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.	R.20-08-020

RESPONSE OF THE JOINT IOUS TO THE ADMINISTRATIVE LAW JUDGE'S RULING SOLICITING RESPONSES TO RULING QUESTIONS

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Pursuant to the Administrative Law Judge's (ALJ's) February 28, 2023 Ruling Soliciting Responses to Ruling Questions (Ruling), Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) (collectively, the Joint Utilities) respectfully submit their response to the Ruling.[1]

RESPONSE TO RULING QUESTIONS

A. Current VNEM Tariff Data

1. Compared to a renewable electrical generation facility under the current net energy metering tariff, what are the unique quantifiable benefits, if any, of such a facility under the current VNEM tariff for the VNEM participant, the utility, and the electrical system?

The Joint Utilities interpret questions 1 and 2 as asking if there is reason to think that the cost effectiveness test results for VNEM systems are meaningfully different than the cost effectiveness test results for standard NEM systems. While there are differences between the cost effectiveness assumptions, none of these are sufficient to change the conclusions that Decision (D.) 22-12-056 reached regarding the standard tariff. These differences are summarized in Table 1 below. Therefore, VNEM systems, like NEM systems, increase costs for all customers of the electrical system (TRC) and rates/bills paid by non-participants (RIM) to the benefit of participating customers.

[1] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, SCE is authorized to sign and submit these comments on behalf of SDG&E and PG&E.

Table 1: Summary of Cost Effectiveness Test Assumption Differences of VNEM vs. Standard NEM 2 Systems		
SPM Test	**VNEM Benefits**	**VNEM Costs**
Total Resource Cost (TRC)	Possibly slightly lower, depending on configuration and degree of exports	Installation costs can be lower due to scale, but mixed evidence that this is currently realized. Incremental billing/interconnection costs are higher.
Participant Cost (PCT)	Bill savings are slightly lower because consumption, and therefore non-bypassable charges, is not reduced by onsite offsets– approximately 1 cent per kWh generated.	Installation costs can be lower due to scale, but mixed evidence that this is currently realized. Also, actual cost to benefiting accounts is a function of how system owner passes through costs.
Ratepayer Impact (RIM)	Possibly slightly lower, depending on system configuration and percent of generation exported.	Bill savings are slightly lower due to no NBC reduction from onsite offsets – approximately 1 cent per kWh generated. Incremental billing/interconnection costs are higher.

VNEM Participant: From a bill savings perspective, current VNEM tariffs generally provide very similar compensation as the general market NEM 2.0 tariff. The exceptions are (1) Solar on Multifamily Affordable Housing (SOMAH) participants can opt out of time of use (TOU) rates (potentially decreasing bills if the customer would be better off on non-TOU rates), and (2) unlike general market NEM2 customers, VNEM customers pay non-bypassable charges (NBCs) based on their consumption from the grid, without any netting. On balance, the benefits to VNEM customers reflected on their bills when offsetting consumption with allocated kWh credits are not meaningfully different than the NEM 2.0 energy offset.

Utility/Electrical System: For program cost-effectiveness analysis, the system benefits may be estimated using the avoided cost calculator (ACC), and can reasonably be assumed to be approximately the same as NEM/NBT systems as calculated in the rest of the proceeding. Note that the ACC implicitly assumes all generation is intended to offset on-site consumption; if any NEM system exports onto the secondary, primary, or transmission systems, the benefits of avoiding losses and avoided Transmission and Distribution (T&D) capacity could be reduced. If a VNEM arrangement spans multiple service delivery points, it becomes more likely that generation will be exported, thus reducing ACC benefits that can only accrue to on-site consumption.

2. Compared to a renewable electrical generation facility under the current net energy metering tariff, what are the unique quantifiable costs of such a facility under the current VNEM tariff for the VNEM participant, the utility, the electrical system, and all ratepayers?

Non-Participant Costs: As stated above, the bill savings from VNEM systems are likely slightly lower than standard NEM systems, but not by a significant margin. Thus, the cost shift associated with VNEM benefitting accounts is comparable to that from NEM 2.0 systems.

Non-participants also bear the costs of SOMAH incentives, to the extent that program incentives are analyzed as part of VNEM.

Installation Costs: The November 10, 2022 Proposed Decision (PD) recognizes that VNEM systems are closer in scale to small/medium commercial solar systems than typical residential systems, used a lower installation cost ($2.33/W vs. $3.30/W).[2] However, final system costs may significantly vary from project to project due to permitting requirements, availability of space to install panels, electrical interconnection, metering requirements, etc. In addition, although final system costs may be quantifiable, the relationship between the system owner and benefiters is unknown, so it is difficult to determine how system costs are ultimately socialized among benefiters. For example, it is possible that landlords would embed any financial benefits of lower utility bills in higher rents (reflecting the amenity benefit), leaving benefiting accounts indifferent to worse off due to the VNEM system.

