BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas And Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	Application 22-05-022 (Filed December 2, 2022)
And Related Matters	Application 22-05-023 Application 22-05-024

CLEAN COALITION COMMENTS ON PROPOSED DECISION MODIFYING GREEN ACCESS PROGRAM TARIFFS AND ADOPTIONING A COMMUNITY RENEWABLE ENERGY PROGRAM

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TABLE OF CONTENTS

Recommended Changes

- Reject the use of ReMAT and the SOC as underlying pricing for a new Community Solar program. Just as the PD argues that Community Solar projects are dissimilar to Net Energy Metering projects, infill Community Solar projects are also dissimilar to 20 MW projects and should not be treated as such. The ReMAT/SOC pricing is too low to support the development of projects and the lack of specificity of how the existing programs will mesh with unique characteristics of Community Solar limits any possibility of success.
- Allow the use of Rule 21 for interconnection rather than requiring the use of the wholesale distribution access tariff ("WDAT"), especially for projects not seeking compensation for capacity. A key provision of a successful FIT is streamlined interconnection. With the CAISO already struggling to keep up with a staggering number of new applications and historically large cluster studies, the solution for a successful new program is **not** to further add to the existing workload.
- Allow Community Solar projects to reduce Resource Adequacy ("RA") obligations for Load Serving Entities ("LSEs") via the California Energy Commission's ("CEC") existing procedure. With capacity providing a significant value stream and the deliverability study process taking multiple years to complete, the PD sets developers up for failure.
- Define "robust participation of low-income customers" more clearly to create a transparent and measurable standard for a phrase that is referenced in AB 2316 and throughout the PD. Relying on an ambiguous term as a weighing mechanism to determine the success of existing and future programs is not a good policy practice and will leave future iterations of the Commission guessing on the precedent set forth in this PD.
- Take into account that the Clean Coalition continues to join a broad coalition of parties in supporting the NVBT, though we have proposed modifications in multiple rounds of comments. If the Commission is set on adopting a FIT, the design initially proposed in the Clean Coalition's is far more appropriate for Community Solar resources than the failed ReMAT or SOC and will result in executed contracts that yield successful deployments.
- Add to the findings of fact that the Clean Coalition's FIT proposal ensures projects are deployed within a close proximity to subscribers, guaranteeing real value creation through avoiding the use of any transmission infrastructure and limiting the use of the distribution grid.

- Note the Clean Coalition's support for language in the PD that will require auto-enrollment of low-income customers to ease the difficulty of finding subscribers.

TABLE OF AUTHORITIES

Commission Decisions

Legislation

Commission Rules of Practice and Procedure

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Clean Coalition respectfully submits these comments in response to the *Proposed Decision* ("PD") *Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program*, issued at the Commission on March 4, 2024. The Clean Coalition is disappointed by the Commission's choice to reject the Net Value Billing Tariff ("NVBT") in the PD, which declares that it goes against state and federal law, and instead adopts existing Feed-In-Tariffs ("FIT") compensated using avoided costs based on the Public Utility Regulatory Policies Act ("PURPA"). The Clean Coalition often advocates for well-designed FITs and even initially proposed one early in this proceeding with adders for projects deployed on built environments, small projects, dispatchability, and disadvantaged communities. The proposal references pricing from the vert successful Los Angeles Department of Water and Power ("LADWP") FIT+ program and a FIT that the Clean Coalition designed for the City of San Diego to maximize the solar siting potential at built environments. Conversely, the FIT in the PD repeats errors made in the design of past front-of-meter ("FOM") programs adopted by the Commission that have led to low rates of project deployments and is therefore incapable of promoting robust participation by low-income customers. Without projects deployed, not just contracts executed, low-income customers will not benefit, let alone in a "robust" manner. As written, the PD will not result in a new community renewables program capable of meeting the legislatively mandated requirements in AB 2316 or the state procurement targets (e.g., robust participation by low-income customers and serving distinct customer groups). The state is already falling behind in meeting targets for customer-sited solar and resource adequacy from distributed generation; this PD will perpetuate the shift in the wrong direction.[1] Likewise, the 60 MW of additional capacity provided for the disadvantaged communities green tariff ("DAC-GT") program is not sufficient to incentivize substantial capacity deployed in or near DACs, particularly for Community Choice Aggregator ("CCA") administrators, whom have had the most success thus far.[2] The PD takes the position that neither the DAC-GT or CSGT programs have been successful, but perplexingly allocates less than the 73.89 MW of existing contracted resources worth of additional capacity, which does not allow for the modified DAC-GT to be any more successful than either of the original programs. It appears that the Commission is setting the modified DAC-GT up to fail by making it impossible to meet the standard of "robust participation by low-income customers."

As evidence by the lack of MW of capacity deployed in the existing programs offered in the PD as options for underlying compensation in a new Community Solar program—the Renewable Market Adjusting Tariff ("ReMAT") and the Standard Offer Contract ("SOC")—the new community renewables program will not result in successful deployments, let alone enough installed capacity to truly enable a flourishing market that truly benefits ratepayers unable to benefit from Net Energy Metering ("NEM") and put the state on track to achieve climate and energy goals. The base pricing is too low, will require a costly FOM interconnection that increases the time before deployment, does not enable dispatchability, and limits developer certainty. Prior to adopting any final decision, the Commission needs to consider – will the proposed program actually lead to a successful Community Solar market in California? Given the way the PD is currently written, the answer is a definitive no. The PD will worsen several of the original problems identified in the report by Evergreen Economics, which notes, "a major challenge in getting projects under contract is that the PAs have been unable to engage solar developers as a first step."[3] **Thus, the Clean Coalition urges the Commission to pull the PD**

[1] The rooftop solar industry contracted significantly in 2023, at a time when the state needs historic levels of growth sustained over the next decade. In 2022, CAISO forecasted 71.06 MW of deliverability from distributed generation. The actual amount was 66.06 MW. In 2023, CAISO forecasted 171.38 MW of deliverability; the actual amount was 56.2 MW. https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E1D1129D-F1F2-425F-98F2-F7D00297EAFE

[2] PD, at p. 139.

[3] *Process Evaluation of the Disadvantaged Communities Green Tariff and Community Solar Green Tariff* Programs. Evergreen Economics, at p. 3.

and go back to the drawing board, in time to meet the statutory deadline of designing a new program by July 2024. The PD opts to use a new Community Solar program to help reach capacity goals for existing programs that have had limited success and rely entirely on outside funding to overcome any shortcomings, which seems like a tactic to check the box of compliance with federal law more so than an attempt to develop a comprehensive program with the confidence that adoption will lead to a significant number of successfully deployed projects.

While the full details about how state and federal funds will be dispersed remain to be revealed, if the state funding ($33 million) is allocated to 3 MW ReMAT projects in the form of a $0.10/kWh over the duration of the 20-year contract, developers will deploy around 9 MW before the funds are fully spent.[4] Using the same adder, $200 million in federal funds will result in the addition of around 54 MW of capacity, for a total of 63 MW.[5] Even with these back-of-the-napkin calculations, the Clean Coalition can clearly identify that the PD does not put California in a position to develop a successful Community Solar program, let alone a long-lasting program capable of achieving "robust participation by low-income customers."[6]

II. DESCRIPTION OF PARTY

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER") — such as local renewables, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

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https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/solar-in-disadvantaged-communities/dac-gt-and-csgt-evaluation-final-report_033122v2.pdf

[4] This calculation includes usage of the 30% investment tax credit ("ITC") and a subscriber benefit of 15%.

[5] If funding is allocated from both the state and federal government for a single project, the total MW deployed will be reduced.

[6] AB 2316, Section 1(C).

