BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

FILED
07/31/23
02:01 PM
A2205022

Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs	Application No. 22-05-022 (Filed May 31, 2022)
And Related Matters	Application 22-05-023 Application 22-05-024

OPENING COMMENTS OF THE COALITION FOR COMMUNITY SOLAR ACCESS ON ADMINISTRATIVE LAW JUDGE'S RULING SETTING ASIDE SUBMISSION OF THE RECORD TO SEEK COMMENTS ON COST-EFFECTIVENESS CONSIDERATIONS

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Dated: July 31, 2023

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Pursuant to the schedule established in the Administrative Law Judges' Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectiveness Considerations ("ALJ Ruling"), filed June 23, 2023, the Coalition for Community Solar Access ("CCSA") respectfully responds to the questions presented in the ALJ Ruling. CCSA appreciates the opportunity to supplement the record with further cost-effectiveness analysis of existing and proposed programs and related topics which further demonstrate that the Net Value Billing Tariff is the best option to meet the goals and requirements of AB 2316.

I. INTRODUCTION

Consideration of the Net Value Billing Tariff ("NVBT") comes at a time when the state faces acute electric reliability challenges. At the same time, funds are available from both the federal and state government to deploy community solar plus storage resources in the next several years at a scale that can have a meaningful impact on addressing reliability challenges. Doing so will also reduce bills for Californians who have not been able to avail themselves of other distributed energy resource ("DER") programs they have supported, such as net energy metering, for decades.

The Net Value Billing Tariff addresses acute reliability and equity needs effectively and efficiently. By compensating subscribers to Net Value Billing Tariff resources at only the avoided cost value of exported energy derived from the Avoided Cost Calculator ("ACC"), the NVBT encourages deployment of solar plus storage resources which meet the grid needs of today. Moreover, by crediting subscribers at CAISO day ahead prices and allowing for updates to the time of peak hours, the Net Value Billing Tariff meets evolving needs of the grid. By using the Avoided Cost Calculator as the basis for subscriber compensation, the NVBT builds on years of purposeful effort by the Commission to evolve evaluation of DERs to be an integral part of a cost-effective and reliable resource portfolio developed as part of a coherent planning and procurement process. The NVBT would also allow each biennial update to the ACC to be reflected in the export credit rate ("ECR") available to future projects. Thus, as grid needs evolve and those changing needs are reflected in the ACC, the deployment of additional projects will calibrate with the need - either continuing to be deployed because it is economic to do so or pausing until the grid needs to support economic development of new projects.

In addition to meeting the needs of the California grid and ratepayers, the record established in this docket demonstrates that the NVBT is the best means of meeting the goal of Assembly Bill ("AB") 2316 to robustly serve low-income customers through a cost-effective program that benefits all ratepayers. In contrast, the record demonstrates that existing programs do not meet AB 2316's requirement to "robustly serve low-income customers" while also failing to deploy cost-effective resources that are responsive to critical grid needs. The existing Disadvantaged Communities-Green

Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") programs fail to adequately serve low-income customers as the investor-owned utilities ("IOUs") want to maintain these programs at their current size - meaning only 50,000 CARE customers (1.6% of current CARE enrollees) can participate in these two programs.[1] Certain community choice aggregators ("CCAs") seek to expand the DAC-GT program to serve 50% of their CARE/FERA customers residing in DACs,[2] but such an expansion only reaches 69,607 customers[3] and thereby excludes millions of low-income customers residing within their CCA service territories and the IOU service territories where these CCAs do not operate. All the while continuing to be funded by these same ratepayers who have no opportunity to participate in the programs due to limited program capacity and eligibility requirements. These expanded programs would also fail to explicitly allow participation of certain low-income customers, as required by Public Utilities Code Sec. 769.3(a)(3) and (4),[4] by potentially excluding (1) CalFresh/SNAP/LIHEAP program participants who are not CARE/FERA customers, (2) "low-income communities", and (3) communities located on Tribal lands. Thus, even with the CCA's proposed program expansion, its failure to include these low-income customers violates the requirements of Sec. Sec. 769.3(b)(1)(C).[5] In addition to violating statute, maintaining the small size of existing programs, or only selectively expanding them to small subsets of low-income customers runs directly contrary to the Legislature's intent "to support robust low-income customer participation in the community renewable energy program that may be

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[1] This figure assumes enrollment is limited to CARE program enrollees only. See, Exhibit CCSA-004 (Smithwood) at p. 13, ln. 10 to p. 14, ln. 7.
[2] See Exhibit JCCA-01 (Various) at p. 34, lns. 7-8.
[3] See id, Table 1, pg. 34, line 12-13.
[4] All subsequent references are to the Public Utilities Code unless otherwise specified.
[5] Section 769.3(b)(1)(C) requires that modified programs meet all three goals expressed in Sec. 769.3(b)(1)(A). One of these goals, described in Section 769.3(b)(1)(A)(iii) is to promote the robust participation by the range of low-income customers identified in statute in Sections 769.3(a)(3) and (4); see also CCSA Opening Brief, p. 3-4 (discussing statutory interpretation for deficient existing programs).

established for electrical corporations pursuant to Section 769.3 of the Public Utilities Code."[6]

As these comments demonstrate, the Net Value Billing Tariff is cost-effective across a suite of cost-effectiveness scores consistent with Commission guidance on how to use and balance these tests. The NVBT's cost-effectiveness is robust as participating resources will have to carry the risk of changing wholesale energy prices and will need to adapt to changing peak periods over time. The cost-effectiveness scores are also robust given that they incorporate the utilities' worst-case-scenario billing costs which vastly exceed costs experienced in other jurisdictions which have modernized billing processes. Unlike the existing Green Access Programs ("GAPs") and other DER programs, the Net Value Billing Tariff excels on cost-effectiveness scores and limits revenue impact to the difference between the hours in which the ACC allocates avoided costs and the on-peak/off-peak structure of the Net Value Billing Tariff. The NVBT is superior to other DER programs in that it will evolve with the evolution of the ACC. Finally, the Net Value Billing Tariff is well situated to provide additional measurable benefits to non-participants and participants by (1) helping to avoid the state's ongoing extraordinary measures to ensure grid reliability via use of expensive and polluting resources ; (2) paying for capacity building in community-based organizations; (3) leveraging federal funding effectively and in accordance with federal Justice40 goals; and (4) reducing ratepayer costs for complying with Title 24 of the state building code.