Billing Costs: Because of complexities that arise from alignment of the billing cycle for benefiting customers in VNEM, customer turnover, and necessitation of manual validation, VNEM billing costs are often elevated above those of Standard NEM. Nevertheless, the impact of these billing costs on the overall cost remains minimal from a cost effectiveness perspective and therefore does not

[2] PD, Appendix B - Modeling Inputs and Results, p. B-4. The final decision does not explain why the PD's section on VNEM inputs was stricken from the final.

move the needle on how VNEM contributes to an overall cost-shift from participating to non-participating customers.

3. For investor-owned utilities (Utilities) only: Describe the multi-tenant landscape in your service territory by answering the following:

a) How many properties are currently interconnected under a VNEM tariff? How many total benefiting accounts are associated with those VNEM arrangements? What portion of these interconnected properties are 1) residential properties on a standard VNEM tariff, 2) properties on a Multifamily Affordable Solar Housing (MASH) VNEM tariff, 3) properties on a Solar on Multifamily Affordable Housing (SOMAH) VNEM tariff, 4) mixed residential and non-residential properties, and 5) non-residential properties. Within each of the previous categories, how many are located in a disadvantaged community, as defined in Decision (D.) 22-12-056)? What is the cumulative capacity of systems in each of these categories?

SDG&E has 647 standard VNEM generating facilities, including properties taking service under the MASH and SOMAH tariffs. The cumulative capacity of these systems is 2.85 MW.

SCE has over 400 VNEM "arrangements" consisting of approximately 810 VNEM generating facilities (including SOMAH and MASH systems) with a cumulative solar capacity of just over 48MW.

PG&E currently has 1,441 interconnected VNEM systems, accounting for 59.8 MW of solar capacity. However, primarily due to a time lag between interconnection and when VNEM arrangements appear in the billing system with associated benefiting accounts, the total installations/capacity from the responses for the rest of this response total 1,400 installations/58 MW. There are currently 17,730 benefiting accounts. See table below for the remainder of this response. [3]

[3] Based on publicly available PG&E interconnection data, available at: https://www.californiadgstats.ca.gov/downloads/#_nem_cids

Table 2: PG&E VNEM Participation Data				
Category	Total Count	Total Capacity	DAC Count	DAC Capacity
Residential VNEM	178	3.52	34	0.4
Mixed Residential and Non-Residential	191	6.99	20	0.93
Non-Residential	89	17.55	14	1.73
MASH	857	25.08	191	5.7
SOMAH	85	4.83	7	0.35
Total	1,400	57.97	266	9.11

b) How many properties on a VNEM tariff have solar and storage in front of the meter in a VNEM arrangement? What is the cumulative generation capacity of these systems?

Neither SCE nor SDG&E have any in front of the meter VNEM paired storage projects. PG&E has one such system, which has 59kW of solar and 13kW of storage.

c) How many properties on a VNEM tariff have energy storage systems installed separately behind the meter for a common area or similar end-use? (In this case the energy storage system may not be providing bill credits to any tenant benefiting accounts.) What is the cumulative generation capacity of these systems?

None of the Joint Utilities have any VNEM properties with BTM energy storage systems.

B. Successor to the VNEM Tariff

4. Is a "virtual" billing arrangement the best way to comply with the guiding principles of this proceeding with regard to tenants of multi-meter properties? Describe the policy and/or technical reasons behind each of your answers to a) through e).

It is unclear what the alternative to a virtual billing arrangement would be (e.g., individually wired systems to each meter), but we believe a virtual allocation of Net Billing Tariff (NBT) credits is a reasonable evolution of existing VNEM tariffs. As discussed below, the Joint Utilities believe their proposed virtual net billing framework, mirrored after the recently approved NBT, conforms within the guiding principles set by the Commission in D. 21-02-007 of this proceeding.

NOTE: For the rest of the response, we will refer to this successor tariff framework as NBTV (Net Billing Tariff Virtual).

> a) If yes, how can the current VNEM tariff be modified to achieve consistency with the adopted net billing tariff?

NBTV should compensate all metered exports at the same Avoided Cost Calculator (ACC)-based export credits as the adopted net billing tariff. This will ensure consistency with the NBT and allow compensation to be transparent and aligned with the benefits provided by that generation.

> b) If yes, are there VNEM arrangement conditions that justify different treatment in the tariff, such as generating and benefiting accounts sharing a point of common coupling?

The Joint Utilities do not propose any changes to the existing conditions (such as eligibility, size to load and metering requirements) on VNEM arrangements for NBTV, in the context of its proposal to compensate all metered exports from onsite generation at ACC-based rates. The Joint Utilities reserve the right to propose changes in the context of other party proposals that still compensate metered exports at retail rates.

> c) If yes, should the successor tariff be differentiated by customer segment? If yes, what segmentation would you recommend and why?