III. REMAT AND THE SOC ARE NOT COMPATIBLE WITH COMMUNITY SOLAR. NEIETHER PROGRAM WILL RESULT IN SUCCESSFUL DEPLOYMENTS

In the PD, the Commission rejects the NVBT for legal reasons and selects a modified version of SCE's Community Renewable FIT. This choice is perplexing to say the least and will be disastrous for the future of Community Solar in California if adopted. Neither of the underlying tariffs have had any real success, especially in the last few years. ReMAT was reopened in 2020, modified in 2021, and no contracts were executed in 2022.[7] Likewise, the Clean Coalition is not aware that the SOC has been utilized thus far, much less for infill solar. Adding a Community Solar option only increases complexity to already underutilized programs, which is not an effective way to implement AB 2316. We do not believe that designing a program solely to avoid a possible legal challenge without also considering the real-world effects of the new program is a sound way to design policy. Doing so is missing the forest for the trees, to the detriment of low-income ratepayers who would save under a workable program.

The base pricing for both ReMAT and the SOC is too low to garner any significant interest from developers, which makes the PD a non-starter from the outset. The PD also requires a front-of-meter ("FOM") interconnection via WDAT and explains that a project must be studied via CAISO's deliverability process to receive any capacity value. This requirement adds between \$0.02-\$0.04/kWh in additional project costs and leads to years spent waiting in the interconnection queue before a deployment is possible, at which point the availability of additional funds is more of a gamble than an expectation. Thus, the PD proposes to reduce compensation (as compared to the NVBT) while imposing requirements that increase the cost per deployment. The Clean Coalition cautions that additional state and federal funds are not a magic solution capable of solving a fundamentally flawed base compensation program.

We also take issue with the complete lack of detail on how Community Solar will be integrated with the existing programs. ReMAT and the SOC are both structured differently and have dissimilar requirements; neither will work for Community Solar. The PD eliminates entirely any certainty in the development process, unnecessarily constraining potentially interested developers. This has been a critical problem in numerous prior FOM distributed generation programs in California. The lack of a clear and navigable pathway to ensure that a

[7] 2023 Padilla Report, at p. 17. https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2023/2023-padilla-report---final.pdf

well-designed project will lead to a deployment either results in few, if any, contractors willing to shoulder risk in the first place or a high volume of terminated contracts. So how does the Commission expect adding complexity to already uncertain and unsuccessful programs to result in a flourishing Community Solar market? Simply adopting a new program in no way guarantees that capacity will be deployed. A poorly designed program will be detrimental to the state in many ways, including shrinking a key market segment at a time when a historic deployment rate of renewables is needed to achieve energy and climate goals. Moreover, it is illogical for the Commission to bank on additional non-ratepayer funds as a silver bullet solution that covers up the myriad of underlying programmatic flaws, especially with the dispersion of funds not being synchronized with either ReMAT or the SOC. If a developer must secure full site control and complete the Fast Track interconnection process before being approved for compensation, as is the case with ReMAT, **and** there is no way to tell in advance whether additional funds will be allocated, the developer has little reason to shoulder the risk. High risk is even less palatable when the expected reward is low, making the low pricing in the PD particularly troublesome.

The furthest the PD comes to rationalizing the proposed FIT is to legally justify the need to use PURPA avoided costs and reference the language in AB 2316 that requires the use of non-ratepayer funds. There is no revenue modeling, consideration about what it will take to secure financing, reflection on differing costs for different types of solar, examination of energy storage and dispatchability, contemplation of the difficulties of WDAT interconnection, scrutiny over how ReMAT or the SOC may need to be changed, or discussion on whether a shared-savings model will reduce the number of deployments even further given already tenuous compensation. Whereas the NVBT was debated for close to a year with multiple rounds of additional comments, the record does not contain any evidence to support the conclusion that the proposed FIT will be successful. There is neither evidence suggesting that such a program design will garner significant interest from developers nor that it will lead to the development of a strong Community Solar market in California. Moreover, the PD lacks any sufficient discussion about the mechanics of each underlying tariff, why these two tariffs in particular are optimal for this market segment (e.g., technology type and project size), and how using either tariff might impact the likelihood of a project being awarded non-ratepayer funds from either a federal or state allocation. The Clean Coalition has long been an advocate of well-designed FITs with pricing based on market conditions; unfortunately, the recommendations in the PD do not meet the standard of a quality program. Just as the Commission did with the initial NEM 3.0 PD, it is far better to go back to the drawing board than to end up with a subpar result. With the eyes of the nation on California when it comes to renewable energy and Community Solar developers searching for a new market, this PD sets the stage for a massive failure, not success.

A. SOC

Without the ability to secure financing for projects, developers will not have the on-hand capital available to make the investment needed to deploy a Community Solar project. Typically, solar panels function for between 25 and 30 years, making the option for a long-term contract essential. There is significant evidence on the record from the Coalition for Community Solar Access ("CCSA") and other parties that securing financing for a project requires a clear demonstration of financial viability, including a long-term value stream from a contract of 20-25 years. The Commission has also heard this same issue in the Net Energy Metering ("NEM") Successor proceeding ("R. 20-08-020"), which is one of the reasons that the Net Billing Tariff includes a 20-year contract period.[8] In contrast, the SOC offers a contract term of 7 years for existing projects and 12 years for new projects.[9] Neither option is long enough to enable a developer to secure financing, making it extremely unlikely that any Community Solar project will be deployed using this option. Such a fundamental program flaw cannot be overcome solely by providing additional state and federal funds. The availability of other funds only increases the likelihood of a successful project deployment if the underlying tariff structure garners developer interest in the first place; the existing structure of the SOC does not, as evidenced by the lack of capacity deployed since the program was adopted by the Commission in 2020.

Beyond the lack of viability due to contract lengths that are far too short, the SOC pricing is simply not high enough, After analyzing the proposed prices in SCE Advice Letter ("AL") 5224-E, we can confirm that the pricing is not sufficient to support deployments of infill solar, completely pricing out any solar deployed on a built environment.[10] By proposing the SOC as an underlying tariff in this proceeding, the Commission is eliminating the potential for infill projects sited within a close proximity to the subscribers, limiting the avoided transmission and distribution value, and forgoing the chance to set the stage for community-level resilience. This

[8] See D. 22-12-056.
[9] See D. 20-05-006.
[10] SCE Advice Letter 5224-E

sends the signal that the state does not value efficiently deployed projects sited close to the load being served and that preserve California's pristine natural lands. For ground mount solar projects as well, the added costs associated with a WDAT interconnection and complying with the California Environmental Quality Act ("CEQA") will curb the potential for deployments, particularly of small projects.

Lastly, there is added complexity associated with the SOC due to the requirement that any developer seeking to deploy a project sized above 1 MW must go through the process of receiving Qualifying Facility ("QF") status from the Federal Energy Regulatory Commission ("FERC"). FERC also requires a developer to recertify QF status if there is any material modification, such as a design change or shift in project ownership. The requirement for QF status adds uncertainty and bureaucracy for a potential Community Solar developer, setting up a system that is difficult to navigate for new market participants. The lack of long-term contracts, low pricing, and added costs for compliance make the SOC incompatible with Community Solar.

B. ReMAT

With the SOC ruled out as an option for a successful Community Solar program, we now turn to the significant flaws with the current form of ReMAT. Acknowledging that the program was closed for several years, over the last 10 years, ReMAT has only led to an average of contracts for 5 MW of capacity annually. This number is **far** lower when factoring in that ReMAT has a high contract termination rate, meaning that most of these projects are never deployed. Following the re-opening of ReMAT, the Commission has adopted new requirements to ensure compliance with PURPA, including setting prices administratively based on recently executed Renewable Portfolio Standards ("RPS") contracts of between 1 and 20 MW over the last few years, allowing paired storage, and re-allocating capacity between categories.[11] Despite the changes, the "new" ReMAT has had very little success, resulting in few contracts executed and even fewer projects deployed. There are numerous problems with the program, the most fundamental of which is insufficient compensation.

