Docket No.: A.22-05-022, A. 22-05-023, A. 22-05-024

Exhibit No.: CLC-2

Date: April 7, 2023

Witness: Ben Schwartz

PREPARED REBUTTAL TESTIMONY OF BEN SCHWARTZ ON BEHALF OF THE CLEAN COALITION

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I. INTRODUCTION

Pursuant to Commissioner Reynolds' Scoping Memo and the Administrate Law Judges' Amended Schedule, the Clean Coalition submits this rebuttal testimony offering support for the Coalition for Community Solar Access's Net Value Billing Tariff and differentiating tariff structure and billing changes from solutions that are necessary to improve the procurement process.

II. STATEMENT OF QUALIFICATIONS

Q: Please state your name, position, and business address for the record.

A: My name is Ben Schwartz. I am policy manager for the Clean Coalition, a 501(c)(3) non-profit. My business address is 1800 Garden Street, Santa Barbara, CA 93101.

Q: Please describe your professional background.

A: I graduated from UCSB 2020 with a b.a. in History of Public Policy and Environmental Studies. I began my work with the Clean Coalition before graduating from university, starting full time as a policy associate in the summer of 2020 and receiving the title of Policy Manager during the winter of 2020. I oversee all of the Clean Coalition's regulatory work the Clean Coalition and have intervened on behalf of the Clean Coalition at the California Independent System Operator ("CAISO"), the California Air Resources Board ("CARB"), the California Public Utilities Commission (the "Commission"), the California Energy Commission ("CEC"), and the Federal Energy Regulatory Commission ("FERC").

Q: On whose behalf are you testifying in this proceeding.

A: I am testifying on behalf of the Clean Coalition. 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.

Q: Have you previously testified on behalf of the Clean Coalition before the California Public Utilities Commission?

A: Yes, I have testified before the California Public Utilities Commission previously, submitting opening testimony in this proceeding (A.22-05-022, A. 22-05-023, A. 22-05-024) as well as for the proceeding to developer a Net Energy Metering ("NEM") Successor Tariff, R. 20-08-020.

Q: Are the statements made in your testimony true and correct to the best of your knowledge and belief?

A: Yes, they are.

Q: To the extent that this submitted testimony contains any opinions, do they represent your best judgement as a professional?

A: Yes.

Q: Do you have anything further to state for the record?

A: No, this concludes my statement of qualifications.

III. EVALUATION OF PARTY PROPOSALS

Q: Which party proposal should the Commission adopt?

A: The Clean Coalition generally supports the Coalition for Community Solar Access's ("CCSA") Net Value Billing Tariff (NVBT) as a straightforward option to deploy solar plus storage that is valued at avoided cost export rates. The NVBT aligns well with the Net Billing Tariff recently adopted in the Net Energy Metering (R. 20-08-020) proceeding and can be administered at a lower cost than the existing Green Access Programs (GAP). While the Clean Coalition initially proposed a Feed-In-Tariff ("FIT") proposal, we did so because the based FIT rate and adders are streamlined and easy to understand for all parties involved. However, after reviewing the significant testimony prepared by CCSA, I believe that the proposed NVBT format is straightforward and can result in streamlined procurement, particularly if a few changes are included to ensure that the program is easily accessible for both developers and ratepayers.