The NVBT's excellent cost-effectiveness scores, limited revenue impact, ability to leverage external funds, and yielding of additional benefits to non-participants and participants stands in stark contrast to wholesale programs generally, including power purchase agreements ("PPAs") for projects in the DAC-GT and CSGT programs ("DAC programs"). The existing DAC programs provide a bill

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

discount which is tied to escalating retail rates and divorced from the resource value to non-participating ratepayers. Not surprisingly, as discussed herein, the cost-effectiveness scores of these programs are well below those of the NVBT. As with other comparable wholesale generation programs, DAC program projects are stand-alone solar resources and compensated on a fixed PPA or tariff rate that does not evolve with the grid and places the wholesale energy price risk on ratepayers. This PPA compensation structure means program cost-effectiveness will continue to decline as midday costs fall with increased solar deployment. Particularly when the state needs resources to meet the evening net peak, these programs stand as anachronisms that provide no added resource adequacy. Not only are the DAC programs not cost-effective and not responsive to evolving grid needs, these programs are also not well situated to leverage external funds given their bespoke structure. Unlike well-designed community solar programs, including the NVBT, DAC programs are unlikely to comply with the IRA-related provisions referenced in AB 2316. The existing DAC programs are also non-compliant with federal requirements for how community solar integrates with housing assistance and energy assistance programs.

II. RESPONSE TO QUESTIONS

a. Response to Question 1 – TRC, RIM, and Program Administrator Cost ("PAC") Test Results for the NVBT versus Other Existing Programs Demonstrate that the NVBT is the Best Proposal Offered

Question 1 states: The record in this proceeding is deficient in regards to the cost-effectiveness of existing, modified, and new community renewable energy program proposals. Parties should submit Total Resource Cost, Ratepayer Impact Measure, and Program Administrator Cost test results for their proposals based on the Standard Practice Manual and adhere to previous Commission guidance on the application of cost-effectiveness evaluation and tests.

In Amended Opening Testimony by Witness Fulmer, CCSA provided TRC and RIM test results for the NVBT using Commission approved methodologies yielding high scores for the TRC test[7] and the RIM test.[8] CalAdvocates agreed that the NVBT is cost-effective, but also noted that the costs of billing should be included in a final determination of the NVBT's cost-effectiveness.[9] In Surrebuttal Testimony by Witness Fulmer, CCSA demonstrated that even with the inclusion of the IOU's highest preliminary cost estimates for billing upgrades and program administration, the NVBT was still cost-effective.[10] CCSA has proposed that developers pay for registration, billing costs and program administration costs similar to the framework of approved costs contained in the Virtual Net Metering tariffs of each IOU.[11] Given that these costs are borne by projects, TRC scores incorporate the costs of utility billing and program administration and those costs are excluded from RIM score and PAC analyses.

In reviewing the previously filed cost-effectiveness analysis in light of the ALJ ruling, CCSA noticed that the cost of bill credits to subscribers had been included in the cost of the facility, which impacted the TRC results presented in testimony. The cost of the bill credits applied to participant (subscriber) bills had been used in calculating project costs for the purpose of evaluating the financeability of projects enrolled in the NVBT. However, under the rubric of the Standard Practice Manual, these costs should not have been included as a cost of the facility for the purposes of calculating the TRC score as bill credits are transfer payments. Accordingly, CCSA is presenting updated TRC scores for a 5 MW ground mounted project in Table 1 below that remove these costs. These updated

[7] See Exhibit CCSA-002 (Fulmer) at p. 26 (Table 5 providing TRC results).
[8] See Exhibit CCSA-002 (Fulmer) at p. 28-29 (Table 7 providing RIM results).
[9] See Exhibit CA-03 (Ahlstedt) at p. 1-27, ln. 15 - 1-28, ln. 2.
[10] See Exhibit CCSA-008 (Fulmer) at p. 6, ln. 4 to p. 7, ln. 5 (Table 3 providing revised TRC results).
[11] See, e.g. PG&E Electric Schedule NEMV (detailing costs for services such as disconnection/reconnection, Generator Account metering, one-time charges for Benefiting Account set up, and modification of Benefit Accounts).

TRC scores range from 1.19 to 1.74 – demonstrating the program has exceptionally high overall cost-effectiveness, even after including the worst-case-scenario billing costs presented by the utilities. By requiring facilities participating in the NVBT to be paired with energy storage, the NVBT dramatically increases the value of these facilities to the grid, and subscribers are compensated for their capacity interest in a facility based upon the avoided costs of participating facilities' energy exports.

In response to the ALJ Ruling, CCSA developed a PAC test for a 5 MW ground mounted project to inform the record as it was not included in our testimony. The NVBT garners PAC test scores of 0.81-0.92 the same scores as the RIM test because the utility does not lose any revenue from subscribers. They continue to pay all charges under their otherwise applicable rate for energy they consume from the grid.

CCSA has also modeled TRC, RIM and PAC test results for the DAC-GT program.[12] The results are presented in Table 1 along with the results for the NVBT for ease of comparison.[13]

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[12] The CSGT program has a similar program structure so CCSA anticipates modeling its cost-effectiveness would result in identical scoring. Therefore, CCSA did not undertake an independent analysis of the CSGT program.

[13] Appendix A describes the methodologies used to develop cost-effectiveness scores, bill impacts and other figures discussed in these comments and provides a link to underlying all workpapers supporting the tables and figures unless otherwise provided herein.

Table 1. Comparison of Cost-Effectiveness for NVBT and Existing Programs

			NVBT			DAC-GT		
Utility	**Term**	**ITC %**	**TRC**	**RIM**	**PAC**	**TRC**	**RIM**	**PAC**
PG&E	20	30%	1.19	0.92	0.92	0.79	0.46	0.46
PG&E	25	30%	1.22	0.91	0.91	0.78	0.45	0.45
SCE	20	30%	1.20	0.81	0.81	1.08	0.62	0.62
SCE	25	30%	1.23	0.81	0.81	1.07	0.61	0.61
SDG&E	20	30%	1.40	0.85	0.85	0.85	0.45	0.45
SDG&E	25	30%	1.45	0.85	0.85	0.84	0.44	0.44
PG&E	20	50%	1.43	0.92	0.92	0.91	0.50	0.50
PG&E	25	50%	1.46	0.91	0.91	0.89	0.48	0.48
SCE	20	50%	1.46	0.81	0.81	1.26	0.68	0.68
SCE	25	50%	1.49	0.81	0.81	1.25	0.66	0.66
SDG&E	20	50%	1.70	0.85	0.85	1.00	0.49	0.49
SDG&E	25	50%	1.74	0.85	0.85	0.98	0.47	0.47

Table 1 demonstrates that the DAC-GT program is either not cost-effective or is less cost-effective than the NVBT. The DAC-GT program garnered TRC scores with a range of 0.78 to 1.26 versus the NVBT much higher range of 1.19 to 1.74. In addition, RIM scores for the DAC-GT program, ranging from 0.44 to 0.68, are also significantly lower than the RIM scores garnered by NVBT which range from 0.81 to 0.92.