The compensation for a ReMAT project is diluted because RPS projects that are far larger than any ReMAT project (e.g., above 3 MW and below 20 MW) are included in the sample size used to administratively determine pricing, despite larger RPS projects not being

[11] See D. 20-10-005.

representative of ReMAT projects (which are 3 MW or less). Using projects that are far larger than any ReMAT project to set pricing for ReMAT projects is illogical and sends the signal that the economics for all renewables are the same, when in fact this is not the case at all. Just as NEM projects are not compensated at the same rate as a 100 MW utility scale solar project, a 1 MW rooftop solar project should be compensated differently than a 20 MW ground mount solar project. There is no infill project sized at 20 MW, let alone an infill project of that size with paired storage. Yet, in the most recent update to the administrative pricing, Resolution 5270, only 20 of the 32 total RPS projects (63%) referenced are 3 MW or smaller. The remaining 12 projects drive down the compensation in each of the three ReMAT categories, limiting the opportunity for the program to be utilized. Breaking down the numbers further, it appears that only 16 of the RPS projects in the data set with executed contracts are expected to be in operation by the end of this year, meaning that the rest are not guaranteed to be successes. Many of the projects will likely end up with terminated contracts but will still impact ReMAT pricing despite not being economically viable. Of these 16 expected to be in service by the end of 2024, only 12 are 3 MW or smaller. Thus, only 12 of 32 projects are truly representative of ReMAT projects. Only these projects should be included in a data set used to administratively set prices. The others—far larger than ReMAT projects and with high contract termination rates—are significant contributors to the incongruency between pricing and the size of ReMAT projects that has limited the success of the program. Lastly, it is worth noting that of the 32 total projects included in the data set used for ReMAT pricing, only 5 projects are contracted with the IOUs. The majority are in CCA service territories, which speaks to the success that the CCAs have had when it comes to community-scale renewables and should signal to the Commission that far greater capacity should be available for CCA-deployments. The RPS proceeding ("R. 18-07-003" and the successor proceeding) are usually where issues with ReMAT are addressed, but <u>with the PD determining that ReMAT is an appropriate option for base compensation of a new Community Solar program, it is essential to understand exactly why ReMAT is unworkable.</u>

In addition to unfavorable pricing, there are several other issues with ReMAT that make the program incompatible with Community Solar. First, each utility has different TOD factors, further changing the economics for a potential project and making it far more difficult for a developer to work in multiple utility service territories. While TOD factors are not an overwhelming challenge, the dissimilarities represent an additional point of confusion that have limited the success of the current form of ReMAT and will dissuade developers from participating in the Community Solar market. Second, ReMAT has onerous requirements when it comes to the application process and interconnection. For a project to be eligible to receive compensation under ReMAT, the developer must be able to demonstrate 100% site control and have completed the WDAT Fast Track process, which is intended to take 6 months or less, but can end up taking over two years given the complexity of the project.[12] This requirement forces a developer to make a significant up-front investment, spending years and potentially hundreds of thousands of dollars without any notion of whether the project will be compensated under ReMAT at the end of the process, or for a potential Community Solar project, if any state/federal funds will even remain available by the time the process is completed. With such a significant risk associated with utilizing ReMAT, it is not a surprise that the program has had limited success over the last few years. Third, the PD does not take a position on how the capacity will be allocated for a Community Solar project that chooses to use ReMAT pricing. It is unclear whether a Community Solar project will be counted as capacity for the new Community Solar program or will reduce the remaining capacity available under ReMAT. Double dipping must not be permitted; likewise, the Clean Coalition believes that Community Solar must have its own unique capacity that does not interfere with legislatively mandated procurement targets for other programs, such as ReMAT. As seems to be a theme throughout these comments, ambiguity along with a lack of critical details demonstrates that the PD is not the solution that the state needs for Community Solar and will not result in an effective implementation of AB 2316. Like the SOC, ReMAT is also not a sufficient option to develop a burgeoning Community Solar market in California.

C. PAST COMMUNITY-SCALE RENEWABLES PROGRAMS HAVE RESULTED IN FEW DEPLOYMENTS, IN MAJOR PART DUE TO A LACK OF STREAMLINED INTERCONNECTION

One of the major sticking points the Clean Coalition has consistently raised in this proceeding is the need for streamlined interconnection. The IOU's FOM interconnection procedures, via the WDAT, have not been streamlined at the same rate as Rule 21

[12] The Valencia Gardens Energy Storage ("VGES") project the Clean Coalition worked on, a CEC EPIC grant funded project. Delays in the interconnection process and surprise upgrades resulted in a process that was expected to take six months ended up taking two years and costs ballooned from $156,999 to $460,887. https://clean-coalition.org/community-microgrids/valencia-gardens-energy-storage-project/

interconnection (due to the R. 17-07-007 and predecessor rulemakings). The difference between a Rule 21 interconnection and a WDAT interconnection is multiple years and as much as $0.02-$0.04/kWh. The added cost and time burden is enough to prevent most projects from reaching a commercial operations date. See the table below, which shows the differences in cost and the duration of the interconnection process for 1 megawatt (MW) projects applying for a BTM interconnection versus a WDAT Fast Track interconnection.

Factor	BTM 1 MW rooftop project	FOM 1 MW rooftop Fast Track project
Typical cost	$37,500	$312,450
Typical timeframe	302.5 business days	723 business days

The interconnection process for a typical FOM project costs more than eight times as much as the typical BTM project and will likely take more than twice as long as a BTM project. As part of the Peninsula Advanced Energy Community (PAEC) initiative,[13] the Clean Coalition team studied 209 FOM interconnection applications and found that 82% failed to secure permits or dropped out. The remaining 18% of applications that were approved took between 6 months and 2.25 years. The Green Power Institute's ("GPI") *A Modern Cinderella Story: Assessing the state of California's Community-Scale renewable energy market* underscores the lack of success with previous FOM programs passed by the Commission:

> The following table summarizes seven key procurement programs from the last decade and shows that most have largely failed, for various reasons, showing that on average only 28 percent of the megawatts allocated to each of these programs have come online over the last 15 years.[14]

[13] As part of the PAEC Initiative, the Clean Coalition created a pilot for streamlining interconnection (see https://clean-coalition.org/peninsula-advanced-energy-community/interconnection)
[14] GPI. *A Modern Cinderella Story: Assessing the state of California's Community-Scale renewable energy market*, at p. 4.

	PG&E	SCE	SDG&E	Total
PURPA MW allocated	NA	NA	NA	NA
PURPA contracted 2007-2017	39.2	0	30	69.2
PURPA online 2007-2017	0	29.8	0	29.8
Online as % of allocated	NA	NA	NA	NA
PV PPA MW allocated	500	500	0	1000
PV PPA contracted	272.5	64.9	0	337.4
PV PPA online	199	56.9	0	255.9
Online as % of allocated	40%	11%	NA	26%
AB 1969 MW allocated	209.2	247.6	40.2	497
AB 1969 contracted	64.5	120.1	15	199.6
AB 1969 online	64.5	115.6	9.5	189.6
Online as % of allocated	31%	47%	24%	38%
ReMAT MW allocated	218.8	226	48.4	493.6
ReMAT contracted	31.9	48.4	12.5	92.8
ReMAT online	27.5	30.4	7.6	65.5
Online as % of allocated	13%	13%	16%	13%
BioMAT MW allocated	111	114.5	24.5	250
BioMAT contracted	19.8	6	3	28.8
BioMAT online	4.6	0	0	4.6
Online as % of allocated	4%	0%	0%	2%
RAM MW allocated	653	756	165	1574
RAM contracted	370.4	635.4	87.6	1093.4
RAM online	331.2	635.4	57.6	1024.2
Online as % of allocated	51%	84%	35%	65%
SB 43 MW allocated	272	269	59	600
SB 43 contracted	56.4	95	40	191.4
SB 43 online	52.75	60	20	132.75
Online as % of allocated	19%	22%	34%	22%
All seven programs MW online as % of MW allocated				28%

California's major Community-Scale programs over the past 15 years

One of the major recommendations of the report is to dramatically streamline interconnection in ways that reduce the time/cost of interconnection with tools that include automation.[15] The Clean Coalition concurs, and our comments in the proceeding have raised this issue repeatedly. Yet, the PD takes the exact wrong approach when it comes to interconnection. Mandating the use of WDAT and going through the CAISO deliverability process is a **guaranteed way** to ensure that the Community Solar market is sluggish to start up and depending on the compensation, (e.g., if the final decision adopts ReMAT and the SOC) that it will never succeed.

