure (RIM) test, and Participant Cost Test (PCT).[47] For purposes of modeling avoided costs, TURN relies on the CPUC's Avoided Cost Calculator (ACC).[48]

In D.21-02-007, the Commission explained that, pursuant to D.19-05-019, the TRC is the "primary test" for use in assessing the cost-effectiveness of Distributed Energy Resources but that results from the PAC, PCT, and RIM tests should also be considered for purposes of the NEM successor tariff.[49] TURN provides these results along with results for various customer types (and climate zones) showing the expected discounted payback period, the amount of an MTC incentive under various target payback periods (10 and 15 years), and the anticipated monthly NUS charge.

B. Summary results for PG&E customers

TURN provides summary results for four different types of CARE and non-CARE PG&E customers under four different scenarios. Additional results for these customers are provided in Appendix B. A comprehensive set of inputs and results for these customers is available in TURN's model which is described in Appendix A (and can be downloaded via a provided internet link). The four scenarios are as follows:

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[46] ALJ January 28 Ruling, Instruction #3.
[47] D.21-02-007, page 12.
[48] Although TURN proposes to compensate customers for the energy value of exports using actual CAISO market prices (rather than assumed values in the ACC), the cost-effectiveness model assumes ACC values for these cost components.
[49] D.21-02-007, pages 12, 35-36.

#1 - Existing NEM 2.0

#2 – TURN tariff proposal with no Market Transition Credit (MTC) buydown

#3 – TURN tariff proposal with MTC buydown based on a target participant payback period of 10 years with 100% of buydown costs included in the rates of all customers.

#4 – TURN tariff proposal with MTC buydown based on a target participant payback period of 15 years with 25% of buydown costs included in the rates of all customers.

In addition, TURN provides illustrative results for the surcharge levels applied to existing NEM 1.0 and 2.0 customers (CARE participants excluded) to recover 25% and 50% of the MTC buydown costs under each scenario and customer type.

Due to constraints obtaining the necessary data from the IOUs in a timely manner, TURN is only able to provide results for PG&E at this time. TURN expects to have complete data for all three IOUs prior to the submission of direct testimony and will provide results for different customer types of all three IOUs at that time.

PG&E Scenario	CARE Dual Fuel Coastal	CARE Dual Fuel Inland	CARE All Electric Coastal	CARE All Electric Inland
#1 -- EXISTING NEM 2.0				
RIM	0.725	0.642	0.753	0.660
PCT	1.196	1.191	1.150	1.159
TRC	0.871	0.772	0.862	0.766
PAC	15.736	24.534	12.967	19.570
Discounted Payback Years	15	15	16	15
#2 -- TURN SUCCESOR TARIFF - NO MTC BUYDOWN				
RIM	1.146	1.224	1.120	1.191
PCT	0.764	0.692	0.756	0.691
TRC	0.810	0.740	0.791	0.728
PAC	6.456	10.015	5.336	8.007
Discounted Payback Years	> 20	> 20	> 20	> 20
Year 1 NUS Monthly Charge ($)	$25.26	$43.22	$21.33	$33.55
#3 -- TURN SUCCESSOR TARIFF WITH MTC BUYDOWN @10-YEAR PAYBACK 100% OF MTC COSTS INCLUDED IN RIM				
RIM	0.666	0.623	0.655	0.614
PCT	1.229	1.195	1.225	1.195
TRC	0.810	0.740	0.791	0.728
PAC	6.456	10.015	5.336	8.007
Discounted Payback Years - prior to buydown	> 20	> 20	> 20	> 20
Discounted Payback Years - after buydown	10	10	10	10
Year 1 NUS Monthly Charge ($)	$25.26	$43.22	$21.33	$33.55
Upfront Capex Buydown $	$4,653	$9,051	$3,870	$7,225
Upfront Capex Buydown $/kW	$1,522	$1,629	$1,544	$1,636
#4 -- TURN SUCCESSOR TARIFF WITH MTC BUYDOWN @15-YEAR PAYBACK 25% OF MTC COSTS INCLUDED IN RIM				
RIM	1.011	1.027	0.989	1.004
PCT	1.107	1.091	1.105	1.091
TRC	0.810	0.740	0.791	0.728
PAC	6.456	10.015	5.336	8.007
Discounted Payback Years - prior to buydown	> 20	> 20	> 20	> 20
Discounted Payback Years - after buydown	15	15	15	15
Year 1 NUS Monthly Charge ($)	$25.26	$43.22	$21.33	$33.55
Upfront Capex Buydown $	$3,434	$7,188	$2,882	$5,740
Upfront Capex Buydown $/kW	$1,124	$1,294	$1,150	$1,300
SURCHARGE FOR NEM 1.0/2.0 CUSTOMERS TO RECOVER % OF MTC COSTS (SCENARIO 4)				
$/month Non-CARE NEM 1.0/ 2.0 - 25% share	$7.96	$16.67	$6.68	$13.31
$/month Non-CARE NEM 1.0/ 2.0 - 50% share	$15.93	$33.34	$13.37	$26.62

PG&E Scenario	NonCARE Dual Fuel Coastal Large No EV	NonCARE Dual Fuel Inland Small No EV	NonCARE All Elec Coastal Small No EV	NonCARE All Elec Inland Small No EV
#1 -- EXISTING NEM 2.0				
RIM	0.434	0.411	0.459	0.418
PCT	1.893	1.733	1.769	1.705
TRC	0.903	0.763	0.866	0.764
PAC	51.651	16.934	14.035	17.615
Discounted Payback Years	7	8	8	8
#2 -- TURN SUCCESOR TARIFF - NO MTC BUYDOWN				
RIM	1.120	1.024	1.013	1.033
PCT	0.852	0.766	0.834	0.764
TRC	0.881	0.719	0.799	0.722
PAC	20.985	6.941	5.768	7.216
Discounted Payback Years	> 20	> 20	> 20	> 20
Year 1 NUS Monthly Charge ($)	$138.87	$50.24	$37.45	$50.21
#3 -- TURN SUCCESSOR TARIFF WITH MTC BUYDOWN @10-YEAR PAYBACK 100% OF MTC COSTS INCLUDED IN RIM				
RIM	0.687	0.591	0.642	0.593
PCT	1.265	1.224	1.256	1.224
TRC	0.881	0.719	0.799	0.722
PAC	20.985	6.941	5.768	7.216
Discounted Payback Years - prior to buydown	> 20	> 20	> 20	> 20
Discounted Payback Years - after buydown	10	10	10	10
Year 1 NUS Monthly Charge ($)	$138.87	$50.24	$37.45	$50.21
Upfront Capex Buydown $	$13,503	$5,687	$3,769	$5,940
Upfront Capex Buydown $/kW	$1,327	$1,492	$1,386	$1,497
#4 -- TURN SUCCESSOR TARIFF WITH MTC BUYDOWN @15-YEAR PAYBACK 25% OF MTC COSTS INCLUDED IN RIM				
RIM	1.015	0.902	0.923	0.908
PCT	1.123	1.104	1.119	1.104
TRC	0.881	0.719	0.799	0.722
PAC	20.985	6.941	5.768	7.216
Discounted Payback Years - prior to buydown	> 20	> 20	> 20	> 20
Discounted Payback Years - after buydown	15	15	15	15
Year 1 NUS Monthly Charge ($)	$138.87	$50.24	$37.45	$50.21
Upfront Capex Buydown $	$8,871	$4,199	$2,545	$4,397
Upfront Capex Buydown $/kW	$872	$1,102	$936	$1,108
SURCHARGE FOR NEM 1.0/2.0 CUSTOMERS TO RECOVER % OF MTC COSTS (SCENARIO 4)				
$/month Non-CARE NEM 1.0/ 2.0 - 25% share	$20.57	$9.74	$5.90	$10.20
$/month Non-CARE NEM 1.0/ 2.0 - 50% share	$41.14	$19.47	$11.80	$20.39

C. Analysis of Summary Results

These results show that for both CARE and non-CARE customers, TURN's tariff proposal requires an MTC to ensure that Participants are able to realize net benefits over a period of less than 20 years. However, the collection of MTC costs in rates results in cost shifting to nonparticipants. To the extent that cost shifting is permitted, the Commission should determine how to prioritize the deployment of incentives in order to constrain their total cost. Unless MTC funding is financed largely from sources other than retail rates, it is not possible to achieve a Successor Tariff design that avoids cost shifting to non-participants. If a significant portion of the MTC can be financed from sources other than retail rates, a successor tariff can balance the twin goals of Participant net benefits and no cost shifting to non-participants. Support for these conclusions is provided in the following paragraphs.