Yes, it is reasonable to differentiate the tariff by customer segment. While the core ACC based compensation should be consistent across all customer segments, the Joint Utilities believe it is reasonable to use the NBT ACC Plus mechanism into NBTV to provide higher compensation to residential customers (or a subset class, such as low-income residential customers) and bring NBTV compensation closer to that provided to standard NBT residential customers. Given the absence of any ACC Plus adders for the non-residential NBT segment and that primary purpose of VNEM is to enable solar installations for multifamily housing, the Joint Utilities do not propose any NBTV ACC Plus adders for non-residential benefiting accounts.

> d) If no, are there rate schedules or other rate products that could be used instead of a VNEM successor tariff? What are the quantifiable costs and benefits of your proposed alternative? How do the quantifiable costs and benefits of your proposed alternative compare to those of the current VNEM tariff?

N/A

e) If no, are there technology-based alternatives that could be used instead of a VNEM successor tariff, such as available hardware or software solutions? How do these quantifiable costs and benefits compare to those of the current VNEM tariff?

N/A

5. How do your answers to question 4 comport with the guiding principles of this proceeding, including the requirements of statute and California's climate objectives as addressed in D.22-12-056? Are there other equity considerations to recommend beyond these?

The Joint Utilities' proposed modifications to VNEM align with the Net Billing Tariff (NBT) established by D.22-12-056. For the same reasons the Commission determined the NBT to satisfy the Guiding Principles and statutory requirements, so too would the modified virtual tariff.

Concerning export compensation rates, the Commission determined that "continuing to base retail export compensation rates on retail import rates does not comply with Public Utilities Code Section 2827.1, thereby conflicting with one of the guiding principles."[4] As the Commission explained: "retail import rates do not reflect the actual costs of the exports or the benefits the exports provide to all customers and the grid…"[5] The Commission also determined that use of avoided costs for export rates complies with at least three guiding principles—guiding principles (a), (b) and (g).[6] The same applies to exports interconnected under a virtual tariff. In alignment with the NBT, the NBTV should credit exports with values derived from the Avoided Cost Calculator as "avoided cost values … brings the cost of the successor tariff for utilities closer to its value."[7]

As the Commission found that a glidepath was necessary for the transition to the NBT, the Joint Utilities anticipate that the Commission will determine a glidepath necessary for the NBTV. The purpose of the glide path, as described in D.22-12-056, is to ensure the successor tariff meets the multiple statutory requirements (i.e., ensure sustainable growth, minimize cost shifts, and provide transparency to customers).[8] Use of an ACC plus adder to ensure a specific payback period (consistent

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[4] D.22-12-056, p. 104.

[5] *Id.*

[6] *Id.*, pp. 13-14, 104.

[7] *Id.*, p. 104.

[8] D.22-12-056, pp. 124, 128.

with the NBT) aligns with the Commission's intent to satisfy the multiple statutory requirements and also complies with guiding principles. In addition, the ACC plus adder can be adjusted to meet equity considerations, providing a higher adder for multi-tenant properties housing income-qualified customers.[9]

C. VNEM Successor Tariff Components

6. If the successor to VNEM involves onsite energy generation, describe whether and, if applicable, how the compensation provided for exported energy should differ from that adopted in D.22-12-056 for the Net Billing tariff.

All metered exports should be compensated at the same export compensation rates as the standard NBT. To the extent that this compensation is deemed to be too low for certain market segments, the difference should be made up through the ACC Plus mechanism used in the standard NBT. As SDG&E does not have ACC Plus adders for NBT customers, SDG&E recommends that in this case, the ACC Plus mechanism should be applied just to NBTV export compensation. This will ensure that compensation beyond that what the CPUC has deemed the generation is actually worth will be provided transparently to customers.

7. What rate schedules and rate components should be used in the successor to the VNEM tariff? Explain your reasoning.

NBTV benefiting accounts can take service on any currently available rate schedule, as the bill credits they are allocated are divorced from the rate design on which they take service. However, the utilities reserve the right to propose otherwise in the context of other party proposals that would retain retail rate compensation as part of the VNEM successor.

8. Explain whether netting of imports and exports for the benefiting accounts by time-of-use period should continue. If not, describe your recommended alternative(s).

It should not, as the Joint Utilities are proposing the use ACC-based prices to value the energy export (as described in Q6, above) and then allocating such value (in dollars) to the benefitting accounts. For context, no netting currently occurs for VNEM when assessing non-bypassable charges to benefiting

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[9] However, for the reasons explained in the Joint Utilities' November 30, 2022 Opening Comments on the November 10, 2022 Proposed Decision Revising Net Energy Metering Tariff and Subtariffs, the ACC plus adder should not be paid on net surplus generation, as the Public Utility Regulatory Policies Act of 1978 prescribes the price for such exports. (Joint Utilities Opening Comments, p. 4 (Nov. 30, 2022).)

accounts. Non-bypassable charge are based on their metered consumption from the grid, in compliance with D.16-01-044 and Resolution E-4792. Continuing to allocate kWh from a generating resource to benefitting customers that do not have hourly breakdown of allocated and consumed energy or have no information about the ACC-based pricing, do not provide any incentive for customers to modify their behavior to maximize the value of the resource. Benefitting accounts should receive the allocated value of the generating facility without complicated offsetting calculations while having their base rate as the guidance for energy consumption.