IV. AS PROPOSED, THE PD WILL NOT ACHIEVE GOALS MANDATED BY THE LEGISLATURE OR LEAD TO A SUCCESSFUL COMMUNITY SOLAR MARKET IN CALIFORNIA

One of the main metrics that the Commission references repeatedly in the PD to judge the effectiveness of the existing Community Solar program and justify the new FIT proposal is the

[15] *Ibid*, at p. 25.

language in AB 2316 on the need to achieve "robust participation by low-income customers."[16] Yet, beyond the statement itself, no further information is provided that actually defines the term "robust" or underscores how the Commission intends to measure success other than comparing the new programs to the existing ones. The language in the PD condemning the existing programs as not meeting the requirement sets the bar so that any new program must be **more effective** at serving low-income customers than the status quo. **Based on this definition, the Clean Coalition wishes to make quite clear that the new proposed FIT and the modified DAC-GT program are not capable of achieving this standard.** The modified DAC-GT program does not provide enough additional capacity to be successful, certainly not more than the 73 MW that is currently online. Likewise, adopting ReMAT and the SOC as base compensation for a new Community Solar program will not lead to a significant number of deployments, ensuring that the California market continues to remain dormant by preventing the market from maturing in a way that benefits vulnerable Californians or brings the state any closer to achieving climate and energy goals. Without actual project deployments, low-income customers cannot possibly benefit from a reduced electricity bill. Lastly, the proposed FIT and modified DAC-GT do not increase reliability or resilience and certainly will not result in ratepayers using the grid in an intelligent fashion. Thus, the PD fails to achieve the requirements of AB 2316 and does not bring the Commission any closer to achieving the existing goals listed in the DER Action Plan 2.0 or ESJ Action Plan.

V. THE PD TREATS ALL TYPES OF SOLAR AS THE SAME, DESPITE THE RECORD SHOWING THAT INFILL SOLAR CREATES ADDITIONAL VALUE

The PD treats all types of solar as equally valuable, with the same costs and benefits, which ignores the additional value created by infill solar projects. Infill solar is the only way to guarantee that a solar project is deployed in proximity to subscriber, avoiding the need to go through the CEQA process[17] and preserving the state's pristine natural lands. Infill projects also avoid usage of transmission infrastructure—especially the high voltage transmission grid—reducing peak transmission usage, line losses, and congestion. Each reduction helps optimize market outcomes for other participants, to the benefit of the ratepayers. To ensure that

[16] AB 2316, Section 1(C).
[17] Projects deployed on a built environment (e.g., rooftops, parking lots, and parking structures) do not need to prepare an environmental impacts report.

Community Solar projects are sited in the communities being served, a more tiered policy that compensates different types of solar (e.g., infill vs. ground mount) and a proximity requirement (the Clean Coalition has proposed that projects be sited within the same distribution area as subscribers) will address the difference in deployment costs and value creation. For example, the LADWP FIT+ program, described below, has an incentive for small and large canopy/carport projects, recognizing that the economics are different for a carport solar project than for a ground mount solar project. In the same way that many FITs utilize tranches, the Commission should consider a tranche for infill projects.

VI. OTHER FIT PROGRAMS AROUND THE STATE ARE MORE EFFECTIVE THAN THE PROPOSED PURPA FITS. THE COMMISSION SHOULD REJECT THE USE OF REMAT AND THE SOC AND INSTEAD ADOPT THE CLEAN COALITION'S PROPOSED FIT

The Clean Coalition urges the Commission to consider FITs from around the state that have been successful as a needed part of the process of creating a new Community Solar program in California. By not considering alternatives to existing FITs adopted by the Commission, the Commission is not doing its due diligence in the process of working to create a new Community Solar program. Relying on existing programs that can be characterized as having lackluster results at best while ignoring flourishing FITs in municipal utility or CCA service territories, is not an effective way to implement AB 2316. In our original proposal from April 2023, the Clean Coalition referenced two FITs worth modeling a new program on, the LADWP FIT+[18] and a FIT the Clean Coalition designed for the City of San Diego.[19] The FIT+ has resulted in over 100 MW worth of projects **in service** (not just projects with executed contracts) with pricing between $0.135-$0.145/kWh. The program values reliability benefits through proper compensation for solar+storage deployments and has tiered pricing for differently sized projects.

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[18] https://www.ladwp.com/ladwp/faces/wcnav_externalId/r-gg-rs-fit?_afrWindowId=s67csbit7_1&_afrLoop=1252618308694249&_a%29%29=&_afrWindowMode=0&_adf.ctrl-state=s67csbit7_4

[19] https://clean-coalition.org/wp-content/uploads/2019/09/San-Diego-Final-FIT-Design-Recommendations-31_wb-9-Sep-2019.pdf

Total = 185 MW		
In-Service 102.2 MW	Active 77.4 MW	Available 55.3 MW

Updated as of 9/14/2023

FiT Pricing Table			
Project Capacity	In-Basin Projects		Owens Valley Projects
	Solar PV	Non-PV	Solar PV
30 kW - 500 kW	14.5¢ per kWh	11.5¢ per kWh	11.5¢ per kWh
> 500 kW - 3 MW	14.0¢ per kWh	11.0¢ per kWh	Not Available
> 3 MW	13.5¢ per kWh	10.5¢ per kWh	Not Available

Pricing for LAWDP's FIT+

The FIT that the Clean Coalition designed for the City of San Diego in 2019 takes advantage of the substantial solar siting opportunity for projects in the built environment. With base pricing of $0.08-$0.11/kWh, the FIT also includes a Built Environment Adder (for projects deployed on a rooftop, parking lot, or parking structure), a Small Project Adder (for projects less than or equal to 350 kW), a Community Benefit Adder (for projects deployed in a DAC), and a Dispatchability Adder (for projects with paired storage). The designs of both the San Diego FIT and the LADWP FIT+ are far more appropriate for Community Solar projects than ReMAT and SOC in terms of effective pricing and streamlined requirements needed to enable successful project deployments. For example, the FIT+ lists standardized fees that an applicant will be responsible for at each step of the process, increasing certainty by allowing developers to factor application/study costs into initial economic forecasting done to determine whether applying is a worthwhile investment.

Fee Schedule			
Item	Amount	Refund Policy	Additional Notes
Stand-Alone Integration Study ≤ 500 kW (Optional)	$1,000 per project	Non-refundable	If Applicant wishes to proceed, fee will be credited to 50% of the FiT Application fee.
Stand-Alone Integration Study 501 kW – 3 MW (Optional)	$2,000 per project	Non-refundable	If Applicant wishes to proceed, fee will be credited to 50% of the FiT Application fee.
Stand-Alone Integration Study > 3 MW (Optional)	$3,250 per project	Non-refundable	If Applicant wishes to proceed, fee will be credited to 50% of the FiT Application fee.
Application Fee (30 kW - 500 kW)	$500 per project	Non-refundable	Due at time of application.
Application Fee (> 500 kW – 3 MW)	$1,000 per project	Non-refundable	Due at time of application.
Application Fee (> 3 MW – 10 MW)	$1,500 per project	Non-refundable	Due at time of application.
Integration Study Fee (30 kW - 500 kW)	$750 per project	Non-refundable	Due at time of application.
Integration Study Fee (> 500 kW – 3 MW)	$1,500 per project	Non-refundable	Due at time of application.
Integration Study Fee (> 3 MW – 10 MW)	$2,500 per project	Non-refundable	Due at time of application.
Interconnection Study Fee	$1,500 per project	Non-refundable	Due at time of application.
FiT Development Security Deposit	$50 per kW	Refundable upon reaching COD	Due twenty (20) Business Days following notification of interconnection cost estimates.
10% of Estimated Interconnection Costs	TBD	Non-refundable	Due twenty (20) Business Days following notification of interconnection cost estimates.
Balance of Estimated Interconnection Costs	TBD	Non-refundable	Due six (6) months after SOPPA execution.