With respect to the TRC results, TURN notes that this calculation does not materially vary based on the selected tariff design. Consistent with the Standard Practice Manual, the TRC test compares benefits (ACC avoided costs + up-front participant costs paid to the IOU) with costs (participant costs of owning/operating a system, federal tax impacts, and utility up-front and ongoing costs to administer the tariff). As a result, the only methods of materially changing the results of the TRC test are to modify the resource type (i.e., wind, paired storage), modify the avoided cost assumptions[50], or assume different PV system costs paid by the participant and/or utility administration costs.

TURN's results show that the TRC for NEM 2.0 differs from the successor tariff results because of the assumed incremental cost of estimating or metering generation under

[50] In D.21-02-007, the Commission directed parties to rely on the ACC for this purpose and not to request changes in the values for purposes of modeling tariff cost-effectiveness of successor tariff proposals.

TURN's approach.[51] The actual design of the tariff, including various approaches to export compensation, netting, self-consumption, and grid charges, has no impact on the TRC results. Since the key features of tariff design do not affect TRC values, the TRC is not helpful in considering the alternative tariff proposals presented by various parties.

TURN's results indicate that under the assumptions described in Appendix A, the TRC is less than 1.0 for CARE and non-CARE customers. This result shows that the present value of avoided costs of behind-the-meter of solar PV is not expected to exceed the present value of system costs. Under the TRC, this means that the installation of solar PV as a behind-the-meter resource is not cost effective from a total resource cost perspective. To the extent that the Commission relies on the TRC to guide its decisionmaking in this proceeding, the results show that measures designed to increase solar resource deployment are not cost justified.

The PAC test measures the net costs of the program based on the costs incurred by the program administrator and avoided costs. This test ignores both costs spent by participants to purchase/lease and operate a BTM resource and the bill savings/lost revenues that are used to assess cost shifting. Similar to the TRC test, the actual design of the tariff, including various approaches to export compensation, netting, self-consumption, and grid charges, has no impact on the PAC test results. The different results under the PAC test between existing NEM 2.0 and TURN's proposal are attributable to the inclusion of incremental participant costs for estimating or metering generation. Because of the narrow scope of the PAC test, it is not useful for assessing the cost-effectiveness of successor tariff options.

The results of the RIM and PCT tests are far more relevant for assessing the impact of a successor tariff on participating customers and all customers because they account for

[51] TURN assumes that the participating customer would either pay for a second production meter or for the incremental costs associated with estimating production from their generating unit.

participant bill reductions. These bill reductions have two effects – they benefit participants and shift cost responsibility to all customers. For a successor tariff design to be sustainable, it must balance the objectives of both participating and non-participating customers. The Commission should therefore focus on the PCT and RIM results in order to evaluate the differences between successor tariff options.

The PCT reflects the value proposition for the participating customer and is a proxy for cost-effectiveness from their perspective. For the PCT, a result of at least 1.0 indicates that, for the participant, the present value of compensation has covered costs. Existing NEM 2.0 tariffs yield a PCT of 1.7-1.9 for non-CARE customers and ~1.15 for CARE customers. This result highlights both the disparities between the value of NEM 2.0 to CARE and non-CARE participants and the extent to which non-CARE customers are currently oversubsidized.

TURN's proposed tariff without any subsidies yields a PCT of 0.7-0.75 for CARE customers and 0.75-0.85 for non-CARE customers. With MTC incentives calibrated to provide a 10-year payback, the PCT rises to 1.2-1.25 for both non-CARE and CARE customers. With the MTC set to provide a 15-year payback, the PCT is ~1.1 for both non-CARE and CARE customers. These results show that the availability of an MTC will allow for participants to realize positive net benefits and can equalize the disparities between CARE and non-CARE customers.

The RIM test compares the benefits of the tariff to all customers (avoided cost benefits and program fees paid by participants) with the costs to all customers (participant bill savings resulting in revenue losses that are reallocated to all customers, costs of MTC incentive payments, and IOU incurred program costs collected in rates). For the RIM, a result of at least 1.0 indicates that present value costs do not exceed present value benefits, an outcome that means no costs have been shifted from participants to all ratepayers. The RIM test is the only approach that properly accounts for the impact of NEM tariff design on all customers.

Existing NEM 2.0 tariffs show a RIM of ~0.43 for non-CARE customers and ~0.7 for CARE customers. These results demonstrate the significant cost shift associated with current NEM tariffs and highlight the larger cost shift tied to non-CARE customer participation. This result is consistent with the findings of disparate impacts between CARE and non-CARE customers under the other cost tests.

TURN's proposed tariff without any MTC buydown costs collected in rates results in RIM of 1.0-1.1 for non-CARE customers and 1.1-1.2 for CARE customers. Including all the MTC costs in rates under a 10-year payback assumption reduces the RIM to ~0.65 for both CARE and non-CARE customers. This result demonstrates significant cost shifting to all customers if a 10-year payback is required with the entire subsidy being collected in rates. TURN also modeled a 15-year payback period with 25% of MTC costs collected in rates. This assumption yielded a RIM of ~1.0 for CARE customers and 0.9-1.0 for non-CARE customers. This type of RIM result should be the Commission's objective in order to ensure that a successor tariff does not shift costs from participants to all customers.

TURN's results show that the discounted payback period under the existing NEM 2.0 tariff is 7-8 years for non-CARE customers and 15-16 years for CARE customers.[52] These results confirm the general understanding that NEM 2.0 is far more beneficial for non-CARE customers due to the higher average rates that are avoided through the operation of a BTM resource. TURN's proposal would reverse this disparate outcome by establishing a payback period of 10 years for CARE customers and, if the Commission

[52] The E3 White Paper shows a shorter 4.1-year payback period under existing NEM 2.0 tariffs. Since there are no workpapers for the E3 calculations, it is not possible to reconcile the differences between the E3 and TURN approaches to calculating payback periods. It appears that E3 relies on SDG&E retail rates to perform this calculation and uses a simple rather than a discounted payback. TURN's results are currently limited to PG&E customers (who pay lower retail rates than SDG&E customers). In direct testimony, TURN will include payback results for SCE and SDG&E customers.

wishes, setting the MTC to allow a 15-year payback for non-CARE customers. This approach prioritizes the deployment of incentives to benefit low-income customers rather than the existing policy of disproportionately subsidizing higher income customers.

V. CONSISTENCY WITH GUIDING PRINCIPLES AND RELEVANT STATUTORY CRITERIA

As requested in the January 28 ALJ Ruling, this section explains the manner in which TURN's proposal addresses each of the Guiding Principles adopted in D.21-02-007 and is consistent with the statutory requirements governing the successor tariff enumerated in Public Utilities Code §2827.1.[53] In addition, this section clarifies that TURN's proposal faces no identified tax concerns, is not barred pursuant to Public Utilities Code §381, and is consistent with the treatment of Net Metering permitted under the Public Utility Regulatory Policies Act (PURPA).

A. <u>Consistency with the adopted Guiding Principles</u>

1. *Principle #1 - A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1*

To determine compliance with all the relevant statutory requirements, TURN reviews each in sequence and explains the element of its tariff proposal that responds to the relevant statutory direction. For each of the individual provisions of §2827.1(b), TURN offers a showing of compliance and a brief explanation without repeating the details of its tariff proposal.

> *2827.1(b)(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.*

[53] ALJ January 28 Ruling, Instructions #2(k) and #3.

TURN does not believe that Public Utilities Code §2827.1(b)(1) requires the Commission to adopt any particular quantitative methodology for determining whether a successor tariff would permit "sustainable" growth of renewable distributed generation. D.21-02-007 declined to adopt a formal definition of "grow sustainably".[54] TURN believes that this requirement is satisfied if the successor tariff is found to be cost-effective for participants over a reasonably defined timeframe. The adoption of TURN's proposed tariff would satisfy this requirement and allow continued growth in BTM solar installations. TURN's tariff proposal establishes a target payback period of 10 years for CARE customers and should allow these customers to make investments and other financial commitments to new BTM systems. If the Commission finds that a different payback period is warranted to support a finding that BTM renewable generation will "grown sustainably", or that all participating customers should be guaranteed a specific payback period, it may adapt TURN's proposal to achieve that result through a different up-front MTC.

Although TURN's proposal does not include new tariff options for residential customers located in disadvantaged communities (DACs), the Commission recently adopted several programs to increase access to solar for residents of disadvantaged communities located within PG&E's, SCE's, or SDG&E's service territory. These programs include the Solar on Multifamily Affordable Housing (SOMAH) program, the DAC-Single Family Solar Homes (DAC-SASH) program, the DAC-Green Tariff program, and the Community Solar Green Tariff program.[55] The SOMAH and DAC-SASH programs include up-front incentive funding to lower the costs to participating customers.