The cost-effectiveness scores of the DAC-GT (and by extension, CSGT) in a 50% ITC scenario (i.e., where projects receive a 20% Low-Income Economic Benefit Adder) should be viewed as illustrative rather than truly possible outcomes as it is highly unlikely that the DAC-GT and CSGT programs would be able to capture the 20% Low-Income Economic Benefit adder. In addition to the fierce competition for the limited adder referenced in CCSA's testimony, the structure of the DAC solicitations and the ITC adder allocation process will not mesh. The Low-Income Economic Benefit Adder ("LIEBA") are only awarded to projects after they have received an interconnection agreement and permits. However, because of the infrequent timing of IOU or CCA solicitations, and to avoid incurring major costs before securing a PPA, projects bid into the solicitation before having permits and, in some cases, before having an interconnection agreement. Under this framework, bidders would need to make a highly speculative assumption about being awarded a LIEBA which they could not, at the time of bidding, reasonably assume will be secured. The likely result of the disconnects between IOU solicitation timing and requirements and the granting of LIEBA is very speculative bidding with awarded projects failing to garner a LIEBA. Under this outcome, the project economics fundamentally change from those assumed in the project bid. The result of this radical change in project economics is that project fails to achieve commercial operation or seeks to renegotiate the terms of their awarded PPAs. Either outcome undermines program success. This situation contrasts starkly with the NVBT because the NVBT is a walk-up tariff available to all projects that meet its eligibility requirements. Under the NVBT walk-up framework, a project could pursue the LIEBA and, if awarded one by the US Treasury, comply with the rules, procedures, and reporting put forward in the tariff to share that additional value with subscribers as required based on the NVBT proposal presented in CCSA's testimony.

Even if DAC projects secured the adder, it can't be used in a way that is compliant with the underlying legislative requirement that Low-Income Economic Benefit Adder benefits flow to subscribers, not to be priced into project PPAs.[14] Federal incentives would not flow through to DAC program subscribers because the program rules provide a fixed percentage of subscriber savings. Projects enter the programs by bidding a competitive PPA price meaning projects hoping to claim the

[14] PU Code s.769.3(C)(6): "Prioritize the maximum use of state and federal incentives and accelerate implementation of the program to ensure that time- or quantity-limited federal incentives can be obtained **for the benefit of subscribers."** (emphasis added).

Low-Income Economic Benefit Adder would bid lower PPA rates to secure a spot. They have no incentive or requirement to provide higher levels of subscriber savings. Notably, no party supporting the continuation or expansion of the DAC-GT or CSGT program has offered up a program structure that will allow for low-income subscribers to receive the additional value stemming from the Low-Income Economic Benefit Adder.

b. Response to Question 2 – The NVBT is Beneficial to All Ratepayers Resulting in Lower Potential Cost Shifts, Lower Monthly Bill Impacts for Non-Participating Ratepayers, Reasonable Bill Savings for Participating Customers, and Measurable and Quantifiable Benefits to both Participating and Non-Participating Ratepayers

Question 2(a) states: How should any cost shift of or cost impact on non- participating ratepayers of existing, modified, or new community renewable energy proposals be quantified?

Decision no. ("D.") 22-12-056, provides guidance on how to assess the cost shift of – or cost impact on – non-participating ratepayers from customer-focused distributed generation programs. In D.22-12-056, the Commission assessed impacts on non-participating customers under two frameworks: (1) a cost-effectiveness analysis consistent with the Standard Practice Manual[15] and D.19-05-019, and (2) a cost of service analysis that compares the cost to serve program participants against their total bill payments.[16] Both of these frameworks should be used to quantify and assess the cost impact of existing, modified or new proposals offered in this docket. This approach is reasonable because, as discussed below in response to Question 2(c), facilities participating under the NVBT are distributed energy resources and the subscription program the NVBT enables is a customer-focused distributed generation ("DG") program designed to expand access to distributed energy resources to those who cannot install a

[15] The Standard Practice Manual does not use the term" Cost shift" or "Cost Impact", but instead measures the lifecycle impact on ratepayers using the Ratepayer Impact Measure Lifecycle Revenue Impact test ("LRRIM") which we refer to in tables as the "cost impact: "or "revenue impact" in these comments.
[16] See D.22-12-056, p. 14 (discussing framework of Lookback Study for assessing NEM tariffs).

DG system onsite.

The Commission uses four tests to assess the cost-effectiveness of customer-focused distributed generation programs: the Participant Cost Test ("PCT"), the PAC test, the TRC test, and the RIM test.[17] The ALJ Ruling asks parties to provide analysis using the PAC, TRC, and RIM tests and CCSA provided the requested analysis in response to Question 1 above.

A cost of service analysis was not undertaken by CCSA because the analysis would show that participation in the NVBT has no impact on subscriber's contribution to their cost of service. Subscribers to NVBT facilities will continue to pay for all energy they consume from the grid at their otherwise applicable rate the same as they did prior to subscribing to a facility. This outcome is different from customers who install on-site generation as their self-consumption avoids contribution to most fixed costs of service that are embedded in volumetric rates.[18] Thus, community solar subscribers will continue to contribute to cost of service recovery at the same level as they did prior to subscribing to an NVBT facility. This outcome is again different than participants in net energy metering ("NEM") who have higher bill payments compared to their cost of service prior to enrolling in NEM but after enrolling in NEM contribute less than their cost of service for residential NEM customers.[19] Because of these features of the NVBT, which eliminates cost of service impacts, CCSA did not perform a cost of service study.

Question 2(b) states: What would be the resulting cost shift for new community renewable energy program proposals? How would this compare to any cost shifts associated with existing or modified programs? How do the costs of new community renewable energy program proposals compare to the costs of wholesale clean energy resources? Provide all assumptions (size of program, compensation rate, outside funding or incentives, administrative costs, etc.).

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[17] See id. at p. 14-15.
[18] See id. at p. 17.
[19] See D.22-12–56, Table 2, p. 16 (Ratio of Bill Payment to Cost of Service, NEM 1.0 vs. NEM 2.0).