LADWP FIT+ standard fees

On the contrary, FITs like ReMAT and the SOC that do not provide any certitude about development costs/timelines eliminate the possibility of streamlined deployments and reduce the pool of developers interested in applying.

As proposed in this proceeding[20], the Clean Coalition's FIT includes a proximity requirement, auto-enrollment of customers, streamlined interconnection, and adders for deployments of storage. Each of these facets are critical to the creation of a successful Community Solar program. Unfortunately, of these four features, the PD only addresses auto-enrollment. While this is a step in the right direction, auto-enrollment is not enough to lead to project deployments when the rest of the proposed FITs are deeply flawed. We urge the Commission to reconsider the PD, eliminate the use of ReMAT and the SOC, take a deeper look at the Clean Coalition's original FIT proposal, and fully compensate infill projects for the value created.

VII. CONCLUSION

The Clean Coalition respectfully submits these comments on the PD and urges the Commission to reject the PD as currently written. The use of ReMAT and the SOC for underlying compensation will guarantee that the Community Solar market in California does not mature and will fail to effectively serve low-income populations in a robust manner.

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Dated: March 25, 2024

[20] See the Clean Coalition's February 27, 2023, FIT presentation.

Appendix A

Findings of Fact

1. In evaluating any existing, modified, or new Green Access Program tariff, the Commission determines if the program meets the following goals: (1) efficiently serves distinct customer groups; (2) minimizes duplicative offerings; and (3) promotes robust participation by low-income customers.

2. When a Green Access Program tariff does not meet the goals provided in Pub. Util. Code Section 769.3(b)(1)(B), Pub. Util. Code Section 769.3 authorizes the Commission to terminate or modify the tariff.

3. Whether a program "efficiently serves" distinct customer groups is evaluated by balancing sufficient enrollment by customer groups with a program's overall customer costs.

4. Whether a program "minimizes duplicative offerings" is defined as whether a program offering overlaps with similar offerings to the same customer groups.

5. Whether a program "promotes robust participation by low-income customers" is measured by the number of enrolled low-income customers for existing programs, and the number of prospective low-income customers for new programs.

6. Pub. Util. Code Section 769.3(c) establishes the requirements for new Green Access Program tariffs.

7. The current ECR program fails to efficiently serve distinct customer groups because, among other reasons, the investor-owned utilities' programs have had no customer enrollment since the programs' inception. The current ECR program fails to promote robust participation among low-income customers based on the lack of enrollment by low-income customers.

8. The current GT program fails to efficiently serve distinct customer groups because, among other reasons, the investor-owned utilities' programs have all been suspended in some capacity. The current GT program fails to promote robust participation among low-income customers based on the lack of enrollment by low-income customers.

9. The current DAC-GT program fails to efficiently serve distinct customer groups because, among other reasons, the program is under-subscribed and under-procured. The current DAC-GT program fails to promote robust participation among low-income customers based on the low level of enrollment among low-income customers.

10. The current CSGT program fails to efficiently serve distinct customer groups because, among other reasons, there have been no customers enrolled in the CSGT program since the program's inception. The current CSGT program fails to promote robust participation among low-income customers based on the lack of enrollment by low-income customers.

11. Under the Federal Power Act, FERC has exclusive jurisdiction over the sale of electricity at wholesale rates, and states are preempted from setting wholesale rates.

12. PURPA creates an exception allowing states to set wholesale rates for utilities to purchase electricity and capacity from qualifying facilities at their avoided cost.

13. FERC mandates certain minimum requirements governing how to calculate avoided cost, but states implementing PURPA-compliant programs have discretion to determine how avoided cost is calculated.

14. The NVBT proposals do not equate to retail rate programs ~~but instead resemble wholesale electricity procurement.~~

15. ~~Although p~~Proceeds of the sale of electricity purchased by the utility would be distributed to subscribers as credits in the NVBT proposals~~, this would not change the wholesale nature of the projects' delivery to the grid~~.

16. Electricity generated by proposed NVBT projects correspond ~~would have no relationship~~ with the subscriber load ~~but, rather, would be resold by the utility to end-users alongside electricity purchased in the wholesale market~~.

17. The NVBT proposals are not measurably different from the net energy metering/net billing or VNEM/net billing frameworks adopted in D.22-12-056 or D.23-11-068.

18. The NVBT proposals lack a true-up period, have no provision for surplus compensation, and can include generation ~~located offsite from subscribers and not~~ proximate to subscriber load with a requirement to be deployed in the same distribution area as subscribers.

19. ~~The NVBT proposals depict wholesale procurement and not retail net energy metering in terms of: (1) the lack of a true-up period; (2) the practice of banking surplus energy in lieu of providing net surplus energy compensation; and (3) the absence of geographic proximity between generation and subscriber load.~~

20. The structure of the NVBT proposals does not represent~~s~~ a departure from FERC precedent in the context of net energy metering and has been allowed in other states.

21. The NVBT proposals lack a true-up period to determine if there has been generation in excess of subscriber load, which is referred to as net surplus generation.

22. The NVBT proposals monthly netting of credits include indefinite rollover of credits instead of the annual true-up required in net billing and virtual net billing.

23. The NVBT proposals prohibit the generating account from distributing subscriber credits beyond the value of the generator's production to the grid or taking any bill credit for the generator's production.

24. The NVBT proposals' bill credits for any generation produced to the grid beyond that subscribed to customer accounts can be "banked" (for up to two years) until a new customer is enrolled to receive the bill credit; after two years, the bill credit would disappear.

25. The NVBT proposals do not provide generators with "net surplus compensation" — at a price equal to utility's avoided cost as required PURPA — for any net surplus generation exported to the grid in excess of subscriber load.

26. ~~Net surplus compensation is an essential feature of the Commission's net billing and virtual net billing tariffs that make them compliant with PURPA.~~

27. The Commission's use of the net compensation framework for ~~all~~ existing net metering tariffs is guided by FERC, AB 920, and prior Commission decisions, with respect to net surplus compensation.

28. AB 920 requires the Commission to establish a net surplus compensation program to compensate net energy metering customers for electricity produced in excess of on-site load at the end of a 12-month true-up period.

29. ~~The NVBT's proposed banking of credits precludes any excess generation from being compensated at the utility's avoided cost as required by PURPA.~~

30. The NVBT proposals allow generation to be located off-site from the subscriber's load~~, which is a departure from FERC precedent finding net metered generation subject to state and not federal jurisdiction~~.

31. The off-site feature of the NVBT proposals is the only way that a project is ~~make potential projects~~ comparable to the generation projects currently compensated under the Standard-Offer-Contract or participating in the ReMAT program. Project size, requirements, compensation, value creation, and customers served are all different.

32. Under 16 U.S.C. Section 2621(d)(11), net energy metering is described as service to an electric consumer, under which electric energy generated by that consumer is from an eligible on-site generation facility.

33. ~~FERC has consistently premised its decisions on the idea that acceptable net energy metering programs place the generator on-site of the load.~~

34. ~~FERC decisions finding net metering arrangements to be outside FERC's jurisdiction have involved generation located on-site to the utility customer.~~

35. Parties to this proceeding have not identified ~~no~~ authority from FERC or a federal court indicating generation for facilities to which end-use customers subscribe~~, that are not located on-site to those customers,~~ would be not considered net metering ~~and, therefore, exempt from FERC jurisdiction~~.

36. The "essential" features of net energy metering are a tariff in which a subscriber's energy generation is netted against their load within an established billing period and the subscriber's net surplus energy generation and unsubscribed generation are calculated over a true-up period, recognized as a wholesale transaction, and compensated at ~~the utility's PURPA-compliant~~ avoided costs.

37. ~~The essential features of net energy metering are lacking from the NVBT proposals.~~

38. Proponents of the NVBT proposals have ~~not~~ demonstrated that the NVBT proposals comply with federal law.

39. NVBT proposals ~~do not~~ propose a form of "net energy metering" and are ~~not~~ exempt from the requirements of PURPA on this basis.