9. Parties discussed the proposed net billing tariff glide path in comments to the November 10, 2022, proposed decision. Should the Commission adopt a successor to the VNEM tariff that includes a glide path for all tariff participants or only income qualified participants? On what basis should the Commission make this determination?

The Joint Utilities agree that there should be a glide path for residential NBTV benefiting accounts. The rationale for income-qualified customers receiving a higher ACC Plus credit than other residential customers was to account for the effect of the CARE discount reducing overall bill savings. Since the utility NBTV proposal provides consistent compensation for all customers, there is no need for differentiation to achieve a nine-year payback for all customers. However, the CPUC may find it reasonable to still provide faster payback times for systems principally serving income-qualified NBTV customers; differentiating ACC Plus levels would be a transparent mechanism by which this could be achieved. The use of ACC Plus adders in NBTV is also an appropriate mechanism to ensure equity amongst customers and to comply with Public Utilities Code section 2827.1 directive to promote growth in disadvantaged communities.

The ACC Plus levels should be informed by the same payback methodology as used in the general market tariff to ensure consistency. In comments on the November decision, the utilities estimated that the required ACC Plus values ranged from $0.035/kWh to $0.0475/kWh.[10] If the CPUC opts to use a higher system cost assumption, the ACC plus levels would necessarily be higher. Given the greater importance of the ACC Plus to achieving a nine-year payback for NBTV than the standard NBT,

[10] Joint Utilities Comments on the November 2022 Proposed Decision, p. 9. Required changes to the CPUC model are described in detail in Attachment B of comments.

it would be reasonable for the NBTV ACC Plus to decline at a slower rate than the standard NBT ACC Plus.

10. Have projects under the current VNEM tariff experienced delays in receiving bill credits after permission to operate is granted? If yes:

Due to the billing complexities with these arrangements, the timing for bill credits to show on customer bills is longer than that of other NEM programs. The Joint IOUs have recently evaluated the cause of the additional set-up times and have improved process and staffing to lessen impacts to arrangement participants.

a) What changes, if any, to the arrangement initiation process would reduce or eliminate delays?

There are interconnection and internal process improvements that could be evaluated by the IOUs which would improve the timing for arrangement initiation. One example would be to include a step (and possible deficiency) in the interconnection process that would require applicants to reconfirm their benefitting allocation worksheet just ahead of permission to operate (PTO). It is common for benefitting accounts and allocations to change from the worksheet originally submitted at time of application, which causes additional manual work from billing teams to verify and correct before VNEM billing can be implemented.

b) What can be done to reduce the negative impacts of delays on generator/benefiting customers, e.g., informational outreach or the provision of estimated bill credits to benefiting accounts until the actual credits become available?

Due, in part, to the variability of solar production and possible changes to benefitting accounts month to month in multi-tenant facilities, the complexity of providing estimated bill credits would not result in positive customer experiences across the board. Instead, informational outreach could ensure customers are aware that they will be generating bill credits as soon as the project reaches PTO, which will be reflected in their billing. For example, PG&E’s PTO communication assures customers that generation credits are tracked beginning at PTO, even if the VNEM billing arrangement takes several billing cycles to be created. Additional communications could be provided to all generator and benefitting accounts that could inform them of expected impacts to their bill.

As explained above, the Joint Utilities' NBTV proposal would allow the utilities and system owner to calculate the value of the energy export and the allocation to benefiters' bills before the customers' bills are even calculated, thus providing transparency and simplicity to the settlement process.

11. After permission to operate is granted, property owners are able to verify that tenants are being properly credited as they receive information on the generated credits allocated but property owners lack access to the consumption data that would inform them of the net benefits of their systems. What is a fair and timely process for generating account customers to access a confidential generator/benefiting account report to assess the net benefits of their systems, and if there are existing processes, is there any need for standardization across utilities?

In considering this question, it is important to consider the privacy of all customers. If the Commission is considering requiring benefitting consumption data to be provided to generator owners, it should be provided in aggregate or with the explicit written consent of the benefiters. However, as proposed by the Joint Utilities, decoupling the generation from each customer's usage (that is, no net energy), the calculation of the value of the export can be done by simply referring to the meter reads of the generating account. Once meter reads are available, the utility or the system owner can calculate the value (in dollars) of the energy by multiplying the hourly export by the corresponding price derived from the ACC. One can then use the allocation table to calculate the value of the credits assigned to each benefiter (even if the benefiter's bill has not been calculated yet). The remaining step left for the utility is to calculate how much of the credit can be applied to the customer's current monthly to offset energy charges and whether a credit should be carried over to the following month. This simplicity also benefits the SOMAH program, where building owners may need to report tenants' bill credits as part of establishing utility allowances for customers receiving housing benefits.