TURN's tariff proposal would layer on top of these existing initiatives and provide an additional upfront payment through the MTC, if needed, to ensure that the system achieves a payback within 10 years. If warranted, the Commission could adapt TURN's

[54] D.21-02-007, page 11.
[55] D.17-12-022, D.18-06-027.

up-front MTC to provide additional incentives, and a lower payback period, for eligible customers living in DACs. The availability of this tool would allow the Commission to use the existing tariff design to accomplish equity objectives and promote solar deployment in DACs. Because TURN's tariff design places the entire subsidy amount in the MTC, the Commission can easily recalibrate the MTC for specific customer subgroups to ensure that additional funding is provided to the intended beneficiaries. By contrast, proposals to increase NEM compensation for all customers would only provide a portion of the additional benefits to low-income customers living in DACs. For these reasons, TURN submits that the availability of its tariff would constitute a superior approach to satisfying the statutory directive relating to disadvantaged communities.

2827.1(b)(2) Establish terms of service and billing rules for eligible customer-generators.

TURN's tariff proposal would establish clear terms of service and billing rules for all NEM participants. New terms and rules are described in Section III. Existing terms and rules under the current successor tariff that do not conflict with TURN's tariff proposal would remain unchanged. TURN's proposal therefore complies with this requirement.

2827.1(b)(3) Ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.

As explained in Section III, TURN's proposed tariff is based explicitly on the costs and benefits of the renewable electrical generation facility. Export compensation would be based on avoided costs and credit for self-consumption would be tied to the tariffed generation rate. Both of these approaches link credits under the tariff to the relevant benefits provided by the generating facility. Similarly, the target payback periods used to set the MTC would be tied to the costs of the generating facility. Changes in facility costs over time would result in adjustments to the MTC amount. As a result, the costs of the facility are explicitly taken into account.

While TURN's proposal conforms to this statutory requirement, the existing NEM 2.0 tariff does not. Under NEM 2.0, the tariff provides export compensation based on the total retail rate levels for the customer rather than the benefits of the generation facility. The NEM 2.0 approach unreasonably assumes that the renewable electrical generation facility provides fewer benefits if located behind the meter of a CARE customer as opposed to a non-CARE customer. There is no rational basis for assuming that the benefits of a renewable generating facility depend upon the household income of the NEM customer. Moreover, the existing NEM 2.0 tariff gives no consideration to the costs of the generating facility and makes no adjustments to any of its provisions based on changes in costs over time.

For these reasons, the Commission should therefore find that TURN's proposal represents far better alignment with this provision than the existing NEM 2.0 tariff.

> *2827.1(b)(4) Ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.*

As explained in Section III, TURN's tariff proposal is designed to link the total costs of the tariff (payments to participating customers and lost rate revenues) to the total benefits provided to all customers and the electrical system (payments by NEM customers and avoided cost values from BTM resource production). This approach is best captured by the RIM test results which measure any imbalance between these benefits and costs.

TURN's tariff proposal would compensate NEM customers for the benefits provided to all customers and the electrical system. The only portion of the compensation not tied to identified benefits is the MTC buydown, which is provided to CARE customers in order to ensure that they achieve a reasonable payback period. To the extent that the costs of the MTC are recovered from sources outside of electricity rates, the RIM test results would remain unaffected.

TURN recognizes that the Commission wishes to assess the TRC results to determine adherence to this statutory requirement in addition to the RIM, PCT and PAC outcomes. However, the TRC results do not calculate the total costs and benefits of the tariff to all customers because they ignore the impact of the tariff on participant bill savings and the resulting the rate impacts on non-participants.[56] As a result, the TRC values are relatively constant across a wide range of successor tariff options, making it impossible to use the TRC to assess one tariff that provides lower compensation versus another that provides higher compensation.[57]

It would be unreasonable for the Commission to conclude that the Legislature intended for the actual type, design and level of tariffed compensation to be irrelevant to a determination as to whether a successor tariff meets this statutory test. For this reason, TURN urges the Commission to focus on the RIM test for purposes of determining whether the costs and benefits of the tariff to all customers are equal. The RIM test compares the benefits of the tariff to all customers (excluding benefits that accrue only to NEM participants) with the costs of the tariff to all customers (including IOU incurred costs collected in rates and excluding the direct costs incurred by participants). The RIM test is therefore the only approach that accounts for the impact of NEM tariff design on all customers.

For these reasons, TURN believes that its tariff proposal directly responds to the statutory guidance and should be found to fully comply with this section.

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[56] The relevance of the TRC is addressed in Section IV.
[57] The only notable impacts on TRC values occur if NEM customers are assumed to bear additional up-front system costs tied to a second meter, interconnection or paying for estimated production calculation.

2827.1(b)(5) Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements.

TURN has not proposed any differential treatment of systems larger than 1 MW under its tariff and assumes in its model that all systems are sized to provide 100% of a customer's first year load. TURN's proposal therefore satisfies this statutory requirement.

2827.1(b)(6) Establish a transition period during which eligible customer-generators taking service under a net energy metering tariff or contract prior to July 1, 2017, or until the electrical corporation reaches its net energy metering program limit pursuant to subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827, whichever is earlier, shall be eligible to continue service under the previously applicable net energy metering tariff for a length of time to be determined by the commission by March 31, 2014. Any rules adopted by the commission shall consider a reasonable expected payback period based on the year the customer initially took service under the tariff or contract authorized by Section 2827.

Consistent with the requirements of §2827.1(b)(6), the Commission adopted a 20-yerar transition period for eligible NEM 1.0 customers in D.14-03-041. TURN does not propose to require existing NEM 1.0 customers to migrate to the new successor tariff at any point prior to the end of the 20-year transition period. However, TURN is proposing that a portion of the costs of the MTC be collected from existing non-CARE NEM 1.0 and 2.0 customers through a new surcharge set at a monthly fixed amount per customer.[58] The total amount of funds to be collected from legacy NEM customers

[58] TURN would exempt CARE customers taking service under NEM 1.0 or NEM 2.0 tariffs from paying this surcharge.

would be a function of the total MTC costs and the percentage of these costs to be collected from existing NEM customers.

If the Commission concludes that such a charge would infringe upon the adopted transition period for non-CARE NEM 1.0 customers, it can modify the original decision pursuant to Public Utilities Code §1708 so long as proper notice is given and an opportunity to be heard is provided to the parties.[59] The Commission has previously held that it may modify a prior decision if new facts are brought to its attention, conditions have undergone a material change or the Commission proceeded on a basic misconception of law or fact.[60] TURN submits that these conditions could be satisfied by the rapidly escalating cost shift resulting from NEM, the overall decline in residential retail sales tied to NEM subscriptions, and accelerating increases in utility rates due to factors that could not have been known (or predicted) at the time that D.14-03-041 was adopted.[61]

> *2827.1(b)(7) The commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding. Any fixed charges for residential customer generators that differ from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electrical corporation. The commission shall ensure customer generators are provided electric service at rates that are just and reasonable.*

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[59] Cal. Pub. Util. Code §1708 (The commission may at any time, upon notice to the parties, and with opportunity to be heard as provided in the case of complaints, rescind, alter, or amend any order or decision made by it. Any order rescinding, altering, or amending a prior order or decision shall, when served upon the parties, have the same effect as an original order or decision.)

[60] D.97-04-049, 1997 Cal. PUC LEXIS 427, *17.

[61] To the extent that the Commission finds the 20-year transition period is no longer needed for non-CARE NEM 1.0 customers to achieve payback, and the proposed surcharge would not infringe upon the achievement of payback over that period, it would be reasonable to modify D.14-03-041 to permit the imposition of a modest surcharge to cover a portion of the costs of the MTC for new low-income NEM customers.

The NEM successor tariff reforms are being considered as part of a rulemaking that involves all of the large electrical corporations defined by §2827(b)(5) that were required to make NEM tariffs available to their customers and implemented the successor tariff adopted in D.16-01-044. As a result, the reforms proposed by TURN and other parties may be considered in this proceeding.

2. *Principle #2 -- A successor to the net energy metering tariff should ensure equity among customers*

TURN's tariff proposal satisfies the goal of ensuring equity among customers in several respects. In D.21-02-007, the Commission declined to adopt a definition of "equity" in the context of this principle. TURN previously argued that achieving equity among customers involves the following:[62]

- Ensuring equal collection of unavoidable and nonbypassable charges from participating and non-participating customers.

- Ensuring all NEM customers pay a fair share for the grid services they use.

- Ensuring equal compensation for similar generation (i.e., similarly situated generation with the same output profile).