40. Section 769.3(b)(2)(B) contains the following language: "If the commission establishes a community renewable energy program pursuant to subparagraph (A)."

41. The plain language of AB 2316 and Pub. Util. Code Section 769.3 allows the Commission to make its own determination on the reasonableness of adopting and implementing a community renewable energy program.

42. Because the NVBT proposals would compensate generators and customers based on the Avoided Cost Calculator values and not the required PURPA avoided costs, adopting any of the NVBT proposals would result in ratepayers paying ~~more than~~ the avoided costs for these resources.

43. With a proximity requirement ~~Absent project citing requirements, beyond being in the same service territory as the subscribers~~, the Commission ~~is unable to~~ can determine whether a project would avoid ~~any~~ transmission ~~or~~ and distribution costs~~, much less what that avoided costs equals~~.

44. ~~Without the certainty that the NVBT resources would be located close to customers, t~~The avoided costs of transmission and distribution ~~cannot~~ can be confirmed.

45. ~~Without Utilities' ability to~~ If an LSE cannot claim Resource Adequacy credits, NVBT projects ~~cannot~~ can avoid generation capacity costs via reduced Resource Adequacy obligations from the California Energy Commission.

46. The ~~lack of~~ requirement for a deliverability study, ~~required in the Resource Adequacy process, could lead to the need for transmission upgrades that could result in higher costs for all ratepayers~~ will lead to higher project failure rates.

47. In the VNEM, NEMA, and RES-BCT tariffs, the generator is sized to fit the load; in the NVBT proposals the customer subscriptions are sized to fit the production of the generator.

48. For both the VNEM and NEMA tariffs, the generating facility is located onsite, or on a contiguous property; whereas, with the NVBT, the generating facility ~~will~~ may be located anywhere within a utility's service territory. A proximity requirement, as proposed by the Clean Coalition, will solve this issue.

49. The proposed NVBT does not have a proximate connection between the location of the generating facility and the subscribers in the proposed NVBT. A modification will change this.

50. The NVBT proposals are ~~not functionally~~ the same as the VNEM, NEMA, and RES-BCT tariffs in that the NVBT ~~does not~~ similarly avoids transmission and distribution costs.

51. Front-of-the-meter resources are in front of a customer's meter.

52. Behind-the-meter resources are behind a customer's meter and will address onsite load, if any, and then feed back into the grid.

53. If a resource is behind the meter then the resource will offset any load from the customer before producing energy to the distribution grid.

54. ~~If the resource is in front of the meter, a customer's load may not be offset. Instead, the energy will be sent directly to the distribution grid.~~ In both cases, electricity exported to the grid will serve the nearby loads. The location of the resource and its proximity to customers will determine what happens to the produced energy. Autoenrollment can ensure projects have a proximity to subscribers.

55. The Avoided Cost Calculator and, therefore, the RIM test results should ~~not~~ be relied upon to determine the impact of NVBT proposals on nonparticipating customers.

56. Comparing wholesale procured resources with ~~the proposed NVBT~~ distributed energy resources is not how the Commission has historically evaluated distributed energy resources.

57. The NVBT proposals would not result in ratepayers compensating customers for costs that are not avoided, which would not result in a cost shift.

58. ~~Neither t~~ The plain language in AB 2316 ~~nor~~ and in Pub. Util. Code Section 769.3 ~~uses the term~~ is understood to refer to California's Avoided Cost Calculator.

59. ~~A reasonable interpretation of the term "avoided costs" in Pub. Util. Code Section 769.3 could refer to either the PURPA avoided costs or the avoided costs in the Avoided Cost Calculator.~~

60. ~~Pub. Util. Code Section 769.3 makes no requirement to use the Avoided Cost Calculator or any other specific method.~~

61. Pub. Util. Code Section 769.3 requires the use of a Commission method of calculating the avoided cost, which refers to the Avoided Cost Calculator.

62. FERC has issued guidance on how to calculate avoided cost but allows state discretion to determine how avoided cost is calculated, which does not ~~would~~ equate to the Commission's methods for calculating avoided costs in this context.

63. ~~Because none of the NVBT proposals propose a form of "net energy metering," and are not exempt from the requirements of PURPA on this basis, the Commission must turn to the PURPA guidance for calculating avoided cost.~~

64. The record indicates strong support for the adoption of a new community renewable energy program from a diverse array of entities. These entities support adoption of NVBT, not just any community renewable energy program.

65. The Commission twice set aside submission of the record of this proceeding because of concerns with NVBT proposals regarding cost effectiveness and reliability matters; SCE's PURPA compliant proposal is an inadequate ~~alternative~~ community renewable energy program ~~to address these concerns~~ that does not provide the same level of detail as the NVBT and was proposed in the very last round of comments setting aside the record.

66. ~~All parties~~ Parties have not been provided with an adequate opportunity to comment on SCE's PURPA compliant proposal given the amount of time spent debating the NVBT.

67. Pub. Util. Code Section 769.3 does not require the community renewable energy program to attain any specific procurement target. This does not mean that a new community renewable energy program should be used as a tool to achieve legislatively mandated procurement targets for other unique programs. A new program should help achieve SB 100 targets.

68. Pub. Util. Code Section 769.3 requires the Commission to determine by March 31, 2024, whether it is beneficial to adopt a community renewable energy program.

69. SCE's PURPA compliant proposal is ~~neither~~ out of scope ~~nor does it~~ and violates due process rights.

70. SCE provides no analysis that its PURPA compliant proposal would comply with Pub. Util. Code Section 769.3(c)(1) or Pub. Util. Code Section 769.3(c)(6).

71. The Energy Commission will decide whether a proposal complies with Section 769.3(c)(1).

72. Pub. Util. Code Section 769.3(c)(1) directs that "[f]or purposes of this paragraph, the Commission shall consult with the Energy Commission."

73. In SCE's PURPA compliant proposal, the subscribing customer's share of the generation resource's compensation would be set aside in a balancing account and distributed through a flat $/kWh credit that can be trued-up annually based on facility performance and credits distributed; the credit is deducted from compensation to the generation, which is calculated based on PURPA avoided costs of the program's facilities.

74. SCE has presented limited evidence on how its PURPA compliant proposal meets the requirements of Pub. Util. Code Section 769.3(c)(3) and Green Access Program tariff evaluation results indicate there has been limited success developing community solar.

75. The limited past success was one of the reasons for requiring an evaluation of the Green Access Program tariffs and the subsequent required applications for improvement filed as the basis of this proceeding.

76. PURPA prices alone ~~may~~ will not be sufficient compensation for garnering additional interest in community solar by developers.

77. The SCE PURPA compliant proposal is incomplete.

78. The incomplete SCE PURPA compliant proposal cannot lead to the development of a successful Community Solar market in California.~~requires additional record building time that the Commission does not have.~~

79. The Commission has several existing tariffs that are PURPA compliant. None have been successful, and none are sufficient as base pricing for a new community renewable energy program.

80. It is unreasonable to address the concern that PURPA avoided costs may be insufficient by using the $33 million appropriated to the Commission for community solar usage as an adder. Adding funds to a failed program without major changes to the underlying programmatic requirements is not enough to make the program successful. $33 million is not enough to help the Community Solar market in California flourish.

81. In Pub. Util. Code Section 769.3, the Legislature intended low-income households and those who rent or lease their space to be the target market for the community renewable energy programs.

82. Only low-income households are eligible for the $33 million funds appropriated to the Commission through AB 102.

83. The Commission adopted automatic enrollment in DAC-GT in D.20-07-008.

84. Automatic enrollment reduces administrative costs, minimizes marketing, education, and outreach costs, and reduces barriers to access.

85. Compensating customers in energy units is not applicable when netting is not being performed.

86. Limiting the size of PURPA-compliant community renewable energy program projects to 20 MW and requiring developers to demonstrate to the Energy Commission that a project complies with Section 10-115 of the California Building Code ensures compliance with Pub. Util. Code Section 769.3(c)(1).