12. What fees should be charged for interconnection, billing, and/or other costs associated with successor tariff arrangements? Resolution E-4881 adopted many key elements for VNEM tariff implementation, such as set-up fees, allocation of unused credits, changes to billing arrangements, etc. Specify in your response if any of these requirements should be modified or omitted.

Recognizing that interconnection costs change over time, the Commission provided for a mechanism for each utility to update their interconnection fees via a Tier 2 advice letter. Given that the costs of billing setup and maintenance for virtual arrangements also change over time, the Joint Utilities suggest that the Commission authorize the Joint Utilities to update billing fees for virtual arrangements (such as one-time setup fees, benefitting account allocation changes, connect/disconnect updates, etc.) via a similar Tier 2 advice letter filing.

13. What new or revised tariff elements would best enable a VNEM successor system with storage to provide grid benefits, bill benefits for tenant accounts, and/or resiliency in case of an outage? Should this apply to the MASH and SOMAH VNEM tariffs?

A successor tariff with exports credited based on ACC and any adders would provide sufficient price signals to VNEM generator and storage operators to program their storage device to dispatch at the most beneficial time to draw the highest value for the benefitting tenants and the grid at large.

The joint Utilities have recently approved designs that would allow for resiliency in a VNEM arrangement with a storage device, which would remain as approved designs for a successor tariff.

As an alternative to battery storage paired with the renewable VNEM generator, individual unit battery storage may provide a more equitable and direct method to providing resiliency to tenants for multi-family properties. Self-Generation Incentive Program (SGIP) or otherwise-funded individual batteries could participate in Virtual Power Plant programs (VPP), as a benefit to the grid in times of high demand, while providing back-up power to tenants during grid outages. Since these batteries would not be paired with a renewable generator, they would not receive credits for exports. However, incentives would be possible through participation in a VPP. Such a configuration could prove challenging for retrofitting some existing buildings, due to clearance requirements and electrical constraints, but designing new buildings with per unit battery storage seems feasible and desirable because of the clear tenant benefits.

14. Should storage in a VNEM or a VNEM successor tariff arrangement be allowed to charge from the grid prior to Public Safety Power Shutoffs as articulated for NEM-related tariffs in D.20-06-017 Ordering Paragraph 5? Why or why not? If yes, what regulations, technical controls, or other provisions are needed? Should this apply to the MASH and SOMAH VNEM tariffs?

The current VNEM requirement that storage devices must only charge from the renewable generator should remain as a requirement in the successor tariff to ensure credits are only given for renewably generated electricity. The joint Utilities are not necessarily philosophically against allowing grid-charging prior to Public Safety Power Shutoffs, however current technical solutions to achieve the VNEM requirement do not allow for temporary suspension to allow grid-charging.

D. Net Energy Metering Aggregation (NEMA) Questions

General NEMA Questions

15. Compared to a renewable electrical generation facility under the current net energy metering tariff, what are the unique quantifiable benefits, if any, such a facility under the current NEMA subtariff to the NEMA participant, the utility, and the electrical system and all ratepayers? What unique quantifiable non-participant benefits, if any: a) do customer-sited renewables in regions with low population density have relative to those in high population density areas and b) does allowing aggregation of customer generators provide?

While there are significant differences between NEMA and VNEM, the overall conclusion that none of the differences between the VNEM and NEM are significant enough to change the overall cost effectiveness findings holds for NEM-A as well. In the rest of the response to questions 15 and 16 we address any differences relative to VNEM.

Utility/Electrical System: The benefits are calculated by the avoided cost calculator (ACC) and can be reasonably be assumed to be approximately the same as NEM/NBT systems as calculated in the rest of the proceeding. Note that the ACC implicitly assumes all generation is used behind the meter; to the extent any NEM system exports onto the secondary, primary, or transmission systems the benefits of avoiding losses and avoided T&D capacity could be reduced. To the extent a NEM-A arrangement spans multiple service delivery points, it becomes more likely that generation will be exported.

16. Compared to a renewable electrical generation facility under the current net energy metering tariff, what are the unique quantifiable costs, if any, of such a facility, under a NEMA subtariff to the NEMA participant, the utility, and the electrical system and all ratepayers?

NEMA does not require any special treatment vis-a-vis interconnection. The process is the same for NEMA as it is for Standard NEM and all other NEM subtariffs. The data shows that on average NEMA interconnection costs are around 3 times the cost of Standard NEM interconnections. These are not unique costs, instead they are reflective of the increased interconnection costs for these systems. On average, NEMA generators are larger than standard NEM generators, requiring greater upgrade costs. These generators also tend to interconnect to more isolated and rural feeders and by nature of the subtariff there are multiple meters associated with each generator. All of the above are cause for greater interconnection costs under this subtariff.

17. For Utilities: Describe the NEMA landscape in your territory by answering the following:

a) How many properties are currently interconnected under a NEMA subtariff? What portion of these interconnected properties are 1) residential, 2) mixed residential and non-residential, 3) non-residential, and 4) located in a disadvantaged community? What is the cumulative capacity of systems in each of these categories?