The programs under review in this docket are programs designed to increase access to distributed energy resources to customers who cannot install onsite DG. AB 2316 requires the Commission to determine whether it is beneficial to ratepayers to establish a community renewable energy program that provides "bill credits to subscribers based on the avoided costs of the program's facilities, as determined by the Commission's methods for calculating the full set of benefits of distributed energy resources." The NVBT is tailored to achieve these AB 2316 requirements. Even if one were to disregard the standard set out in AB 2316, the NVBT stands on its own merits by compensating resources in a manner that is superior to the alternatives for distribution-interconnected generators.

There are limited wholesale programs against which to compare the NVBT. As SEIA pointed out, "since 2017 only eight ReMAT projects totaling 12.4 MW have been contracted. Four small hydro projects totaling 5.3 MW are online; two solar projects of 2 MW each and a wind project of 3 MW remain under development, and a small hydro project of 0.1 MW has terminated its contract. Moreover, in the last 5 years only one new QF standard offer contract has been signed, for a 20 MW project and that project remains under development."[20] While the DAC programs have a subsidized bill credit, participating projects are procured through solicitations by the IOU and CCA administrators and, therefore, the PPAs executed are the other comparable wholesale resource to compare to the NVBT. Review of existing wholesale programs shows they result in more expensive resources for customers when compared on an equal basis to the NVBT and place the risk of changing energy prices on ratepayers instead of projects. First, the DAC-GT and CSGT programs operate on a wholesale model for procurement of distributed generation resources to serve participants and rely on solicitations and PPAs to compensate participating resources. The RIM/TRC/PAC test scores for the DAC-GT program

[20] SEIA Opening Brief, filed May 17, 2023, p. 45.

demonstrate that the wholesale procurement and PPA approach is not cost-effective under certain scenarios and has significantly lower RIM and PAC test scores than the NVBT. So, on a megawatt ("MW") per MW basis of program resources, as discussed below, the DAC-GT program results in larger cost impacts to non-participants customers on a per-MW basis than the NVBT. This result is not surprising as the program relies on solar resources that are not responsive to current or future grid needs as the resource is not paired with energy storage and they provide a bill credit that is tethered to retail rates.

DAC programs rely on a subsidized bill discount tied to retail rates to achieve bill savings rather than relying on the value of energy exported by the facility to support customer savings as well as support financing of the project. Reliance on a retail rate compensation framework for subscribers is contrary to the legislative intent expressed in AB 2316 to compensate subscribers for the avoided costs produced by the DG resource they are subscribed to. It is also contrary to the general thrust of D.22-12-056 which sought to reform customer DG programs such as NEM and virtual net metering ("VNEM") to move away from retail rate-based compensation and to an avoided cost value-based framework. The Commission sought to "improve price signals by better aligning them with the electric grid's conditions, both day and night…incentivize the adoption of combined solar and storage systems…[to] help meet California's climate goals and increase reliability, while promoting affordability across all income levels."[21] The NVBT directly incentivizes these outcomes because the ECR relies on avoided costs identified in the ACC to create a framework that incentivizes exports during the evening peak during the months of the year when capacity is needed most. This overall ECR framework is conceptually the same as the credit rate adopted in D.22-12-056 and has the added benefit of allowing the peak to shift as

[21] D.22-12-056, p. 2.

grid needs evolve. D.22-12-056 embraced the merits of this approach to compensation for exports, finding that "the addition of storage provides greater benefits…to the grid."[22] This is a point the IOUs agreed with noting that "excess energy can be stored…to meet load at its peak later in the day…[and that] "pair[ing] storage will reduce our dependence on carbon emitting resources."[23]

Setting aside the bill discount subsidies provided in the DAC programs, the NVBT is superior to the cost of purchasing power from the DAC programs as well as from the other comparable wholesale program, the Renewable Market Adjusting Tariff ("ReMAT). The NVBT is less costly to ratepayers and places more risk on project owners (rather than ratepayers). Witness Fulmer's workpapers[24] show the revenues a ground-mounted community solar facility receives under the NVBT for both generation directly exported by the solar system and solar energy exported after being stored in the battery. Table 2 replicates the average annual cents/kWh compensation that a sample NVBT project in PG&E receives for the system's solar generation that is directly exported onto the grid.[25] By looking at the compensation for solar exports, an apples-to-apples comparison can be made with the solar-only resources in the DAC programs and ReMAT.

[22] See D.22-12-056, p. 98.

[23] See id.

[24] See CCSA-Fulmer_MRW CA VDER Output Summaries Workpaper Amended Ground Mount.xls in workpapers for the Amended Prepared Direct Testimony of Mark Fulmer (Exhibit CCSA-002) available at: https://docs.google.com/spreadsheets/d/1obTpI7xnj5UWne95UhM0d-yhUWdJumxQ/edit?usp=sharing&ouid=11427?8512876489910609&rtpof=true&sd=true.

[25] Ibid, Tab "PG&E 25 Det." Columns A and B, rows 119-125.

Table 2. PG&E Average Annual Solar Export Compensation Rates for A Ground Mounted NVBT Project (2025)

Capacity value	$ 0.0163
Environmental value	$ 0.0060
T&D value	$ 0.0124
Sum of above locked-in ACC values	$0.0347
Projected energy value (not locked – a flow through of CAISO day ahead rates)	$0.0450
Average projected ECR compensation, per kWh solar generation immediately exported (Total)	$ 0.0797

As Table 2 shows, only 3.47¢/kWh of annual solar-only NVBT compensation is set by tariff;[26] the remaining 4¢/kWh projected compensation is a California Independent System Operator ("CAISO") day ahead market-based rate which the project owner takes at risk when financing the project as lower CAISO prices will mean lower revenues to the project and, thereby, lower bill credits. By contrast, DAC program PPAs and ReMAT PPAs[27] place all the risk of wholesale energy prices on ratepayers with fixed, non-variant compensation that is dictated in the relevant ReMAT tariff and the DAC program PPAs executed using the standard DAC program PPA adopted by the Commission. As shown in Table 3, ReMAT and DAC-GT/CSGT projects have set compensation for solar-exports that are between 46% and 138% higher than the set compensation for NVBT projects.

The comparison is starker when considering that the NVBT can offset resource adequacy needs by being a load modifier while DAC program and ReMAT projects are unable to provide resource

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[26] This is a weighted average of on peak and off-peak production and rates; most of this compensation would be in summer afternoons.