87. Requiring that 51 percent of a ~~PURPA-compliant~~ community renewable energy program generation facility's capacity be subscribed to low-income households ensures compliance with Pub. Util. Code Section 769.3(c)(2).

88. A feed-in tariff is a standardized, long-term, guaranteed contract that allows smaller local renewable energy projects to sell power to the local utility or other load-serving entity. Market-based, cost-effective FITs with streamlined interconnection allow local businesses, residents, and organizations to install clean local energy projects in underutilized spaces such as rooftops, parking lots, parking structures. ~~Requiring the PURPA-compliant community renewable energy program to use PURPA avoided costs to compensate generation resources ensures program costs are not paid by nonparticipating customers in excess of avoided costs~~.

89. Requiring the ~~PURPA-compliant~~ community renewable energy program project developers to comply with the prevailing wage requirement ensures compliance with Section 1773 of the Labor Code and Pub. Util. Code Section 769.3(c)(4).

90. ~~Requiring the PURPA-compliant community renewable energy program to: (1) compensate generating resources based on the PURPA avoided costs of the facility and (2) provide subscribing customers with their portion of this compensation as a bill credit results in compliance with Pub. Util. Code Section 769.3.(c)(3) and (c)(5).~~ A well-designed feed-in-tariff offer clear guidance to the market through predefined terms and prices, thereby allowing project

developers to qualify their planned projects before undertaking significant investment in siting, RFO processes, or interconnection.

91. There are several state and federal funding sources available for ~~PURPA-compliant~~ community renewable energy programs AB 102, the Environmental Protection Agency's Solar for All, the enhanced federal ITC, and the Greenhouse Gas Reduction Fund.

92. Requiring developers of community renewable energy program projects to take advantage of the available state and federal funding results in compliance with Pub. Util. Code Section 769.3(c)(6).

93. The results of the evaluation above and the record of this proceeding indicate the need for improvement in the existing Green Access Program tariffs.

94. The original intention of the filing of the applications in this proceeding was to review and improve the Green Access Program tariffs.

95. Challenges to attracting customers and developers in the Green Access Program tariffs emanate from enrollment rate, eligibility requirements, rate volatility, and duplication.

96. Voluntary inclusion of storage will likely result in more costly projects, but this cost is balanced with the additional value to the grid that resources combined with storage will provide. A voluntary option for standalone storage will maximize the benefits to the ratepayers and reduce costs for developers.

97. California Air Resources Board VRE programs are costly and should be eliminated.

98. Validation and tracking by program administrators on a single website is a more cost-effective method of verification and is consistent with prior Commission directives.

99. It is efficient to combine the unprocured capacity of the CSGT and DAC-GT, transition customers on the existing CSGT to the modified DAC-GT, allow the enrollment of previously wait-listed customers, and focus on improving future enrollment of low-income customers.

100. Requiring projects to be sited in the top quarter of disadvantaged communities within the service territory of the respective utility or CCA has led to fewer projects being eligible for the DAC-GT.

101. An objective of DAC-GT is to promote robust participation by low-income customers, i.e., provide for increased access to renewable energy by challenged communities

102. Expanding the DAC-GT site requirements to allow eligible projects to be located no more than five miles from one of the top 25 percent of disadvantaged communities will help to meet the objective of promoting robust participation by low-income customers.

103. The "top off" approach would have negative impacts on nonparticipating ratepayers.

104. PG&E has adopted auto-enrollment in the DAC-GT for customers at high risk of disconnection.

105. The Commission has adopted the practice of customer self-certification in other public purpose programs.

106. Adopting the auto-enrollment practice adopted by the Commission in D.20-07-008 for use in the modified DAC-GT is efficient and will improve the current enrollment statistics for low-income customers.

107. SCE's most recent Green Tariff contract was executed in 2016.

108. A current cost containment cap reflects current market prices and developer costs.

109. The record does not contain any proposal for the process to update the cost containment cap.

110. Revising the submission date of the DAC-GT Program Administrator's annual budget advice letter to April 1st will not impact the timing of the Energy Resource Recovery Account proceedings and will provide additional time to ensure accuracy of the costs.

111. Resolution E-5124 required PG&E to provide in their 2022 Budget Advice Letter a discussion on its efforts to eliminate manual data transfers between PG&E and participating CCAs.

112. While PG&E stated it would evaluate the costs and benefits of implementing a billing solution, the Commission has not seen a comprehensive analysis.

113. Because customers are eligible to be enrolled in DAC-GT and CSGT for up to 20 years, it is prudent to consider the costs and benefits of implementing an automated billing solution for DAC-GT and CSGT customers.

114. The following improvements will lead to potential enrollment increases in the modified DAC-GT, thus addressing the Pub. Util. Code Section 769.3 goal of promoting robust participation by low-income customers: (1) move legacy CSGT projects to the modified DAC-GT; (2) transfer previously enrolled utility or CCA customers to the modified DAC-GT; and (3) increase the cap of each Program Administrator that is close to being fully procured within a particular utility service territory to allow enrollment of an additional 50 percent of eligible customers.

115. SDG&E's small customer base may not support participation in Green Access Program tariffs and could result in the small volume of bundled customers being unfairly burdened by the costs associated with the Green Access Program tariffs.

116. The DAC-GT and CSGT Process Evaluation report recommends the Commission decrease the frequency of solicitations to once a year in order for the solicitations to be more efficient and to be on a more predictable schedule that allows time for developers to prepare and submit offers.

117. A tariff sunset for DAC-GT is not needed to provide~~s~~ clarity to subscribers.

118. The PG&E proposed use of RPS resources to bridge capacity shortfalls does not indicate when PG&E should buy versus procure additional resources.

119. The ECR tariff has experienced low-enrollment and fails to efficiently serve any distinct customer group.

120. Due to a decrease in rates at the end of December 2020, participating Green Tariff customers experienced an increase in their bill credits, which created a surge in enrollments to the tariff leading to more customers.

121. Integrating Green Tariff resource availability with other Integrated Resource plans could lead to less rate volatility.

122. All costs for the modified Green Tariff are borne by the participating subscribers.

123. A program that is overly complicated or with insufficient base compensation will not garner interest from developers or result in successful deployments, even with additional available funds.

124. Infill solar projects provide greater level of benefits than non-infill projects and should be compensated appropriately for the value created. An example of this value is avoiding transmission and distribution infrastructure, setting the stage for community resilience, and increased reliability.

125. The IOUs should do not have any infill projects in their portfolio. Subscribers of infill projects deployed under a new community renewable energy program should not be charged the Power Charge Indifference Adjustment.

Conclusions of Law

1. A community renewable energy program is adopted and shall contain the following elements:

(a) Foundational Tariff — Selection of one of the ~~existing tariffs that are compliant with the federal Public Utility Regulatory Policies Act including, but not limited to, the Renewable Market Adjusting Tariff (ReMAT) and Standard-Offer-Contract. Developers shall adhere to the previously adopted tariff rules for the selected foundational tariff.~~ Feed-In-Tariff designed on the Clean Coalition's City of San Diego Feed-In-Tariff and the Los Angeles Department of Water and Power Feed-In-Tarff+ program.

(b) Subscription Model and Bill Credit — Subscribing customers will receive a flat monetary credit on their monthly bill based on a percentage of each project's overall revenue share paid for through external funding or incentives. Low-income customers, as defined in Public Utilities (Pub. Util.) Code Section 769.3 will receive no less than 20 percent. The bill credit will be reviewed on an annual basis and updated through a true-up process.

(c) Adder for low-income customers — A fund of monies will be kept in a balancing account and will be provided to eligible low-income subscribers. Incentive levels will be dependent upon the amount of funds in the balancing account, including new funds when they become available.

(d) Eligibility Requirements — All customers will be eligible to enroll as subscribers in this tariff.

(e) Automatic Enrollment — Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall implement the same auto-enrollment procedures as approved by the Commission in Decision 20-07-008 and Resolution E-5124.

(f) Compliance with Pub. Util. Code Section 769.3(c)(1) — In addition to the requirements of the foundational tariff and the subscription model, the community renewable energy program tariff shall require that: (1) developers demonstrate to the California Energy Commission that the proposal complies with Section 10-115 of the California Building Code; and (2) all projects shall be limited to 20 megawatts.