Many of TURN's stated equity objectives are reflected in other guiding principles and the statutory direction provided in Public Utilities Code §2827.1. TURN's proposal is expressly designed to create a base tariff that ensures equity by compensating participating customers fairly for the value they provide to all other customers and ensuring that the choice to install BTM resources by one customer does not shift shared costs to non-participating customers. This outcome is achieved by linking generation

[62] TURN opening comments on Proposed Guiding Principles for a Successor to the Net Energy Metering Tariff, R.20-08-020, December 4, 2020, page 4.

output to avoided costs and charging participants for their share of cost obligations that are unaffected by the decision to install BTM resources.

Moreover, TURN's proposal would treat customers equally regardless of their household income by providing bill savings based only on the value of the output from a BTM resource. Current NEM places a higher value on the output of a BTM resource serving a non-CARE customer as compared to a CARE customer. Remedying the existing economic discrimination embedded in NEM rate design is necessary to enable the accelerated adoption of behind the meter resources by CARE eligible households.

TURN's proposal would create a tariff that fully satisfies these equity objectives and addresses barriers to adoption with an up-front MTC. Although there are few good options for funding the MTC outside of rates in the short-term, the Commission can and should work with other state agencies and the Legislature to identify other sources of funds to limit or eliminate the impact of the MTC on rates, a result that would fully satisfy the goal of equity amongst customers. To start down this path, the Commission first must adopt a tariff that isolates the subsidies embedded into current NEM policy so that alternative funding sources can be pursued over time.

3. ***Principle #3 -- A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services***

Although TURN's tariff proposal does not specifically include new consumer protection elements, two key features would enhance existing measures by promoting transparency and enhancing the certainty of expected payback for new solar investments. First, TURN's tariff would allow all successor tariff subscribers to opt for a 5 or 10 year export rate locked to the most recently adopted ACC hourly values for the entire period. This option would provide certainty with respect to the compensation to be received for exports over the relevant timeframe. By contrast, NEM 2.0 customers have no reasonable method of locking in the value of export compensation over a similar timeframe. Second, TURN's proposal would provide CARE customers with an

MTC buydown calibrated to ensure, in combination with the tariff compensation and bill savings, that the costs of a new solar installation are recovered at the end of 10 years.

In D.20-08-001, the Commission adopted standardized inputs and assumptions for calculating electric utility bill savings from residential solar systems. These bill savings calculations rely on NEM 2.0 tariff design, assume escalation of utility rates over time and do not consider how changes to rate design, including the design of TOU periods and rate differentials across TOU periods, could affect a customer's bill savings. As a result, the standardized inputs do not produce a calculation that offers meaningful certainty to a customer participating in NEM 2.0. TURN's tariff would materially improve the certainty of the bill savings assumptions and assist customers with making informed choices when considering offers from vendors and installers. This outcome promotes consumer protection by allowing customers to more transparently compare options with greater certainty that bill savings benefits promised by vendors will actually be realized.

4. ***Principle #4 -- A successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1***

TURN's tariff proposal would treat all eligible technologies fairly. Although TURN's model only considers solar and storage resources, the tariff design is suitable for all eligible renewable generating technologies. Since export compensation would be based on the ACC and actual recorded market prices, any eligible resource would be treated identically with respect to the value of exported energy in a given hour. Similarly, any energy used to serve onsite loads would result in equivalent bill savings regardless of the type of eligible generating unit.

With respect to the MTC, the Commission should adapt TURN's modeling approach to incorporate assumptions regarding the ownership and operating costs of non-solar renewable generating resources. These assumptions would be critical to determining the appropriate level of an MTC needed to achieve a target payback period. TURN recommends using the same payback periods for all eligible technologies and would only vary the duration based on the type of customer (CARE vs. Non-CARE).

5. ***Principle #5 -- A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeón), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18***

TURN's tariff would ensure that NEM policy is properly coordinated with state energy policies implemented by the CPUC and other agencies as described in the following paragraphs.

Senate Bill 100 (DeLeón)

Pursuant to SB100, it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and state agencies by December 31, 2045. SB 100 does not assign priority to any particular technology or to resources located behind a customer's meter. The controlling statutory provisions also direct the Commission to "ensure that actions taken in furtherance of" the 100 percent objective "prevent unreasonable impacts to electricity, gas, and water customer rates and bills resulting from implementation of this section, taking into full consideration the economic and environmental costs and benefits of renewable energy and zero-carbon resources."[63] This provision should be understood to prioritize least-cost carbon reduction strategies that produce highest environmental value.

There is no evidence to support the notion that the existing NEM tariff satisfies this principle. Absent major reforms, the increasing cost shifting associated with the deployment of substantial additional BTM resources will lead to

[63] Cal. Pub. Util. Code §454.53(b)(2).

unreasonable impacts to electricity rates that could be avoided without compromising progress to a carbon-free grid. These impacts would hamper the state's ability to deploy (and fairly recover) investments needed to achieve the 100% target. TURN's tariff would promote cost-effective expenditures on new zero carbon electric generation and limit subsidies to those needed to achieve specifically defined equity goals. Moreover, TURN's proposal would ensure that all customers are responsible for sharing the cost of major investments in the electrical grid to meet these ambitious decarbonization objectives.

Integrated Resource Planning Process

The Integrated Resource Planning Process does not currently consider or quantify the costs of BTM resources in its planning assumptions. Since future BTM deployment projections represent a hard-wired input into the Reference System Plan, the IRP modeling does not consider BTM solar as a candidate resource subject to any type of cost-effectiveness analysis. TURN's tariff proposal would address this omission by explicitly identifying the up-front incentives needed to achieve specific payback periods for BTM resources.

If TURN's approach is approved, the Commission could assess the incremental costs needed to deploy NEM resources in IRP modeling with results used to inform the development of an optimal and least-cost resource portfolio. To the extent that the IRP modeling finds benefits from shorter BTM resource payback periods, this information could be used to support changes to the MTC structure. Absent this type of NEM reform, there is no clear way to identify BTM resource subsidies and compare them to alternative IRP-driven investments.

Title 24 Building Energy Efficiency Standards

The Title 24 standards require new residential buildings to include a solar PV system capable of serving a portion the building's load unless the home has shading or the builders opt for additional energy efficiency, storage or other options to reduce solar panel requirements. Given the fact that these standards require compliance by the builder, TURN would not provide an MTC for Title 24 new buildings. If an MTC is authorized for these buildings, the Commission should consider relying on different payback assumptions including a lower installation cost due to the efficiency of incorporating BTM resources into new construction.

There is no reason to conclude that changes in NEM tariffs are adverse to the Title 24 requirements. In the process of considering the new rules, the California Energy Commission (CEC) found that the Title 24 solar mandate would remain cost effective under a range of future NEM tariff reform scenarios.[64] By making any subsidies transparent, TURN's proposal would enable the CEC to evaluate the cost-effectiveness of Title 24 rules over time and determine whether additional refinements to the policy are appropriate in light of the costs and benefits to new homeowners and the entire electrical system.

California Executive Order B-55-18

In signing Executive Order B-55-18, Governor Jerry Brown committed the state to achieve carbon neutrality no later than 2045. Although the CPUC is not expressly referenced, the Executive Order does call for all programs carried out to achieve carbon neutrality to "seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities."[65] TURN's tariff proposal places primary focus on the deployment of BTM resources by CARE customers and offers an approach to prioritizing deployment in Disadvantaged Communities by calibrating the MTC incentive to achieve a reasonable payback period for specific customer

[64] https://ww2.energy.ca.gov/title24/2019standards/documents/Title24_2019_Standards_detailed_faq.pdf

[65] Executive Order B-55-18, Ordering Paragraph 5.

subgroups. Moreover, TURN's proposal would slow the pace of future electricity rate hikes that are paid by nonparticipating low-income customers and lead to more affordable bills. Unlike current NEM policy, which provides the largest incentives to wealthier customers, TURN's approach is directly responsive to the goal of promoting economic resiliency and improved air quality in low-income communities.

6. ***Principle #6 -- A successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities***

TURN's proposal would be transparent in several key respects. First, the level of any MTC incentives would be known prior to the customer making a decision to invest in a new BTM system. By contrast, the level of compensation to be realized under current NEM is difficult, if not impossible, for prospective NEM customers to accurately assess or take into account when considering a new investment or contractual commitment. Second, the method of calculating responsibility for NUS costs would be tied to actual consumption by the individual customer and shown clearly on each bill. Third, the value of exports would be based on the ACC values for non-energy supply and on actual market prices for the energy supply components. As a result, there should be little mystery as to how bills are calculated and the basis for the exact value provided to a participating customer for the operation of their generating resource.

The uniformity of TURN's proposal across utilities is based on the use of a single approach to calculating avoided costs (ACC and CAISO prices) that takes into account geography and market conditions but does not vary unreasonably by utility. By contrast, existing NEM tariffs provide far greater compensation to customers of SDG&E than SCE simply by virtue of SDG&E's higher average retail rates. The current approach is not uniform and results in unequal value provided to customers based solely on the average retail rates in their region.