[27] See DAC Program: Form of Power Purchase Agreement, Power purchase Agreement Between Pacific Gas And Electric Company and [Seller] available at: https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/Disadvantaged%20Communities/Appendix_B-PGE_2020_DAC_PPA_FINAL.docx.

adequacy. Wholesale generators only realize resource adequacy value if they are deliverable. ReMAT and DAC program projects are not required to be deliverable and therefore do not provide resource adequacy value, even if they were paired with storage. In effect, the DAC program PPAs and ReMAT tariff are contracts for an energy-only resource. Therefore, to make a truly apples-to-apples comparison the value of capacity needs to be removed from the NVBT as that is a service provided that is additional to the energy-only product provided by DAC program and ReMAT facilities under their PPAs. The third column in Table 3 makes the comparison between the energy-only compensation for solar exports from NVBT projects and REMAT and DAC program PPAs. Table 3 shows that the ReMAT and DAC program PPAs are paying 176% to 348% more for solar energy than the NVBT.

Table 3. Locked-In Solar-Only Compensation Rate for NVBT, DAC-GT/DAC-CSGT, and ReMAT

	Locked in export compensation rate for exported solar generation ($/kWh)	**Premium to NVBT**	**Fixed rate for solar exports, net of generation capacity value ($/kWh)**	**Premium to NVBT**
NVBT	0.0347		0.0184	
RE-MAT	0.05072[28]	46%	0.05072	176%
DAC-GT/ DAC-CSGT PPA	0.0825[29]	138%	0.0825	348%

Fourth, the NVBT is also superior to wholesale power purchases made in ReMAT and DAC program PPAs as CCSA has proposed allowing the peak periods underlying the ECR to adjust over the

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[28] PG&E RE-MAT tariff, "As-Available Peaking" price, sheet 8, available at: https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/ReMAT/ELEC_SCHEDS_E-ReMAT.pdf.

[29] DAC PPA price. See Appendix A for how DAC PPA rates were derived.

term of the ACC lock in, as frequently as every biennial update of the ACC, allowing compensation value to remain aligned with the hours that are driving the capacity needs and pollution to be avoided. In practice this means that if, over time, peak periods shift further into the evening, solar generation from NVBT projects will be compensated at lower (and potentially negative) rates if they do not adjust to follow the peak while the ReMAT and DAC program projects will continue to receive their contracted revenue. The practical effect is that the NVBT will adapt to remain cost-effective, but the DAC program and ReMAT PPAs will only become less cost-effective as additional solar generation is deployed.

Finally, the NVBT has unique benefits compared to wholesale programs including, the DAC-GT/CSGT/Green Tariff Shared Renewables ("GTSR") programs in that significant risks are shifted from ratepayers to facility owners for program success. Unlike the DAC-GT/CSGT/GTSR programs, developers must keep facilities consistently subscribed to be compensated by subscribers – so developers, not ratepayers, bear program success risk. Further, under CCSA's proposed ECR, developers bear energy market risk as the value of energy within the ECR would be a pass through from the CAISO.[30] Under DAC-GT/CSGT/GTSR programs, ratepayers bear both the energy market risk (if the market value deviates from the rate set in the underlying resources' power purchase agreement) and program success risk. Program success risk from the DAC-GT/CSGT/GTSR programs is material as SDG&E has spent nearly all its testimony discussing the failure of their existing programs due to customer load migration and there has already been disagreement with CCAs over treatment of legacy facilities and cost recovery.[31]

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[30] See Exhibit CCSA-007 (Smithwood), p. 16, lns. 17-20.
[31] See Exhibit SoCal CCA-03 (Dickman), Sections III, IV, and V.

Discussion of impacts from the NVBT and other DAC programs is discussed in response to Question 2(c) as the magnitude of any cost impact is directly related to bill impacts.

Question 2(c) states: For new community renewable energy proposals, what would be the potential monthly bill impacts for non-participating ratepayers should the proposals be adopted? For new community renewable energy proposals, what would be the potential monthly bill impacts for participating ratepayers should the proposals be adopted?

The NVBT is designed specifically to avoid cost impacts for non-participant ratepayers by having the energy portion of the ECR based on actual CAISO prices and the remainder of values comprising the ECR being the avoided cost values in the ACC. However, it is important to note that tests for cost impacts suffer from over precision. The Commission explained that the hour-by-hour allocation of the ACC's values shouldn't be applied directly to compensation given the false precision of the hourly allocation of ACC values based on "potentially inaccurate forecasts of a specific hour's weather and other conditions."[32] Given the scatter of hours over which avoided costs are allocated in the ACC, which are highly likely not to reflect actual real world conditions, the NVBT allocates those costs to a coherent set of hours based on the peak loading that drives those costs. As a result, the alignment of the ECR with the ACC is not exactly the same resulting in a RIM score less than 1. However, given this score is based on an allocation of the same ACC values to a coherent set of on and off peaks, any resulting "cost shift" should be viewed skeptically as it is a product of the ECR not being based exactly on an 8760-hour allocation of avoided costs in the ACC. Notwithstanding the fact that the measure of cost impacts reflect the gap between the exact 8760 hours and the on and off peak ECR structure of the NVBT, and not compensation above the ACC value, CCSA has calculated cost impacts of the NVBT consistent with the revenue impact methodology outlined in the Standard Practice Manual, but the

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[32] D.22-12-056, p. 142.

NVBT does not create a cost shift as it relies solely on the ACC and CAISO zonal day ahead hourly market prices to determine the value of exported energy.

Table 4 below shows the lifecycle revenue impact on a net present value basis ("NPV") per MW for both the NVBT and the DAC-GT program. As demonstrated in Table 4, the DAC-GT program results in a significantly higher cost shift per MW than a comparable MW of an NVBT participating resource - in some instances nearly 500% higher cost impacts per MW than NVBT resources. Over the lifecycle of the DAC-GT program, revenue impacts on a per MW basis range from $1.0 to $2.6 million while the lifecycle revenue impacts of NVBT resources ranges from $0.4 to $1.2 million per MW.