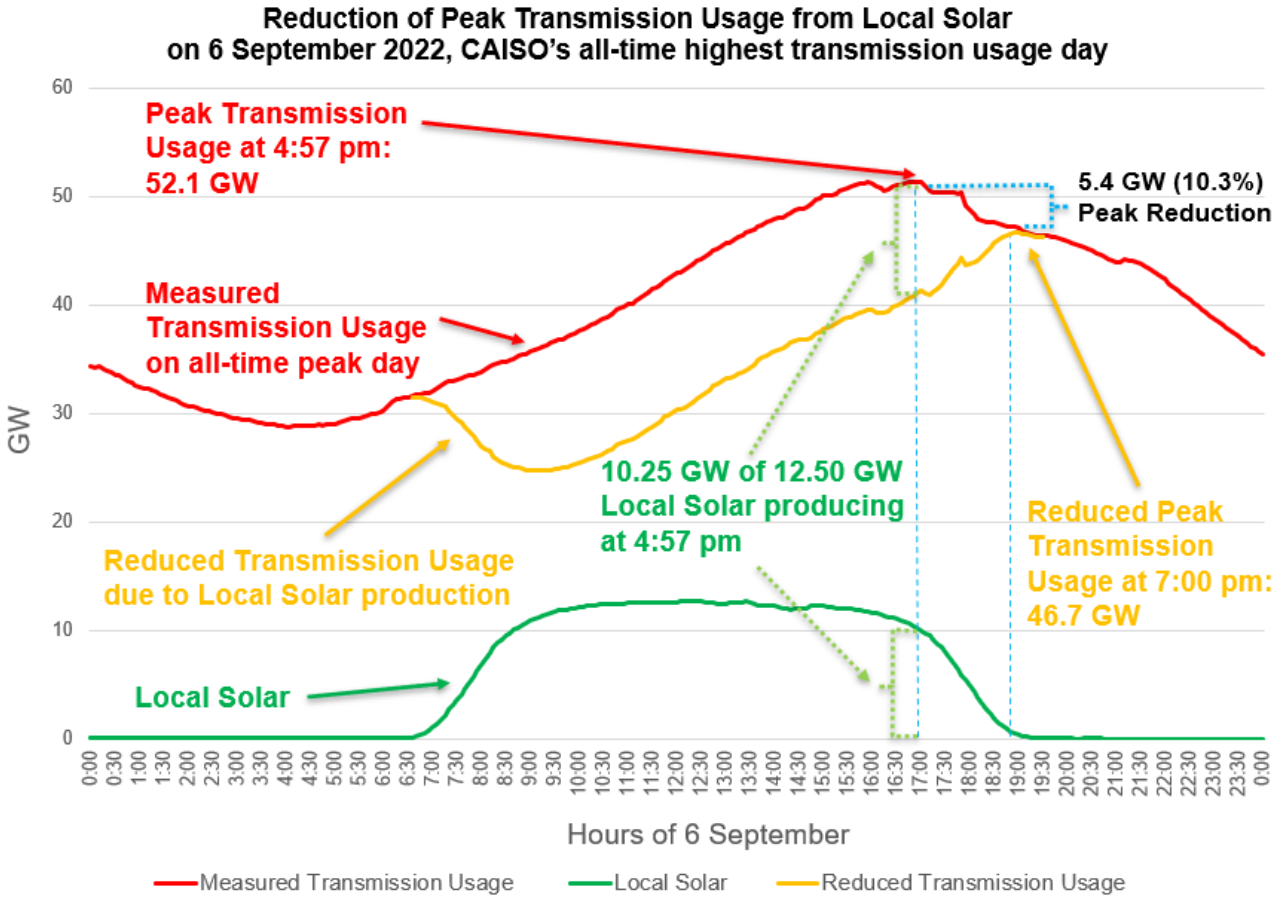
Q: What changes should be made to the NVBT?

A: In order to ensure that the avoided transmission and distribution values in the Avoided Cost Calculator are achieved through the deployment of Community Solar projects, I believe that it is essential to further restrict the definition of which customers are eligible to receive credits. CCSA's revised testimony would allow projects to be interconnected via the distribution grid and all customers withing the utility distribution company's ("UDC") to be eligible to subscribe.[1] I believe that the limit for subscribers should be either within

[1] CCSA Revised Testimony at p. 4

the same distribution area as the project itself or within five miles of the project site. This limitation ensures that the transmission system is not required to deliver energy to the end-user. As a result, each subscriber should receive credits for the portion of energy they subscribe to as well as an exemption from Transmission Access Charges ("TAC") for that percentage of imported energy. This is exemption is comparable to the Commission's determination in the Net Energy Metering proceeding that transmission costs should not be included in a nonbypassable charge or a fixed charge because energy produced under the NVBT will be delivered via the existing distribution grid without requiring the use of (or back feeding to) the transmission grid. An exemption from TAC for the percentage of subscribed energy will better harmonize the NVBT and the benefits of the Net Billing Tariff. Therefore, it is reasonable to exempt subscribers from paying TAC on community solar-imported energy.

Moreover, requiring a project to be sited closer to the subscribers it will serve makes it more likely that projects will be sited in disadvantaged communities (DACs), which aligns closely with the Commission's goals in the DER Action Plan 2.0 and the ESJ Action Plan. The NVBT will also align the GAP with Commission goals for additional dispatchable generation due to the storage requirement, greatly increasing the value each deployment will have in terms of reducing Peak Transmission Usage.