7. ***Principle #7 -- A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system***

TURN's proposal is designed to establish transparent incentives for customers to maximize the value of their BTM resources in a manner that also benefits all customers. TURN would set export compensation at the ACC values for components other than energy supply and use actual hourly CAISO market prices for energy supply components. Both the ACC values and CAISO market prices are time-differentiated. As a result, TURN's tariff would motivate customers to maximize the economic value of their BTM resource production by aligning output, to the maximum extent possible, with periods of higher hourly ACC and CAISO prices.

For example, customers would be motivated to undertake demand response, load shifting and conservation during peak hourly price periods to maximize the amount of production that can be exported and receive premium value. This behavior would benefit all customers by incentivizing incremental supply during periods of scarcity and peak pricing. Similarly, providing a generation rate credit for production serving onsite load would motivate NEM customers to self-supply during periods when the TOU generation rate component is at its highest level, thereby realizing the greatest benefits to themselves and the system.

8. ***Principle #8 -- A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.***

TURN's tariff proposal would be neutral amongst retail providers of electricity service, preclude cross-subsidization, and avoid any embedded incentives that motivate a participating customer to either remain with the incumbent utility or switch to alternative Load Serving Entities (LSEs). Because export credits would include both energy supply and non-energy supply components, participating customers taking service from non-IOU LSEs would receive export credits from two sources. For the ACC values not related to energy supply, the export credit would be provided by the IOU (since these values relate to elements of distribution service paid by both bundled and departing load customers). For ACC values relating to energy supply, the export credit would be paid by the IOU only to its bundled customers. NEM customers served by non-IOU LSEs would receive energy supply export credits from their retail provider. This treatment preserves the obligation of each LSE to provide energy supply and generation services to their customers.

Because participating customers on bundled utility service would receive a generation rate credit for BTM production used for self-consumption, there would be no cross-subsidization from other rate components. Participating customers served by non-IOU LSEs are not charged an IOU generation rate and would therefore receive these credits from their retail provider. This approach would permit CCAs and Direct Access providers to provide the same, or different, generation credit levels than the IOUs. The choice to provide different generation-related compensation would be made entirely by the CCA or DA provider with any associated costs being born entirely be their customers.

Up-front MTC incentives would be available to all eligible customers regardless of whether they take bundled service or are served by a CCA or DA provider. To the extent that MTC costs are collected from non-rate sources, there would be no impact on customers of any LSE. The collection of any MTC costs in rates would occur through the nonbypassable PPP charge applicable to both bundled and departing load customers, thereby ensuring that these costs are recovered in a competitively neutral manner.

B. TURN's proposal would not have any tax implications for customers

There are no tax implications for customers under TURN's proposal to change the export credit from a modified retail rate (under NEM 2.0) to an avoided cost rate. Providing a bill credit based on export compensation that differs from the retail rate does not materially change the structure of the tariff in a manner that triggers adverse tax consequences. Current state law permits customers with certain onsite renewable generation to receive a generation rate credit for "co-energy metering" and authorizes customers with onsite solar to receive an avoided cost rate for net surplus electricity generation.[66] So long the net metering credit will generally not offset more than the amounts a customer owes the utility for electricity service, the IRS has found that the arrangement does not constitute a sale of electricity.[67] The value of the export credit is not a dispositive or even informative attribute when determining whether the tariff constitutes a valid netting arrangement under IRS rules.

TURN's proposal would allow a NEM customer to receive cash out monetary compensation only in the event of excess generation over the course of a 12-month period in a manner consistent with the Net Surplus Compensation treatment pursuant to Public Utilities Code §2827(h)(5). There has been no finding to date that any of these existing arrangements jeopardize the customer's ability to take advantage of the investment tax credit or create other adverse tax consequences.

C. TURN's proposal for collecting Public Purpose Costs does not violate §381

Pursuant to §381 of the Public Utilities Code, the Commission is required to approve the collection of Public Purpose Program (PPP) costs as "a nonbypassable element of the local distribution service and collected on the basis of usage."[68] The costs subject to this requirement include energy efficiency, the CARE program, and research and development (including the EPIC program).[69] TURN's proposal is consistent with this requirement because all nonbypassable charges, including the cost categories referenced in §381, would be collected on the basis of a customer's entire usage including self-consumption.

TURN's proposal would collect PPP costs associated with participating customer imports using existing consumption rates applied to all customers on the same tariff

[66] Cal. Pub. Util. Code §2827(h)(5), §2827.10
[67] For example, see IRS Private Letter Ruling 201536017, Release Date: 9/4/2015.
[68] Cal. Pub. Util. Code §381(a)
[69] D.11-12-035, page 32 (The Commission directed EPIC costs to be recovered as part of the PPP rate component).

without BTM resources. The NUS charge would collect additional PPP costs associated with self-consumption by calculating the portion of a customer's actual monthly consumption supplied by BTM resources. Because the amount of costs collected from each customer via the NUS charge would vary based on actual (or estimated) self-consumption in each month, they would not be fixed for any NEM customer. The resulting charge is based entirely on customer usage.

Moreover, §2827.1(b) directs the Commission to develop a successor tariff "notwithstanding any other law". This phrasing suggests that the requirements of §381 are not be applicable for purposes of designing a successor tariff that satisfies the other requirements of §2827.1. The Commission may conclude that the §381 limitation is not binding only for purposes of the NEM successor tariff.

D. Compliance with the Public Utility Regulatory Policies Act

TURN's tariff proposal retains the structure and approach that is the basis for net metering's exemption from federal regulation under the Public Utility Regulatory Policies Act (PURPA). Changing the compensation rate to an avoided cost export credit does not change the net billing arrangement that exists under the current net metering model and therefore does not create a "sale" that would be treated by the Federal Energy Regulatory Commission (FERC) as a wholesale transaction.

In rejecting a challenge to net metering by MidAmerican Energy, FERC concluded "no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting."[70] FERC has reaffirmed this holding in subsequent decisions and state commissions have relied upon these precedents to design net metering tariffs that provide retail rate credits for production during a billing period.[71] The Commission

[70] Midwestern Energy Co., 94 FERC ¶61, 340 (2001)
[71] Sun Edison LLC, 129 FERC ¶61, 146 (2009).

previously agreed that "FERC has held that a net billing arrangement is not subject to FERC jurisdiction so long as no "net sale" is made to the utility."[72]

Under both existing NEM and TURN's proposal, excess credits accumulated over a billing period may not be paid out to a customer in cash. California already allows NEM customers to carry forward any surplus balance for 12 calendar months. Any credit balances that remain after 12 months are zeroed out if there is no excess production on a kWh basis.[73] If the customer has net surplus production (on a kWh basis) over a 12-month period, they are eligible for compensation based on the value of the electricity and the value of any renewable attributes provided to the utility.[74] This approach, authorized by AB 920 (Huffman, 2009) is consistent with the PURPA requirements governing the pricing of energy purchased from cogenerators and other "qualified facilities." TURN's proposal would not alter this approach.

VI. IMPLEMENTATION ISSUES AND TIMELINES

As requested in the January 28 ALJ Ruling, this section identifies the implementation plans and timelines associated with TURN's tariff proposal.[75] TURN does anticipate the need for a further formal implementation phase within this proceeding that would resolve a variety of remaining issues. Depending upon whether the Commission adopts TURN's proposal in whole, or in part, the following issues would need to be resolved in a second phase of this proceeding:

- Approval of inputs to methodology for calculating and updating the Market Transition Credit based on a defined target payback period. Relevant inputs

[72] D.11-06-016, page 9.
[73] Many existing NEM customers have surplus bill credits that are not attributable to excess production over a 12-month period. This is due to the fact that customers on time of use rates receive bill credits based on the timing of solar production exported to the grid. Excess production during peak periods can generate bill credits that exceed the rate charges for consumption of a similar quantity of energy during off-peak hours.
[74] Cal. Pub. Util. Code §2827(h)(5).
[75] ALJ January 28 Ruling, Instruction #4.

include assumed installed generation cost, forecasted bill savings, discount rate, and other key variables.

• Clarifications to the methodology for calculating Nonbypassable, Unavoidable and Shared costs to be collected from NEM customers for self-consumption quantities.[76]

• Rules governing the calculation of estimated production from BTM generation for purposes of calculating self-consumption quantities assessed NUS costs.

• Approval of cost recovery for MTC costs and consideration of non-rate options for financing MTC incentives over time.

• Approval of export credit methodology that relies on ACC values and CAISO hourly market prices.

• Establishment of technical requirements for paired storage units to dispatch in response to system emergencies and severe stress conditions.