SDG&E has 3,540 properties interconnected under NEMA. The cumulative capacity of the systems is 7.38 MW. SCE currently has 1,433 NEMA generating facilities with a cumulative solar capacity of 164MW. PG&E currently has 8,040 NEMA properties, accounting for approximately 844 MW of solar capacity. However, primarily due to time lags in when NEMA arrangements appear in the billing system with associated benefiting accounts, the total installations/capacity by customer category detailed below reflects a total 7,051 installations/786 MW, a level from approximately mid-2022. See table below for the adoption and capacity counts within each category.

Table 2: PG&E NEMA Participation Data

Category	Total Count	Total Capacity	DAC Count	DAC Capacity
Residential	2307	25.95	353	4.61
Mixed Residential and Non-Residential	2357	202.39	654	99.44
Non-Residential	2387	557.9	832	267.28
Total	7,051	786.24	1,839	371.33

b) How many properties on a NEMA sub tariff have solar and storage in front of the meter in a NEMA arrangement? What is the cumulative generation capacity of these systems?

Neither SDG&E or SCE have any properties on NEMA that have solar and storage in front of the meter. PG&E has 181 such properties, accounting for 10.7 MW of solar and 5.7 MW of storage.

> c) How many properties on a NEMA subtariff have batteries installed separately behind the meter? What is the cumulative generation capacity of these systems?

SDG&E has 46 properties on NEMA with a battery installed separately behind the meter. The cumulative generation capacity of these systems is 1.8 MW. SCE has 27 NEMA generating facilities with energy storage sited with their solar systems with a total storage capacity of 1.6 MW. PG&E has 17 such properties, accounting for 2.2 MW of solar and 0.5 MW of storage.

18. Are current import rates used by NEMA participants cost-based?

There are no restrictions on what rates can be used on NEMA, and nearly every rate offered by the utilities is used in a NEMA arrangement. Consequently, import rates used by NEMA participants run the range from "very far from cost based" such as tiered, non-TOU rates (under NEM 1.0) and TOU rates which still have legacy TOU periods to the "more cost based" commercial and industrial rates. That said, even NEMA benefiting meters on AG-C, PG&E's agricultural rate with the highest demand charges and lowest volumetric rates, still causes a cost shift under NEM/NEMA since the average bill savings from a solar generator exceed the value of the generation by a significant margin. [11]

19. Should demand response or energy efficiency measures be added for NEMA service eligibility or as an alternative to NEMA?

The Joint Utilities interpret this question as asking if installation of demand response (DR) or energy efficiency (EE) measures should be a requirement for enrollment in NEMA. The Joint Utilities believe that it is reasonable to encourage customers to look for all opportunities to improve energy efficiency to reduce load before installing onsite generation. However, to keep consistency with other net metering options (e.g., VNEM, NBT), the Joint Utilities do not believe implementation of DR or EE measures should be a requirement for enrollment in NEMA. Additionally, since EE and DR programs

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[11] Ex. IOU-02 (Rebuttal Testimony admitted into the record of this proceeding), Figure VI-12, p. 111. Note that this analysis was based on 2021 rates and the 2021 ACC. While the 2022 ACC has slightly higher solar values, rates have since increased by a greater margin so the estimate of $0.11/kWh-generated cost shift from AG-C is likely lower than it is today.

serve different purposes to NEMA, it is unclear to the Joint Utilities how EE/DR programs could be used as an alternative to NEMA.

E. **Successor to the NEMA Subtariff**

20. Is a "virtual" billing arrangement the best way to comply with the guiding principles of this proceeding with regard to properties eligible for NEMA? Describe the policy and/or technical reasons behind each of your answers to a) through e)

The CPUC has no statutory obligation to continue to offer any version of NEM,[12] including NEMA, which is inherently tied to the capped NEM 1.0 tariff, as authorized by Public Utilities Code section 2827. Resolution E-4854, which required NEM-A for small IOUs, recognized that "the small IOUs are currently under no statutory obligation to continue offering NEMA after they have reached their NEM caps."[13] Likewise, major municipal utilities (which were also subject to the requirements of SB594) that have switched to a successor tariff do not appear to offer aggregation of any kind on their successor tariff.[14] Further, SB 594 only allowed for the CPUC to authorize NEMA if "the commission determines that allowing eligible customer-generators to aggregate their load from multiple meters will not result in an increase in the expected revenue obligations of customers who are not eligible customer-generators." Resolution E-4610 made this determination, noting "key assumptions:"

1) NEM penetration is limited by the NEM program cap in Public Utilities Code § 2827 and is therefore held constant in the base case and the SB 594 implementation case.
2) NEM aggregation will likely be utilized primarily to offset the load of non-residential meters and will increase the proportion of larger NEM projects relative to smaller residential projects.