The image above shows that if the 12.5 GW of transmission-interconnected solar recorded by CAISO on 6 September 2022 had instead come from local solar (interconnected via the distribution grid), the Peak Transmission Usage on that all-time historic-peak day would have been reduced by over 10%.[2] Hence, local solar would have had a nearly 5 times greater impact in reducing peak transmission usage than the record-setting 1.2 GW of Demand Response on that day. The state needs to procure new capacity on an unprecedented scale, which will require local deployments close to load centers, where the energy can be used most efficiently. At peak times, standalone solar can reduce the peak by close to 50% of the installed capacity; when paired with storage, the peak reduction value increases to closer to 70%.[3] Importantly, the graph also shows that at the peak on 6 September 2022, which was at 4:57, around 80% of the solar was still being produced, which demonstrates that solar and solar plus storage can have significant reliability benefits. It is also worth noting that the additional components of transmission usage that are captured in wholesale prices of electricity are associated with line losses and congestion costs, and while line losses consume an average of about 10% of electricity that uses the transmission grid, the inefficiencies are far higher during peak transmission usage periods when high temperatures exacerbate line losses and congestion constraints require circuitous routing to deliver energy over the transmission grid – or require the purchase of energy from much higher cost sources that would typically be too uncompetitive to run (and usually too dirty as well). Hence, the benefits of local solar go way beyond just looking at the average costs associated with transmission usage.

Q: Are there any other exemptions from existing charges that you would recommend?

A: Due to the fact that the proposed NVBT will result in deployments of local energy without creating any costs shifts, regardless of what entity manages the program I do not believe that the PCIA should be applied to the percentage of subscribed energy. Deployments of Community Solar projects that are subscribed to by CCA customers will not result in any new costs for non-bundled customers.

IV. OTHER ESSENTIAL ASPECTS OF A SUCCESSOR TARIFF

Q: How should subscriber enrollment work under the NVBT?

A: Since the GAP are meant to ensure that customers in DACs—as well as those without access to NEM—can receive benefits from locally-sited renewable energy projects, I believe that residents from DACs located near projects should be auto enrolled in the NVBT and be provided with recommendations about the various levels of savings that are

[2] https://clean-coalition.org/news/local-solar-is-the-best-solution-for-reducing-peak-transmission-usage-and-electricity-costs-for-ratepayers/

[3] Application of Center for Biological Diversity, Protect Our Communities Foundation, and Environmental Working Group for Rehearing of Decision 22-12-056 at p. 26.

possible depending on the amount of energy that they subscribe for. The Clean Coalition's experience with the existing GAP have made it abundantly clear that ratepayers in DACs have trouble registering for the existing programs and do not necessarily trust claims about bill savings without seeing transparent and easily understandable information. While it is always beneficial to have a local Community-Based Organization ("CBO") to work with residents, auto-enrollment with clearly defined savings based on percentage of subscribed energy will simplify the process by making it easier for low-median income ("LMI") customers to realize the benefits of subscribing by removing the hassle of filling out forms.

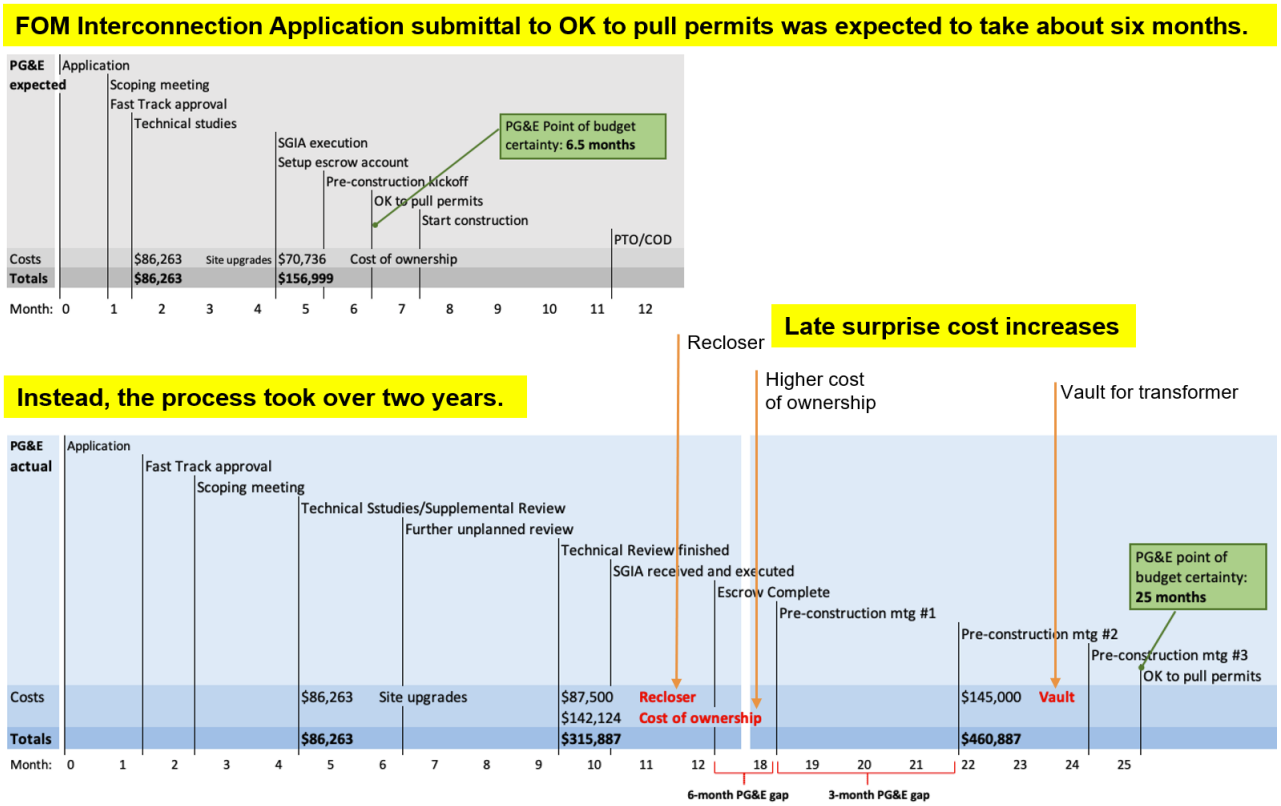
Q: Are there any other aspects of a streamlined procurement process that you would like to address here?