If the Commission provides clear and decisive guidance through a final decision in this phase, TURN anticipates that these open issues could be primarily resolved through a collaborative process that involves working groups.[77] These working groups would be composed of key stakeholders and produce a report that addresses recommended implementation details. This report would be subject to comment by all parties.

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[76] These clarifications would be necessary if the Commission finds that some, but not all, portions of transmission and distribution costs should be assigned to self-consumption quantities.

[77] If the Commission declines to provide clear guidance, and instead leaves disputed factual or policy issues unresolved, a second phase may require more formal process to develop an evidentiary record.

Following comments, the Commission would issue a Decision resolving all remaining issues.

A possible timeline for this process is as follows:

Working group discussions	*+ 60-90 days*
Working group report produced	*+ 30 days*
Opening/reply comments on working group report	*+ 30 days*
Proposed decision	*+ 60 days*
Final Commission decision	*+ 30 days*
Total time for resolution	*+ 210-240 days*

This timeline assumes that the Commission adopts TURN's proposal without major modifications that require additional fact-finding or litigation relating to threshold tariff design issues. It is not possible to provide a schedule of subsequent implementation activities if the Commission adopts a hybrid of multiple tariff proposals, requires additional work on the development of methodologies relating to NUS costs or Export Credits, or seeks to incorporate other tariff elements that are not fully fleshed out.

VII. CONCLUSION

TURN urges the Commission to adopt reforms to the existing successor tariff in a manner that fairly balances the interests of participants and non-participants. For the reasons described in previous sections, TURN's proposal satisfies these objectives and would allow for a long overdue course correction. This correction would support long-term affordability goals for all customers and ensure that subsidies for BTM resource deployment are transparent, targeted to those with the greatest needs, and sourced to the greatest extent possible from funding outside of retail rates.

Respectfully submitted,

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Appendix A
DESCRIPTION OF TURN MODEL

Introduction

TURN developed its own cost and tariff model for use in this proceeding. The model is in Excel format, contains transparent input assumptions that may be modified by users, and is available for download and use by all parties via the following download link:

https://tinyurl.com/TURN-NEMmodel

TURN has requested an opportunity to separately present on the model at the March 23-24 workshop.

Overview

The goal of the TURN Model is to calculate the Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant Cost Test (PCT) and Program Administrator Cost (PAC) test and discounted payback period results for a given Utility, Customer, Distributed Energy Resource (DER) Type, and Successor Tariff (ST) characterization, with the goal of designing a ST that conforms to Guiding Principles. These characterization dimensions are described in detail in the following sections.

General

The model produces results for bundled residential customers of PG&E, SCE and SDG&E. All costs and revenues are presented in nominal dollars. Customer loads, generation, rates and avoided costs are modeled in month-hour weekday-weekend granularity. Holidays were not allocated exclusively to weekends. The TURN Model assumes a 20-year analysis horizon and contains no adoption logic.

Avoided costs (AC) were sourced from the 2020 ACC Electric Model v1c. An error in the calculator affecting distribution costs was corrected (Distribution!$AQ was being used for all scenarios in the Distribution Capacity block on the Detailed Output tab). The model currently contains customer loads for PG&E only, however once the model is fully populated, customer loads will also be modeled for SCE and SDG&E. Customer load shapes prior to DER adoption are differentiated by IOU, CARE / non-CARE, Dual Fuel / All Electric, Inland / Coastal baseline region, EV / non-EV, and Large / Small usage (kWh) size. There are up to 32 load shapes for each utility. Load shapes for a given combination may not be available due to utility data confidentiality issues. Only one active customer can be modeled at a time.

Customer generation profiles were sourced from the National Renewable Energy Laboratory's (NREL) PVWatts tool for an Inland and a Coastal location for each utility.

Extant rates for each utility can be specified for up to 3 Time of Use (TOU) periods on weekdays and weekends. For extant rates that include baselines, these are specified for dual-fuel and all-electric customers in an inland and a coastal region. Nonbypassable Charges (NBCs) are specified per extant rates, however future NBCs that will be applicable to bundled customers, such as the Power Cost Indifference Adjustment (PCIA), may also be entered. TURN's ST proposal assumes that the current PCIA charge is collected as a NBC, and that generation rates are reduced commensurately.

Distributed Energy Resource (DER) Type

The model includes a DER costing pro forma. The analysis horizon is 20 years. Arrays cannot be sized larger than load. Installations can be modeled for the following years: 2022, 2023, 2024, 2025.

Standalone solar PV and paired storage technologies can be modeled. Solar PV is sized as a share of usage (kWh) and can be up to 100% of usage in the first year. This is accomplished via an input multiplier that scales generation pro rata in all hours.

The generation profile corresponds to the selected utility and location (coastal or inland). TURN's Proposal assumes a 0.7% degradation rate, per the Q1 2020 NREL Cost Benchmark study. Solar PV degradation commences in year 2.

Incremental interconnection fees and utility-borne interconnection cost values were gathered from the NEM 2.0 Lookback Study. In addition to these fees, TURN's Proposal assumes a $900 customer-borne second meter cost or a $100 customer-borne upfront cost for estimating generation. Utility-borne billing costs in the estimated generation scenario are assumed to be $50 per year. In the model, the estimated generation is assumed identical to metered output.

Incentives such as those provided under the Self-Generation Incentive Program and Multifamily Affordable Solar Housing Program may be applied, where appropriate.

TURN's Proposal employs NREL's Q1 2020 Solar PV System Cost Benchmark for residential systems for solar PV systems operational in 2022 ($2.71 per Watt-dc). TURN's Proposal did not examine a storage scenario. TURN's Proposal assumes that capital costs escalate at 1.5% to the operations year, and assumes a 1.15 ILR. Inverter replacement is assumed to cost $0.20 per Watt-ac. Annual insurance cost is assumed to be 1% of Capital Expenditures.

Finance assumptions vary per CARE, Non-CARE and Multi-family ownership and for leased and upfront purchases. In TURN's Proposal, both CARE and non-CARE customers were assumed to lease systems with a 60% equity share, a 5% cost of debt and an 9% nominal cost of equity[78]. The federal and state income tax rates for leased systems are 21% and 8.8%, respectively. TURN's model enables the user to enter an assumption regarding whether the system is financed via an upfront purchase or

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[78] https://www.nrel.gov/docs/fy19osti/72399.pdf, p. 22.

leasing. Results accompanying this proposal show a leasing scenario. TURN's Model assumes the federal and state income tax rates for the upfront purchase scenario are 24% and 9.3%, respectively. 5-yr MACRS depreciation is incorporated in leased system costs. ITC is assumed to be 26% in 2022, 22% in 2023, and 0% from 2024.

<u>Successor Tariff</u>

TURN's ST proposal presents results for PG&E. TURN's model provides inputs for retail rate escalation but does not dynamically calculate retail rates over time. The model assumes that retail rates are escalated per the February 2021 CPUC Rates En Banc Whitepaper values: 3.7% for PG&E, 3.5% for SCE, and 4.7% for SDG&E.[79]

Net energy metering (NEM) and net energy billing (NEB) can be modeled. Under NEM, exports are compensated per the specified ST. Under NEB, exports are compensated at AC. AC may be averaged over an input number of years (in order to provide a more stable price signal) or assessed annually. For a given ST, the analysis horizon is 20 years. For NEM, monthly netting or hourly netting can be modeled. TURN's Proposal assumes hourly netting. A baseline credit/charge mechanism can be activated. The results presented in the proposal do not assume the customer takes service under a tariff with a baseline quantity.

The distribution component of NUS charge revenues is calculated per self-consumption for the active customer in each TOU period times the corresponding ST distribution rates. The distribution component of the NUS charge may be assessed per $/kW-mo nameplate capacity (ac), a monthly customer charge, or a $/kWh rate that is assessed on self-consumption. TURN's model assumes the latter. An input enables the grid charge to be reduced on a percentage basis. The NBC component of the NUS Charge is also assessed on self-consumption. NBCs can be specified by component and have not been escalated.

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[79] En Banc Whitepaper, page 8.

Transition Period

There is no transition period: the ST assumed in place from 2022.

Minimum Bill

A minimum bill that differs from the extant rate can be specified.

Extant Rate Structure

Successor Tariff generation and distribution TOU rates may differ from the extant TOU rate structure. If the ST TOU rates differ from the extant structure, they are calculated such that in year one they are revenue neutral to extant structures by season. Applicable Avoided Cost can also be specified by component. The ST used to produce TURN's Proposal results did not differ from the extant TOU rate structure.