Table 4. Lifecycle Impacts of NVBT and DAC-GT Programs

			NVBT			DAC-GT		
Utility	**Term**	**ITC %**	**Lifecycle NPV Revenue Impact ($million/MW)**	**Lifecycle Revenue Impact per kWh***	**Lifecycle Non-Participant Residential Monthly Bill Impact****	**Lifecycle NPV Revenue Impact ($million/MW)**	**Lifecycle Revenue Impact per kWh***	**Lifecycle Non-Participant Residential Monthly Bill Impact****
PG&E	20	30%	$0.4	$0.00021	$0.11	$2.3	$0.00111	$0.56
PG&E	25	30%	$0.5	$0.00021	$0.11	$2.6	$0.00112	$0.56
SCE	20	30%	$1.0	$0.00050	$0.25	$1.5	$0.00071	$0.36
SCE	25	30%	$1.2	$0.00052	$0.26	$1.8	$0.00074	$0.37
SDG&E	20	30%	$1.0	$0.00042	$0.21	$2.4	$0.00124	$0.62
SDG&E	25	30%	$1.1	$0.00042	$0.21	$2.8	$0.00125	$0.62
PG&E	20	50%	$0.4	$0.00021	$0.11	$1.9	$0.00095	$0.47
PG&E	25	50%	$0.5	$0.00021	$0.11	$2.3	$0.00097	$0.48
SCE	20	50%	$1.0	$0.00050	$0.25	$1.2	$0.00055	$0.28
SCE	25	50%	$1.2	$0.00052	$0.26	$1.4	$0.00059	$0.29
SDG&E	20	50%	$1.0	$0.00042	$0.21	$2.0	$0.00105	$0.53
SDG&E	25	50%	$1.1	$0.00042	$0.21	$2.4	$0.00108	$0.54

*Assumes 1 GW program size across all three utility service territories. **Assumes 500 kWh of monthly usage.

The higher revenue impact for the DAC-GT program when compared to the NVBT program directly impacts residential monthly bills. As shown in Table 4, the residential nonparticipant monthly bill impact of the DAC-GT program assuming a program size of 1 GW shows a nonparticipant residential bill impact ranging from $0.28 to $0.62 per month versus the NVBT's residential nonparticipant monthly bill impact of $0.11 to $0.26 for 1 GW of program capacity.

As noted earlier, any cost impact analysis must be taken with a grain of salt as the Commission has recognized the false precision of over reliance on the granularity of the ACC. Accordingly, to the extent deviations from the pure results of the ACC to create an ECR creates a cost shift under standard analysis, then every credit rate will result in a cost impact on some level, and reasonable experts can debate what the amount of that cost impact is. Moving back from a narrow focus on cost impact resulting from deviations from the ACC, the NVBT directionally gives the electric system exactly what it needs - grid harmonized resources whose subscribers are compensated under an avoided cost framework. The overall cost-effectiveness and cost impact analysis presented in these opening comments demonstrates the wisdom of the Legislature to "[m]inimize impacts to non-participating customers by prohibiting the program's costs from being paid by non-participating customers in excess of the avoided costs."[33]

For subscribers participating in the NVBT, the primary benefit they receive is the bill credit from their subscription. In response to recommendations from the California Environmental Justice Alliance, the Vote Solar, and the Natural Resources Defense Council ("CEJA-VS-NRDC") and The Utility Reform Network ("TURN") that low-income subscribers should receive minimum bill credits, CCSA established a commitment to a *minimum* 20% of bill credit savings for low-income subscribers

[33] Sec. 769.3(c)(3).

participating in projects that receive the 30% ITC and a *minimum* bill credit savings of 25% for low-income subscribers that participate in projects receiving the Low-Income Economic Benefit Adder (total ITC of 50%).[34]

Table 5 provides a comparison of the monthly minimum bill savings that can be expected for low-income subscribers receiving bill credits from NVBT subscriptions and the monthly savings for customers participating in the DAC GT/CSGT program. For CARE customers the NVBT can achieve monthly savings comparable to the DAC programs without the substantial non-participant impact that comes from the DAC programs. FERA customers realize higher savings, but FERA customers account for only 77,034 customers out of the 10.6 million residential customers within PG&E, SCE, and SDG&E service territories.[35] It is also important to note that the NVBT bill savings are based on the *minimum percentage* of the bill credit *required* to be provided to low-income participants. Subscriber Organizations may choose, or be required, to provide a greater percentage of the bill credit should they, for example, receive funding under the US EPA's Solar for All competition.

[34] See Exhibit CCSA-007 (Smithwood), p. 52, ln. 9 to p. 55, ln. 14 (discussing rebuttal testimony of CEJA-VS-NRDC and TURN and CCSA's commitment for minimum bill credit savings).
[35] See R.22-07-005, "E3 Fixed Charge Tool," (Updated April 2023), "Customer Counts" tab https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-flexibility-oir/fixed-charge-design-model-2023-04-13.xlsb

Table 5. Monthly Bill Savings for Low-Income NVBT Participants vs DAC Program Participants

			NVBT	DAC-GT	
Utility	**Term**	**ITC %**	**First Year Participant Monthly Bill Savings**	**First Year CARE Participant Monthly Bill Savings**	**First Year FERA Participant Monthly Bill Savings**
PG&E	20	30%	$20.80	$25.25	$32.33
PG&E	25	30%	$20.77	$25.25	$32.33
SCE	20	30%	$22.73	$24.43	$29.61
SCE	25	30%	$23.01	$24.43	$29.61
SDG&E	20	30%	$28.11	$31.58	$41.08
SDG&E	25	30%	$28.42	$31.58	$41.08
PG&E	20	50%	$26.00	$25.25	$32.33
PG&E	25	50%	$25.96	$25.25	$32.33
SCE	20	50%	$28.41	$24.43	$29.61
SCE	25	50%	$28.76	$24.43	$29.61
SDG&E	20	50%	$35.14	$31.58	$41.08
SDG&E	25	50%	$35.52	$31.58	$41.08

In addition to having higher lifecycle cost impacts, as PG&E has noted, the CCAs' request to expand the DAC-GT and CSGT programs for their customers alone results in cost recovery concerns between unbundled and bundled customers.[36] Cost recovery concerns are avoided by the NVBT because both unbundled and bundled customers can subscribe to facilities participating in the NVBT on an equal basis, even if their CCA declines to offer their own program, and costs are only borne by the load serving entity which realizes the avoided cost benefits of the tariff.[37]

[36] See Exhibit PGE-03, p. 9, lns. 15-28 (opposing the Joint CCAs' request to expand their programs).
[37] See Exhibit CCSA-007 (Smithwood), p. 38, ln. 5 to p. 39, ln. 7.

Question 2(d) states: Beyond bill impacts, what would the quantifiable and measurable benefits be to non-participating ratepayers of a new community renewable energy program? Similarly, beyond bill impacts, what would the quantifiable and measurable benefits be to participating ratepayers of a new community renewable energy program?