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[12] *See* AB 327, Public Utilities Code § 2827.1 (making NEM programs permissive, not mandatory).

[13] Resolution E-4854, p. 16. Based on review of BVES and PacifiCorp successor tariffs, BVES does not offer aggregation as part of their successor tariff, while PacifiCorp allows Aggregation, with all allocated credits set at the export compensation rate. See https://www.bvesinc.com/assets/migrated/managed/ratechange2022/AL_439_E_Rates.pdf and https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/rates/NB-136_Net_Billing_Service.pdf

[14] For example, SMUD closed NEM-A to new applications on 12/31/2016, well before establishing their successor tariff, and does not offer aggregation as part of its successor tariff. See https://www.smud.org/en/Going-Green/Solar-for-Your-Home

3) Due to lower non-residential rates, non-residential NEM projects cost non-participating ratepayers comparatively less per kWh of exported generation than residential customers.[15]

The Commission concluded:

> "While the NEM program overall represents a net cost to ratepayers, through SB 594 implementation, the NEM program is likely to be more frequently subscribed by larger DG resources with a lower cost per kWh exported, which result in a lower cost to ratepayers. Therefore, meter aggregation of larger DG systems will likely improve the cost-effectiveness of NEM and lower its overall impact on non-participating ratepayers."[16]

The utilities have argued that, given the centrality of the NEM cap to the logic in Resolution E-4610, NEMA in the context of the uncapped NEM 2.0 tariff does increase costs for non-participating customers and is therefore no longer complies with the statute. The Agricultural Energy Consumers Association (AECA) insisted that "the Joint Utilities overstate the importance of the then-existing cap to the cost shifting analysis" and that "nowhere [in E-4610] does it state that the existence of a cap was the primary reason the Commission found NEMA would not shift costs." [17]

Putting aside that the resolution clearly does identify the cap as a primary reason, AECA's current position, disregarding of the importance of the cap, is contradicted by their own arguments in favor of the Commission adopting the resolution. Specifically, AECA and the California Farm Bureau Federation (CFBF) said in their reply comments on the draft version of Resolution E-4610 states:

> At the outset, it should be noted the appropriate analysis to conduct, as the Resolution does, is whether aggregation changes any impacts by comparing what the NEM program looks like with or without aggregation. It is that fundamental comparison which leads to the conclusion of the Resolution, and which PG&E attempts to miscast by suggesting a nonsensical comparison of aggregation to no net metering. Although how the costs and benefits of net metering ultimately measure up form myriad studies will be further debated, the Statute did not require an overall examination of net metering costs and benefits to reach the required finding. **What the Resolution appropriately recognizes is that the**

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[15] Resolution E-4610, pp. 3-5.

[16] *Id.*, p. 5.

[17] AECA Reply Comments on the November 2022 PD, p. 4

"headroom" currently existing between the NEM cap and the current penetration of NEM usage will likely be consumed more by non-residential customers under aggregation, who contribute substantially more to system costs than do residential customers.[18]

a) If yes, how can the current NEMA subtariff be modified to achieve consistency with the adopted net billing tariff?

If the Commission adopts a NEMA successor tariff (referred to as NBTA for the remainder of the response), it should use the same export compensation rates as the NBT. All metered exports from the NBTA generator account should be compensated at these rates. This will ensure that the NEMA tariff does not increase costs to non-participating customers, as is required by the legislation.

b) If yes, are there NEMA arrangement conditions that justify different treatment in the subtariff, such as generating and benefiting accounts sharing a point of common coupling?

No, as these are irrelevant to the value of the compensation being provided. While in theory arrangements that do not share a point of common coupling are more likely to export, this is moot as the proposed export compensation assumes that all generation is used behind the meter and is therefore an upper bound for the value actually being provided by NEMA generators.

c) If yes, should the successor subtariff be differentiated by customer segment? If yes, what segmentation would you recommend and why? For example, should a subtariff be established specifically for agricultural customers (e.g., customers eligible for PG&E AG-1)?

There is no statutory or policy basis to distinguish NEM-A by customer class. Under our proposal, NBTA would have consistent compensation rates across all customer classes.

d) If no, are there rate schedules or other rate products that could be used instead? What are the quantifiable costs and benefits of this type of alternative? How do the quantifiable costs and benefits compare to those of the current NEMA subtariffs?

N/A

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[18] CFBF/AECA Response to Comments Submitted September 5, 2013 on Draft Resolution E-4610, p. 2 (emphasis added), available at https://www.recolteenergy.com/wp-content/uploads/2019/04/september_9_2013_california_farm_bureau_reply_comments.pdf

e) If no, are there technology-based alternatives that could be used instead of a NEMA successor subtariff, such as available hardware or software solutions? How do the quantifiable costs and benefits compare to those of the current NEMA subtariffs?

N/A

21. How do your answers to question 20 comport with the guiding principles of this proceeding, including the requirements of statute and California's climate objectives as addressed in D.22-12-056? Are there other equity considerations to recommend beyond these?