A: Yes, the most important aspect of a streamlined Community Solar program is ensuring that the interconnection process is determinative (e.g., a strong application with no deficiencies will result in a deployed project in a timely manner). As a result, it is necessary to address the existing interconnection process under the Wholesale Distribution Access Tariff ("WDAT"). Ideally, many, if not all projects will be able to utilize the Fast Track process, which is a smoother process than non-Fast Track WDAT interconnection. However, changes are necessary to ensure that the Fast Track process adheres to existing timelines and that non-Fast Track projects do not experience significant delays and/or surprise cost increases after the Generator Interconnection Agreement is signed.

Clean Coalition has considerable experience with the difficulties of the WDAT Interconnection process. As part of the Peninsula Advanced Energy Community (PAEC) Initiative,[4] 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. In addition, we have firsthand experience navigating the WDAT interconnection process in PG&E's service territory as part of a CEC-grant funded FOM battery energy storage project called the Valencia Gardens Energy Storage ("VGES") project. The project, was intended to increase the hosting capacity on the feeder by 25% and potentially provide resilience down the line to the low-income senior housing at the Valencia Gardens Apartment in San Francisco where it was to be sited.[5]

[4] 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)

[5] https://clean-coalition.org/wp-content/uploads/2021/05/VGES-2-page-overview-06_rf-11-May-2021.pdf https://clean-coalition.org/wp-content/uploads/2021/09/FOM-Energy-Storage-Interconnection-Case-Study.pdf



VGES expected timeline versus actual timeline

The Fast Track process, which was expected to take approximately six months ended up taking over two years, due in large part to utility delays and the fact that project costs for interconnection-related upgrades ballooned from $156,999 to $460,887. We had expected to be able to pull permits at 6 months after submitting the Interconnection Application for VGES, with a point of budget certainty at 6.5 months. However, the actual process took over two years, with a point of budget certainty at 25 months, 18.5 months after expected. Note that the Small Generator Interconnection Agreement ("SGIA") was signed at 10.5 months, yet new requirements for upgrades were added as far as 12 months after the SGIA was executed. Late surprise requirements and cost increases added to this extended timeline; for example, PG&E added a cost of ownership ("COO")—the cost for the utility to maintain and/or replace equipment as needed—which resulted in money being frozen in an escrow account and additional costs to cover tax liability for the equipment. The COO was not mentioned initially, and when it was brought up, the cost was underestimated. The same types of delays are likely to occur with GAP-interconnection applications unless a streamlined interconnection process is addressed in the decision approving a new program. For projects sized up to 1 MW, we recommend a Fixed Fee, Utility Pays ("FixUP") proposal. FixUP will allow FOM projects to determine whether they qualify for Fixed Fee interconnection based on publicly accessible eligibility criteria. The Fixed Fee is estimated at $10,000. All FOM projects that are no larger than 1 MW will avoid the bureaucratically complex and unnecessary process of having to pay for grid upgrades and