Buydown Incentive / Market Transition Credit

The Buydown Incentive can be calculated for an assumed benefit/cost ratio over an assumed discounted payback period (years). The buydown incentive is the incremental upfront amount that would be paid to customers in order to achieve the target present value benefit/present value cost ratio in the identified payback year. In TURN's Model, the Buydown Incentive calculation employs the participant discount rate is that used in the PCT. In TURN's Proposal, this is assumed to be 8%. Following the payback period, NEB or a buy-all / sell-all structure may be assumed. If NEB is assumed, export compensation can be at AC or Net Surplus Compensation (NSC). NSC is the average of avoided costs for GHG Cap and Trade and Energy ACC components from 8 am to 5 pm. If buy-all / sell-all is assumed, all generation may be compensated at AC or NSC. TURN's Proposal assumes export compensation at AC following the payback period.

The Buydown Incentive may be collected in rates or from an outside source. The share that is collected in rates is included in the RIM cost test. The model enables the Buydown Incentive to be applied in the TRC cost test, however TURN's results did not assume this treatment. TURN's results assume that 25% to 100% of the Buydown Incentive is included in RIM.

TURN's model assumes that Title 24 installations (new residential construction) are not eligible for a Buydown Incentive.

Calculation of payback year

TURN's Model provides a discounted payback year result. The payback year is the year when the present value of benefits first exceeds the present value of costs. Under a lease scenario, these costs are all incurred over a 20-year timeframe. Under an upfront purchase scenario, the present value calculation incorporates costs (including any tax benefits) incurred through the payback period. These costs include all Capex over a 20-year timeframe and O&M incurred through the payback date. TURN's proposal assumes the 8% participant discount rate for this calculation.

Storage

In TURN's model, storage is sized per assumed kW and duration (hours). TURN's ST Proposal did not evaluate storage. TURN's model allows users to enter the assumed storage capacity and duration, round trip efficiency (RTE), and an economic life and battery replacement cost expressed as a share of storage cost.

Storage is modeled with one charge/discharge cycle per day. Storage may only charge from the solar PV generator. Storage charges until battery is full and discharges daily starting at the beginning of the daily "peak" period. If storage is over-sized relative to load, it may not be able to discharge fully.

Data remaining to be added to the model

Only PG&E can currently be fully characterized in TURN's model. The following information will be incorporated in the model as soon as possible so that results can be presented for PG&E, SCE, and SDG&E in direct testimony.

- Bundled pre-adoption residential customer load profiles for SCE and SDG&E;
- CARE and non-CARE annual bundled revenue requirement, usage (kWh) and customer numbers to ensure revenue neutral rate calculations;
- SDG&E bundled residential class load shape;
- SDG&E inland and coastal ACC by month-hour; and
- Extant SDG&E rates (with and without baseline) and extant SCE rate (with baseline).

Appendix B

ADDITIONAL RESULTS FROM TURN MODEL FOR VARIOUS PG&E CUSTOMER TYPES AND MODEL DASHBOARD FOR SCENARIO #4

Scenario	PG&E CARE Dual Fuel Coastal	PG&E CARE Dual Fuel Inland	PG&E CARE All Electric Coastal	PG&E CARE All Electric Inland
COMMON ASSUMPTIONS: 2022 INSTALL YEAR, ACC FLOATS, NO BASELINE FOR EXTANT & ST, LEASED, PCIA & TX in NUS, ESTIMATED CONSUMPTION, GEN SIZED TO LOAD				
EXISTING NEM 2.0				
20-yr Cost Test Results				
RIM	**0.725**	**0.642**	**0.753**	**0.660**
PCT	**1.196**	**1.191**	**1.150**	**1.159**
TRC	**0.871**	**0.772**	**0.862**	**0.766**
PAC	**15.736**	**24.534**	**12.967**	**19.570**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	15	15	16	15
Discounted Payback Years - after buydown	n/a	n/a	n/a	n/a
Year 1 NUS $/kWh	-	-	-	-
Year 1 NUS Monthly Charge ($)	$ -	$ -	$ -	$ -
Year 1 NUS Monthly Usage (kWh)	199	335	169	263
Upfront Capex Buydown $	n/a	n/a	n/a	n/a
Upfront Capex Buydown $/kW	n/a	n/a	n/a	n/a
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ -	$ -	$ -	$ -
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ -	$ -	$ -	$ -
Annual Self-consumption kWh	2,389	4,024	2,025	3,152
NO BUYDOWN				
20-yr Cost Test Results				
RIM	**1.146**	**1.224**	**1.120**	**1.191**
PCT	**0.764**	**0.692**	**0.756**	**0.691**
TRC	**0.810**	**0.740**	**0.791**	**0.728**
PAC	**6.456**	**10.015**	**5.336**	**8.007**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	n/a	n/a	n/a	n/a
Year 1 NUS $/kWh	0.127	0.129	0.126	0.128
Year 1 NUS Monthly Charge ($)	$ 25.26	$ 43.22	$ 21.33	$ 33.55
Year 1 NUS Monthly Usage (kWh)	199	335	169	263
Upfront Capex Buydown $	n/a	n/a	n/a	n/a
Upfront Capex Buydown $/kW	n/a	n/a	n/a	n/a
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ -	$ -	$ -	$ -
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ -	$ -	$ -	$ -
Annual Self-consumption kWh	2,389	4,024	2,025	3,152
WITH BUYDOWN: 1.0 PAYBACK AT YEAR 10 - 100% BUYDOWN IN RIM				
20-yr Cost Test Results				
RIM	**0.666**	**0.623**	**0.655**	**0.614**
PCT	**1.229**	**1.195**	**1.225**	**1.195**
TRC	**0.810**	**0.740**	**0.791**	**0.728**
PAC	**6.456**	**10.015**	**5.336**	**8.007**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	10	10	10	10
Year 1 NUS $/kWh	$ 0.127	$ 0.129	$ 0.126	$ 0.128
Year 1 NUS Monthly Charge ($)	$ 25.26	$ 43.22	$ 21.33	$ 33.55
Year 1 NUS Monthly Usage (kWh)	199	335	169	263
Upfront Capex Buydown $	$ 4,653	$ 9,051	$ 3,870	$ 7,225
Upfront Capex Buydown $/kW	$ 1,522	$ 1,629	$ 1,544	$ 1,636
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ 10.79	$ 20.99	$ 8.97	$ 16.75
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ 21.58	$ 41.98	$ 17.95	$ 33.51
Annual Self-consumption kWh	2,389	4,024	2,025	3,152

Scenario	PG&E CARE Dual Fuel Coastal	PG&E CARE Dual Fuel Inland	PG&E CARE All Electric Coastal	PG&E CARE All Electric Inland
WITH BUYDOWN: 1.0 PAYBACK AT YEAR 15 - 25% BUYDOWN IN RIM				
20-yr Cost Test Results				
RIM	**1.011**	**1.027**	**0.989**	**1.004**
PCT	**1.107**	**1.091**	**1.105**	**1.091**
TRC	**0.810**	**0.740**	**0.791**	**0.728**
PAC	**6.456**	**10.015**	**5.336**	**8.007**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	15	15	15	15
Year 1 NUS $/kWh	$ 0.127	$ 0.129	$ 0.126	$ 0.128
Year 1 NUS Monthly Charge ($)	$ 25.26	$ 43.22	$ 21.33	$ 33.55
Year 1 NUS Monthly Usage (kWh)	199	335	169	263
Upfront Capex Buydown $	$ 3,434	$ 7,188	$ 2,882	$ 5,740
Upfront Capex Buydown $/kW	$ 1,124	$ 1,294	$ 1,150	$ 1,300
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ 7.96	$ 16.67	$ 6.68	$ 13.31
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ 15.93	$ 33.34	$ 13.37	$ 26.62
Annual Self-consumption kWh	2,389	4,024	2,025	3,152