(g) Compliance with Pub. Util. Code Section 769.3(c)(2) — In addition to the requirements of the foundational tariff and the subscription model, the community renewable energy program tariff shall require that developers demonstrate that 51 percent of a project's capacity is subscribed to low-income customers.

(h) Compliance with Pub. Util. Code Section 769.3(c)(4) — In addition to the requirements of the foundational tariff and the subscription model, the community renewable energy program tariff shall require that developers demonstrate that all projects shall comply with the prevailing wage requirement.

2. The Community Solar Green Tariff (CSGT) is discontinued. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (collectively, Utilities) and Community Choice Aggregators (CCAs) shall transfer all remaining un-procured capacity assigned to this tariff to the modified Disadvantaged Communities Green Tariff (DAC-GT). Utilities and CCAs may transition customers currently enrolled in CSGT into the modified DAC-GT, unless there is no remaining capacity. If capacity is at subscription maximum, Utilities and CCAs may submit a Tier 1 Advice Letter to the Commission for approval of additional capacity to ensure that no low-income customer loses their discount. ~~are responsible for informing the customer of the loss of their discount.~~
3. The Disadvantaged Communities Green Tariff shall be modified as follows:

(a) Site requirements are revised to allow eligible projects to be located no more than five miles from eligible disadvantaged communities census tracts.

(b) Pacific Gas and Electric Company, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company shall implement automatic enrollment as previously adopted in Decision 20-07-008 and reiterated in Resolution E-5124.

(c) SDG&E is permitted to terminate its tariff to its bundled customers but must continue its cooperation with any Community Choice Aggregator that seeks to offer the tariff in its territory by including a proposed venue in which to seek cost recovery in the Tier 2 Advice Letter required by Ordering Paragraph 9. The Community Choice Aggregator may choose to absorb any remaining available capacity from SDG&E's original programs.

(d) Capacity is increased by an additional ~~37.316~~ 200 megawatts of additional capacity.

(e) The capacity cap of each Program Administrator, who is close to being fully procured within a particular utility service territory, is increased to allow the enrollment of an additional 50 percent of eligible customers.

(f) Solicitations are decreased to a minimum of once a year.

(g) The auto-enrollment process, as adopted in Decision 20-07-008 and modified in Resolution E-5124, shall be implemented.

(h) The cost containment cap shall be updated using the steps in Ordering Paragraph 4.

(i) The submission date of the DAC-GT Program Administrator's annual budget advice letter is changed to April 1st.

(j) A sunset for the tariff is adopted whereby when the remaining capacity for the modified tariff reaches 500 kilowatts or there has been no participation by developers in two consecutive solicitations, a utility shall submit a Tier 1 Advice Letter informing the Commission that solicitations have been suspended.

4. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) shall work together to develop a proposal for updating the cost containment cap for the Disadvantaged Communities Green Tariff. No later than 90 days from the adoption of this decision, PG&E and SCE shall submit a Tier 2 Advice Letter proposing a method for updating the cost containment cap.
5. The Green Tariff shall be modified as follows:

(a) Eligibility is aimed at market rate customers and all costs shall be recovered by participating customer subscribers.

(b) The Green Tariff Shared Renewables enhanced community renewables (GTSR-ECR) option is discontinued for new projects. The unprocured capacity for this option is reassigned to the modified Green Tariff, creating a cap of 562 megawatts (MW) statewide. Southern California Edison Company (SCE) may eliminate the one-sixth residential requirement.

(c) Projects are capped at 40 MW. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company may request to increase these caps through a Tier 2 Advice Letter.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Program Administrators of tariffs in the California Renewable Energy Portfolio shall conduct data collection and reporting on program

operation and outcomes for public posting on the California Distributed Generation Statistics (DGStats) website. This directive replaces reporting requirements in Decision (D.) 18-06-027, Resolution E-4999, D.21-12-036 and Resolution E-5028. Specific program metrics, such as projects approved and completed, project status and capacity, location of project, subscriber information, job training, local hiring, and coordination with low-income and clean energy programs shall be posted on the DGStats website, or another website as determined by the Energy Division, on a quarterly basis. The data shall be uniformly formatted and contain no confidential material. Energy Division is authorized to modify these reporting requirements as needed to inform evaluation, measurement, and verification activities.

7. No later than 60 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, and participating Community Choice Aggregators shall facilitate a workshop with Energy Division, parties to this proceeding, and other relevant stakeholders to determine the format and specific data to be included in the California Distributed Generation Statistics website reporting, as directed by Ordering Paragraph 6 above.
8. No later than 45 days after facilitating the workshop, as directed by Ordering Paragraph 7 above, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, and participating Community Choice Aggregators shall submit a joint Tier 1 Advice Letter outlining what was agreed upon as well as any efforts planned to better coordinate amongst the various Program Administrators and to automate the data collection and transfer process.
9. No later than 60 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) and/or participating Community Choice Aggregators (CCAs) shall each submit a Tier 2 Advice Letter updating their Community Solar Green Tariff according to Ordering Paragraph 2, their Disadvantaged Communities Green Tariff according to Ordering Paragraph 3, and/or their Enhanced Community Renewables and Green Tariff according to Ordering Paragraph 5 above. Utilities and participating CCAs shall coordinate before submitting the advice letters to ensure uniformity, to the extent possible to ensure that tariff language is uniform across the state. The advice letter shall include details on how the tariff(s) will result in incremental new renewable energy being purchased.
10. No later than 90 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each submit a Tier 2 Advice Letter proposing tariff language for the community renewable energy program, as set forth in this decision, and adopted in Ordering Paragraph 1 above. The tariff language shall list any additional supply-side tariffs applicable for the community renewable energy program. The advice letters shall align tariff language across the three utilities.
11. No later than 60 days of the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (collectively, Utilities) shall establish a balancing account to track the subscriber revenue

shares and distribute the appropriate shares through the bill credit described in Ordering Paragraph 1 above. Utilities shall also use this balancing account to receive and track external funds to supplement eligible projects through the community renewable energy program low-income adder.

12. In its next Tier 2 Disadvantaged Community Green Tariff (DAC-GT) and Green Tariff programs Annual Budget Advice Letter, required by Resolution E-4999 and due on February 1, 2025, Pacific Gas and Electric Company (PG&E) shall provide a detailed scope and cost estimate of developing a fully automated billing solution for Community Choice Aggregator customers enrolled in the modified DAC-GT and Green Tariff. The proposed billing solution shall follow the same billing process that is provided to participating PG&E customers. The filing shall also describe how PG&E's billing implementation efforts here would be integrated into PG&E's ongoing billing system upgrades.
13. Energy Division is authorized to hire a consultant to develop a statewide website for the Commission's portfolio of renewable energy programs adopted in this decision, subject to budget appropriation. The objective of the website is to assist in overcoming barriers in customer and project developer awareness of the tariffs in the portfolio. Energy Division is authorized to provide early access to a draft version of the website and related content to this service list for informal party and other stakeholder comment to ensure the webpages are clear and complete.
14. Energy Division is authorized to develop and issue a Request for Proposal for an independent consultant with expertise in evaluation methods and processes to conduct evaluations of the modified Green Tariff program and new community renewable energy program. The Disadvantaged Communities Green Tariff evaluation schedule, as ordered in Decision 18-06-027, is revised to align with the evaluations ordered here. The evaluations shall be completed, and results (including recommendations) shared with the service list no later than three years from the adoption of this decision. Parties will be provided an opportunity to comment on the results of the evaluations and potential next steps. No later than 90 days following the effective date of the contract or agreement with the selected consultant or consultants, the consultant(s) under the direction of the Energy Division, should facilitate a workshop with parties to discuss the objectives, methodology, and metrics for the evaluations.
15. Application (A.) 22-05-022, A.22-05-023, and A.22-05-024 remain open to address further implementation issues related to the California Shared Renewables Portfolio of tariffs.