As a preliminary matter, participants and non-participants alike benefit from the avoided costs realized by the NVBT and the federal and state funding that can be captured by establishment of the NVBT in 2023. As discussed in response to Question 3 below, solar plus storage facilities participating in the NVBT are distributed energy resources whether they are ultimately considered to be - "in front of the meter" ("IFOM") or behind the meter ("BTM") by the Commission. The Commission has found that the measurable and quantifiable benefits of distributed energy resources are the seven categories of avoided costs calculated by the Avoided Cost Calculator: "generation capacity, energy, transmission and distribution capacity, ancillary services, Renewables Portfolio Standard, greenhouse gas emissions, and high global warming gasses."[38] D.22-12-056 clarified that "the avoided costs determined in the Avoided Cost Calculator are the utilities' marginal costs of providing electric service to customers. Those costs can be avoided when the demand for energy decreases because of distributed energy resources, and are, thus, the benefits of using distributed energy resources."[39] All seven of these quantifiable benefits accrue to participating and non-participating customers as they are reductions in demand that avoid utility costs. In addition to these avoided costs, Witness Smithwood spoke at length in testimony about the benefits of capturing available state and federal funds for the benefit of participating and non-participating ratepayers.[40] Beyond the avoided costs and the benefits from potential funding

[38] See D.22-12-056, p. 59.
[39] See id.
[40] See Exhibit CCSA-001 (Smithwood) at pp. 110-112 (discussing the financial, reliability, public health, and resilience benefits of authorizing the NVBT).

opportunities realized by all ratepayers, there are several other quantifiable and measurable benefits to participants and non-participants alike that would come from adoption of the NVBT. These readily measurable benefits alone add up to billions of dollars and include:

(1) the avoidance of ratepayer-and taxpayer-funded extensions of fossil fuel resources and other extraordinary measures to provide for electric service reliability;

(2) funding low-income community engagement and capacity building for community-based organizations;

(3) leveraging federal funds *beyond* tax credits and Inflation Reduction Act funding discussed in testimony to include reduce participant bills while increasing clean energy production;

(4) ensuring low-income renters receiving US Department of Housing and Urban Development ("US HUD") assistance are not harmed; and

(5) savings to ratepayers from Title 24 compliance.

Avoidance of Ratepayer- and Taxpayer-Funded Emergency Measures

California has faced an acute reliability challenge in recent years. In response to this ongoing reliability challenge, California has funded, through both ratepayer and taxpayer funds, emergency generation resources to prevent blackouts. For example, the Electricity Supply Strategic Reliability Reserve Program ("ESSRRP") is a taxpayer funded effort to support fossil-fueled resources administered by the Department of Water Resources. Under the ESSRRP, the Department of Water Resources is planning to utilize $1.2 billion to extend the operation of three coastal natural gas plants for three years.[41] These extensions are only the most recent extensions of projects which were slated to

[41] "DWR Investment Plan" filed June 3rd in California Energy Commission docket 22-RENEW-01 and available

retire years ago and this $1.2 billion will only support these projects for three years with the hope that even further extensions will not be needed.

The NVBT can address this challenge in a better way. Ground-mount NVBT projects do not require subsidies, will operate for over two decades, and can provide system reliability everywhere and local reliability in local reliability areas where ground mount projects can be sited. Rooftop projects would need incentives to be deployed but could be deployed in land-constrained Local Reliability Areas, such as the LA Basin, where deployment of ground mounted projects is improbable. If $1 billion were invested to support the deployment of rooftop community solar plus storage[42] in land-constrained Local Reliability Areas where these once-through-cooling ("OTC") plants are located, these projects would provide the equivalent amount of capacity as $2.78 billion spent on gas plant expenditures, without the accompanying greenhouse emissions of methane and carbon dioxide.

Figure 1 compares the cost to taxpayers of the three gas plant extensions if those costs, to keep operational fully depreciated plants, were normalized to be comparable to the funds needed from non-ratepayer (i.e., AB 205 programs, EPA Solar For All, etc.) funds to deploy rooftop community solar projects or ground mount projects. As Figure 1 shows, $1 billion would support 1 gigawatt of OTC plants for *7 years*; that same amount would support 1 gigawatt of rooftop community solar plus storage on the Net Value Billing Tariff *for 20 years*. Given that, as Witness Kennerly's testimony demonstrated, ground mount projects are viable on the NVBT tariff alone, no payments would be

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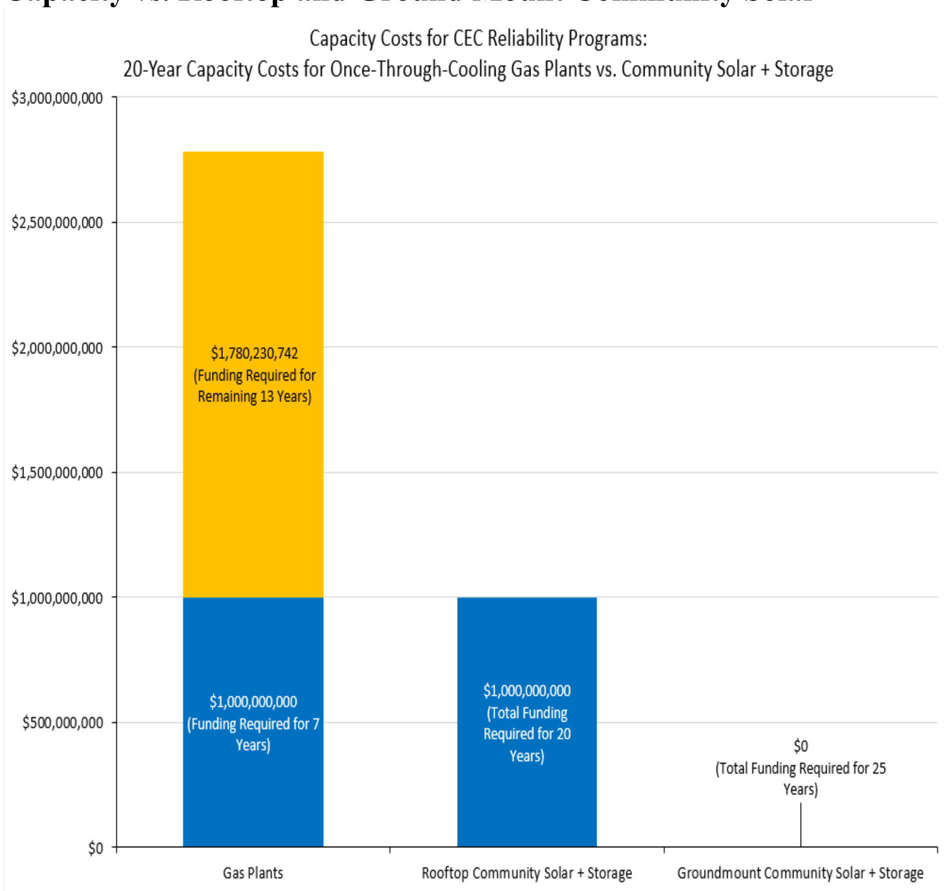
here: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250477&DocumentContentId=85254.