then legally deed those upgrades to the utility, as well as avoiding the need for an escrow account, which eliminates further complexities and costs. Moreover, for FOM projects that are no larger than 1 MW and that do not meet all other Fixed Fee eligibility criteria, the utility will still directly pay for any interconnection costs to streamline the interconnection process for these small FOM projects and then recover those costs based on standardized unit costs, which each utility publishes annually. The Clean Coalition estimates that FixUP will yield an average of at least per FOM project. By adopting a standard fee for projects that meet certain deterministic criteria and ensuring that the utility pays for upgrades directly, FixUP would extend the streamlined BTM interconnection processes, timing, and price certainty to small FOM projects. Other WDAT-interconnection related issues and Clean Coalition solutions can be found at the table labelled Attachment A, below. For the NVBT, or any other successor GAP to be successful, streamlined interconnection is necessary and must be clearly codified withing the program language.

V. CONCLUSION

Q: Do you have anything else to say?

A: Yes, only that we appreciate the opportunity to submit this rebuttal testimony and hope that the Commission will adopt a slightly modified version of CCSA's NVBT, with the proposed changes contained herein this testimony.

Attachment A

WDAT Interconnection Issues and Clean Coalition Solutions

Issue	Summary of issue	Solution
Delays caused by upgrade requirements	For some parts of the process, developers are currently unable to work directly with third parties to make utility upgrades; for any upgrades that the IOUs must make, developers must rely on the utility's schedule, which leads to delays.	Approve a system like the Rule 21 interconnection process, which allows utility third-party vendors approved by the utility to carry out infrastructure upgrades. (All requirements, specifications, and inspections would still be in the hands of the utility.) Allowing pre-approved developers to work directly with third parties would address the need for upgrades in a timely manner while reducing total project costs.
Confidentiality rules limit developer/utility information sharing.	IOUs consider all project-specific information confidential — even though developers do not generally request confidential status.	Offer specific details on interconnection studies to provide important information for project managers, and to foster collaboration between developers throughout an IOU service territory. **Redact information upon developer request (opt-out by default, opt-in by choice).**
Prohibitive interconnection costs can make site selection in certain areas extremely difficult.	Current project economics make interconnection costs prohibitive.	Change the methodology for allocating network upgrade costs (for DER projects providing a public good) so costs can be recovered in a similar manner to transmission interconnection upgrades. Alternately, consider a cost sharing system that spreads out costs rather than forcing one developer to shoulder the full cost burden.
Changing estimates (surprise increases) for network upgrades causes developer uncertainty.	FOM interconnection costs cannot be definitively determined or even roughly estimated prior to application from publicly available information. FOM projects also face significant delays during interconnection impact and cost responsibility studies.	Implement a cumulative cost approach, ensure the applicant receives the final design & costs early, reduce timeline gaps between SGIA/financial security deposit phase to pre-construction/permit-ready status, shorten interconnection application review process and pre-construction timelines, & the utility to begin analysis early with all subject matter experts.
Lack of access to accurate grid data	Grid upgrade costs are not transparent in advance and	Provide greater access to actionable ICA data prior to submission of an IA,

causes developer uncertainty (part 1)	can often come as a surprise, meaning a developer has to submit an application just to determine whether the cost of moving forward is reasonable.	allowing developers to determine locations where grid upgrades are not necessary or which upgrades are most cost-effective. Add to ICA maps all projects and dates in the interconnection queue to accurately represent the feeders once the projects are interconnected. Ideally, forecasted load growth data will also be added to the maps.
Lack of access to accurate grid data causes developer uncertainty (part 2)	It is not possible to conduct a full economic analysis for a potential project without accurate inputs for utility costs that are in a user-friendly form (the data needs to be easy to work with/model).	Provide on-demand/online modeling to allow applicants to optimize system size and design relative to impact mitigation costs. In the future, add information about locationally relevant utility-sponsored programs that compensates projects for providing grid services (e.g., increasing hosting capacity, voltage regulation, etc...).
Lack of project management flexibility	Personnel changes, missed internal-utility deadlines, late additions of equipment upgrades, last-minute construction changes for major equipment, delayed project schedule, a delayed engineering costing, and lengthy timelines are enough to halt a project. Deadlines need to be met.	Tighten the project management process by: • Holding bi-weekly interconnection application check-in calls from the beginning of the project with the interconnection manager assigned to the project that include all relevant parties as okayed by the customer of record. • Ensuring subject matter experts at the utility work in parallel. • Allowing the customer of record to invite all relevant parties to listen in to meetings. Typically, the utility will only speak to the customer of record or customer representative—often the subcontractor or engineering, procurement, construction (EPC).