Scenario	PG&E Non-CARE Dual Fuel Coastal Large No EV	PG&E Non-CARE Dual Fuel Inland Small No EV	PG&E Non-CARE All Electric Coastal small No EV	PG&E Non-CARE All Electric Inland Small No EV
COMMON ASSUMPTIONS: 2022 INSTALL YEAR, ACC FLOATS, NO BASELINE FOR EXTANT & ST, LEASED, PCIA & TX in NUS, ESTIMATED CONSUMPTION, GEN SIZED TO LOAD				
EXISTING NEM 2.0				
20-yr Cost Test Results				
RIM	**0.434**	**0.411**	**0.459**	**0.418**
PCT	**1.893**	**1.733**	**1.769**	**1.705**
TRC	**0.903**	**0.763**	**0.866**	**0.764**
PAC	**51.651**	**16.934**	**14.035**	**17.615**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	7	8	8	8
Discounted Payback Years - after buydown	n/a	n/a	n/a	n/a
Year 1 NUS $/kWh	-	-	-	-
Year 1 NUS Monthly Charge ($)	$ -	$ -	$ -	$ -
Year 1 NUS Monthly Usage (kWh)	658	237	179	239
Upfront Capex Buydown $	n/a	n/a	n/a	n/a
Upfront Capex Buydown $/kW	n/a	n/a	n/a	n/a
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ -	$ -	$ -	$ -
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ -	$ -	$ -	$ -
Annual Self-consumption kWh	7,897	2,841	2,151	2,866
NO BUYDOWN				
20-yr Cost Test Results				
RIM	**1.120**	**1.024**	**1.013**	**1.033**
PCT	**0.852**	**0.766**	**0.834**	**0.764**
TRC	**0.881**	**0.719**	**0.799**	**0.722**
PAC	**20.985**	**6.941**	**5.768**	**7.216**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	n/a	n/a	n/a	n/a
Year 1 NUS $/kWh	$ 0.211	$ 0.212	$ 0.209	$ 0.210
Year 1 NUS Monthly Charge ($)	$ 138.87	$ 50.24	$ 37.45	$ 50.21
Year 1 NUS Monthly Usage (kWh)	658	237	179	239
Upfront Capex Buydown $	n/a	n/a	n/a	n/a
Upfront Capex Buydown $/kW	n/a	n/a	n/a	n/a
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ -	$ -	$ -	$ -
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ -	$ -	$ -	$ -
Self-consumption kWh	7,897	2,841	2,151	2,866
WITH BUYDOWN: 1.0 PAYBACK AT YEAR 10 - 100% BUYDOWN IN RIM				
20-yr Cost Test Results				
RIM	**0.687**	**0.591**	**0.642**	**0.593**
PCT	**1.265**	**1.224**	**1.256**	**1.224**
TRC	**0.881**	**0.719**	**0.799**	**0.722**
PAC	**20.985**	**6.941**	**5.768**	**7.216**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	10	10	10	10
Year 1 NUS $/kWh	$ 0.211	$ 0.212	$ 0.209	$ 0.210
Year 1 NUS Monthly Charge ($)	$ 138.87	$ 50.24	$ 37.45	$ 50.21
Year 1 NUS Monthly Usage (kWh)	658	237	179	239
Upfront Capex Buydown $	$ 13,503	$ 5,687	$ 3,769	$ 5,940
Upfront Capex Buydown $/kW	$ 1,327	$ 1,492	$ 1,386	$ 1,497
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share	$ 31.31	$ 13.19	$ 8.74	$ 13.77
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share	$ 62.62	$ 26.37	$ 17.48	$ 27.55
Self-consumption kWh	7,897	2,841	2,151	2,866

Scenario	PG&E Non-CARE Dual Fuel Coastal Large No EV	PG&E Non-CARE Dual Fuel Inland Small No EV	PG&E Non-CARE All Electric Coastal small No EV	PG&E Non-CARE All Electric Inland Small No EV
WITH BUYDOWN: 1.0 PAYBACK AT YEAR 15 - 25% OF BUYDOWN IN RIM				
20-yr Cost Test Results				
RIM	**1.015**	**0.902**	**0.923**	**0.908**
PCT	**1.123**	**1.104**	**1.119**	**1.104**
TRC	**0.881**	**0.719**	**0.799**	**0.722**
PAC	**20.985**	**6.941**	**5.768**	**7.216**
Discounted Payback Metrics				
Discounted Payback Years - prior to buydown	> 20 yrs	> 20 yrs	> 20 yrs	> 20 yrs
Discounted Payback Years - after buydown	15	15	15	15
Year 1 NUS $/kWh	$ 0.211	$ 0.212	$ 0.209	$ 0.210
Year 1 NUS Monthly Charge ($)	$ 138.87	$ 50.24	$ 37.45	$ 50.21
Year 1 NUS Monthly Usage (kWh)	658	237	179	239
Upfront Capex Buydown $	$ 8,871	$ 4,199	$ 2,545	$ 4,397
Upfront Capex Buydown $/kW	$ 872	$ 1,102	$ 936	$ 1,108
$/month Non-CARE NEM 1.0 & NEM 2.0 - 25% share of Buydown in RIM	$ 20.57	$ 9.74	$ 5.90	$ 10.20
$/month Non-CARE NEM 1.0 & NEM 2.0 - 50% share of Buydown in RIM	$ 41.14	$ 19.47	$ 11.80	$ 20.39
Self-consumption kWh	7,897	2,841	2,151	2,866

Model Dashboard Screenshot: PG&E Inland All-Electric CARE Customer - Scenario #4

Key Driver Inputs	Value
Discount Rates	
Active Participant	8.00%
Utility - PG&E	7.81%
Specification of Active Customer Load Shape	
Utility	PG&E
Customer Type (rates)	CARE
Location	Inland
All Electric or Dual-Fuel	All Electric
Size	Small
Electric Vehicle	No EV
Upfront Buydown Incentive	
Discounted Payback Period (years)	15
Ratio of PV Benefits to PV Costs ("Sustainable" over Payback Period)	1.0
Incentive Active Flag (1 = on; 0 =off)	1
If incentive, Buy-all / Sell-all Post-Payback Period (1=on, 0=off)	0
If BA/SA, compensation from year 16 (1 =Active ACC; 0 =NSC)	0
If Buydown & no BA/SA, exports comp from year 16 (1 =NSC; 0 =Active ACC)	0
Specification of Successor Tariff	
Baseline structure (1=with baseline, 0=no baseline)	0
Successor Tariff Scenario Selection	2
Minimum bill ($ per day)	$ 0.21371
Treatment for Exports (1= Net Billing, 0 = NEM2)	1
If net billing, 1= NBCs on consumption; 0 = NBCs on cons+ self-cons	0
If 0 selected above, NUS Costs Selection	0
0 = All NBCs Can Be Assessed on Self-Consumption	
1 = All NBCs Except PCIA Can Be Assessed on Self-Consumption	
2 = All NBCs Except PCIA & Transmission Can Be Assessed on Self-Consumption	
Share of Self-Consumption Distribution Costs Collected	100%
Collection of Above Charge (1=$/kW-mo PV, 2=$/cust-mo, 0=$/kWh self-cons)	0
NUS Distribution Charge for Self-Consumption ($/kW, $/month or $/kWh per se	$ 0.068
Year 1 Total NUS Charge ($/kWh self-consumption)	$ 0.128
Year 1 Monthly NUS Usage (kWh)	263
Year 1 Monthly NUS Charge ($/month)	$ 33.55
Monthly or Hourly Netting (1=monthly, 0=hourly)	0
Avoided Cost Compensation (Net Billing Scenario)	
Fixed Average or Varies Annual (1=fixed, 0=annual)	0
If Fixed, Term of Average Tranche (years)	10
Specification of Generator	
Active Technology Selection (storage activates CPP)	Solar PV
Customer Type (for finance costs)	CARE
Active Financing Type Selection	Lease
Generation Calculation (for incremental costs)	Estimated
% of First Year Load Served by Generator (<=100%)	100%
Storage SGIP Equity Adder (1=equity, 2=resiliency, 0=basic)	0
Installation Year	2022
LCOE	$ 0.146

Results

Cost Test Results	20-yr	10-yr
RIM	1.004	0.834
PCT	1.091	1.183
TRC	0.728	0.585
PAC	8.007	5.741

Discounted Payback Metrics	
Discounted Payback Years - prior to buydown	> 20 yrs
Discounted Payback Years - after buydown	15

Average Bill Savings ($/kWh generation)	
Years 1-5	$ 0.061
Years 1-10	$ 0.073
Years 1-20	$ 0.102

Buydown Incentive Summary	
Calculated Buydown Incentive per Active Customer	5,740
Calculated Buydown Incentive ($/kW-ac nameplate)	1,300
PV Costs over Payback Period	$10,870
PV Benefits over Payback Period incl Incentive	$5,129
Benefit - Cost Ratio over Payback Period	1.00
LCOE Net of Incentive	$ 0.030

Allocation of Buydown Incentive	
Annual Adoptions	100,000
Total Buydown Incentive ($)	**574,035,930**
Share paid by General Fund (%)	75%
Share paid by NEM 1.0 and 2.0 Customers	25%
Buydown Incentive paid by General Fund ($)	**430,526,947**
Share included in RIM (%)	25%
Buydown Incentive in RIM ($)	**$ 1,435**
Include Buydown Incentive in TRC (1=yes, 0=no)	0
Number of NEM 1.0 systems	616,308
Number of NEM 2.0 systems (end 2019)	413,982
Collect Charge from NEM 1.0/2.0 CARE customers (1=yes, 0=no)	0
Share of Customers that are CARE	12.8%
Non-CARE NEM 1.0 and 2.0 charge ($ per customer-mo)	**$ 13.31**