Beyond the response to question 5, any extension of Aggregation must comply with SB594. This is a far stricter statutory standard against cost shifting than the Commission used under Section 2827.1 to develop the NBT in D.22-12-056. There is no balancing test for aggregation – the law mandates that the successor tariff version of NEMA shall not increase costs to non-participating customers, meaning that all metered exports be compensated at avoided cost. Any netting methodology that retains retail rate-based compensation violates the statute.

F. NEMA Successor Subtariff Components

22. How should netting be addressed in a NEMA successor subtariff (e.g., no netting as articulated in D.22-12-056, 15-minute intervals, time of use-based intervals, etc.)?

No netting should be used. All metered exports must be compensated at the same export rates as the standard NBT. Netting for NEMA is currently done in the same manner as VNEM, which is explained in detail in response to Q8.

23. Should NEMA customers be required to take service on specific cost-based import rates?

Residential NBTA generating accounts should have the same requirement as NBT residential customers to take service on an electrification rate. Non-residential NBTA generating accounts and all NBTA benefiting accounts can take service on any currently available rate. Consistent with NBT, customers cannot retain legacy rate treatment. As discussed previously, no netting should be used. However, the utilities may recommend rate requirements for benefiting accounts in the context of other proposals which retain any compensation of exports at retail rates.

24. What fixed costs do NEMA customers currently avoid and how should these fixed costs be recovered from NEMA customers? What are the annual Utilities' administration costs of NEMA? If non-participating ratepayers should be responsible for these fixed and administrative costs, why?

NEMA customers avoid all fixed costs embedded in volumetric rates to the extent those volumetric rates exceed avoided costs. Given that the 2022 ACC values solar at less than $0.05/kWh, this results in significant avoidance of contribution to fixed costs for all utility rate schedules.

SDG&E's annual interconnection administration costs for NEMA (for projects approved between 3/1/22-2/28/23) is $47,457.00. SCE's estimated annual billing costs to support NEMA is $207,525. PG&E's administration costs for NEMA is an average of $1,565,543 over the last five years. Non-participating ratepayers should not be responsible for these costs.

25. How can a successor NEMA subtariff be devised to meet the requirements of the statute and California's climate objectives as addressed in D.22-12-056 without creating/perpetuating a cost shift to non-participants? Should a successor subtariff to NEMA be approved if it does not pass the Standard Practice Manual Total Resource Cost test?

The utility NBTA proposal compensates all exported generation at avoided cost-based rates. By setting export compensation at avoided costs, NBTA would encourage participating generation accounts to export their generation at times that are most beneficial to the grid, thereby reducing emissions and increasing grid reliability. As participants would be compensated at avoided cost to the utilities, this would not create or perpetuate a cost shift to non-participants.

Additionally, the TRC test is irrelevant to the statutory requirements to offer aggregation under SB 594, as it doesn't capture any impact of the tariff on non-participants. Any "increase in the expected revenue obligations of customers that are not eligible customer-generators" would be treated as a transfer payment within the TRC test. Even more broadly than the specifics of Aggregation, the TRC cannot be the sole determinant of whether the subtariff meets statutory cost-effectiveness requirements. For example, D.22-12-056 approved the NBT for the general market even though it does not pass TRC. Nonparticipant impacts of NBTA would need to be analyzed through the RIM test, which would likely compare favorably to the NBT because a greater portion of the generation would be valued at avoided cost rather than retail rates.

26. Given that a successor NEMA subtariff might be based on a new structure, potentially similar to the net billing tariff structure, is there a way for the bill credit allocation method to be simplified and still comply with Public Utilities Code Section 2827 (h)(4)(C)?

We do not propose any changes to the allocation structure, as the transition to compensating exports on a single set of export rates rather than various retail rates will inherently simplify the process. However, the Joint Utilities reserve the right to propose changes in response to other party proposals that would retain retail rate netting and/or further complicate the billing process through other changes.

G. Net Energy Metering for Fuel Cells

27. Have any Commission decisions, resolutions, or dispositions been adopted since the ruling that should be considered? For example, D.21-06-005, D.21-07-011, and/or D.22-12-057 may have findings and direction relevant to net energy metering for fuel cells. Explain whether these determinations should be applied to net energy metering for fuel cells, and why.

As the question mentions, there have been multiple decisions subsequent to the ALJ ruling and comments that have addressed fuel cells, including those listed above in addition to D.22-12-003, and it is reasonable to consider if/how these subsequent decisions impact net energy metering for fuel cells. However, it is not clear to the Joint Utilities that any of the findings or orders from those decisions are relevant to net energy metering for fuel cells.

28. Have any other legal, regulatory, or technical developments occurred since the ruling and comments that should be considered? Explain whether these developments should be applied to net energy metering for fuel cells, and why.

The Joint Utilities are not aware of any other legal, regulatory, or technical developments occurred, other than those listed above, since the ruling and comments.

Respectfully submitted on behalf of the Joint Utilities,

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