[42] The Energy Commission is in the process of administering $600 million through the Distributed Electricity Back Up Assets program and has authorization for $1 billion through the Clean Energy Reliability Investment Plan. Community solar is a rare carbon free asset that can meet the aims of these two programs in the five-year timeframe they are looking to deploy resources. See CEC Docket 22-RENEW-01 and Docket 21-ESR-01; see, also, Exhibit CCSA-001 (Smithwood), p. 93, ln. 15 to p. 94, ln. 16.

needed for those facilities which can provide system reliability statewide and local reliability in LRAs where ground mount projects are probable.

Given the recent history of having to extend gas plant operations and the NVBT's ability to yield over a gigawatt of capacity over the next 3 years, the NVBT holds the promise of saving ratepayers substantial costs *outside* of those quantified in the ACC.

Figure 1: Comparison of CEC/DWR 20 Year Capacity Cost Support OTC Gas Plant Capacity vs. Rooftop and Ground Mount Community Solar



Calculating the recent expenditure to extend the operation of the OTC gas plants as a $/kW-yr capacity cost further demonstrates how expensive capacity is for the emergency actions needed. A weighted average of the three plants would result in $139/kW-yr above and beyond the capacity cost reflected in the ACC.

Table 6. Capacity Cost of Taxpayer-Funded Extension of OTC Plans

$/kW-yr Comparison of DWR Funding for Once Through Cooling Plants vs. Community Solar + Storage	
Plant Name	**$/kW-yr**
AES Alamitos	$154.40
ARS Huntington Beach	$155.50
GenON	$124.73
Gas Plant Average	**$139.01**
Rooftop Community Solar + Storage	$50.00
Ground mount Community Solar + Storage	$0.00

While the cost of the extension of the OTC gas plants was paid with tax revenues, it is nonetheless a cost borne by Californians. If the three plants had been paid out of utility rates for the three largest IOUs, rather than taxpayer funds, the cost would have amounted to an additional $3.10 per month for a residential customer consuming 500kWh/month residential customer, as outlined in Table 7.

Table 7. Bill Impact of Gas Plant Extensions if they had been paid via Ratepayer Funds instead of Taxpayer Funds

Facility	Cost to Ratepayers: Bundled + Delivery (SCE, PG&E, and SDG&E ratepayers)- $/kWh	$/month cost for 500kwh/month customer
AES Alamitos	$0.0027	$1.35
AES Huntington Beach	$0.0005	$0.25
GenON	$0.0029	$1.45
Total	**$0.0062**	**$3.10**

<u>Avoided Back Up Generator Impacts</u>

In response to summertime energy shortages in 2020 and 2021 caused by extreme heat, lack of hydropower due to drought, and wildfires, Governor Newsom issued emergency orders suspending air quality regulations and generation restrictions on backup generators ("BUGs"), the majority of which are powered by diesel fuel.[43] While justified by the need to prevent wide scale power outages, these measures come at a cost – both to ratepayers' wallets as well as to public health. In addition to being a significant source of CO_2 emissions, diesel powered BUGs emit particulate matter, volatile organic compounds (VOCs), nitrous oxide (NOx), and sulfur dioxide (SO_2), all compounds that state and federal regulators classify as harmful to human health.

Governor Newsom's 2021 emergency declaration suspended air quality regulations from the California Air Resources Board ("CARB") and local air quality management districts that otherwise prevent the operation of diesel-powered BUGs. The order also doubled customer payments from the

[43] "Proclamation of a State of Emergency", Executive Department, State of California, (July 30, 2021) https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

Emergency Load Reduction Program ("ELRP") from $1 per kilowatt to $2 per kilowatt – payments funded by California taxpayers. The order also allowed participating customers to shift to using high emitting BUGs to offset their incremental capacity reductions through the expanded ELRP. As Table 8 shows, in addition to the costs already incurred for ELRP in 2021 and 2022 this program could cost ratepayers another $600 million, assuming the program is not further extended or expanded.

Table 8. ELRP Cost Cap Authorizations and Potential Program Costs

	Annual ELRP cost cap[44]	Aggregate Potential 2023-2024 ELRP costs
PG&E	$ 94 Million	$282 Million
SCE	$76.6 Million	$229.8 Million
SDG&E	$31.1 Million	$93.3 Million
TOTAL	$201.7 Million	$605.1 Million

The growth of BUGs has not been trivial. An October 2021 study from economic consultancy M. Cubed found an increasing prevalence of BUGs – nearly 90% of which are diesel fueled – across the state of California, indicating the hidden costs of California's backup generation fleet are rising.[45] After submitting public records requests to the Bay Area and South Coast Air Quality Management Districts (BAAQMD and SCAQMD), M. Cubed found that Bay Area BUG capacity increased from 3,810 MW in December 2018 to 4,840 MW in 2021. The increase was even more stark in the southern part of the state, with backup generator capacity rising from 2,697 MW in 2020 to 7,630 MW in 2021. These generators are disproportionately located in disadvantaged communities scoring in the top 80th percentile

[44] As adopted in D.21-12-015, pp. 166-167.
[45] "Diesel Back-Up Generator Population Grows Rapidly in the Bay Area and Southern California", M. Cubed (October 2021), https://www.bloomenergy.com/wp-content/uploads/diesel-back-up-generator-population-grows-rapidly.pdf.

based on the CalEnviroScreen Fourth Assessment; 47% of the generators in SCAQMD were in top 80% DACs, while 17% of generators in BAAQMD territory were in top 80th percentile communities. Thus, in summers when the resource supply in California is too low to meet demand during extreme events – which are expected to become more prevalent as the impacts of climate change intensify – the state turns to its fleet of dirty but reliable BUGs, and Californians living in disadvantaged communities disproportionately bear the health impacts from the use of these resources. M.Cubed's analysis concluded that the energy generated by BUGs in BAAQMD and SCAQMD could cause negative health impacts costing upwards of $136 million per year. The NVBT is tailored to avoid the hidden cost of BUGs by providing a viable path to the development of firm, zero carbon community solar plus storage resources that are incented to provide energy during the evening ramp during hot summer months – the same hours when BUGs are typically brought online as a power provider of last resort. Furthermore, the power outages in August 2020 saw a load shed of 932 MW, impacting nearly 500,000 Californians.[46] While the harm caused by this load shed is not readily calculable, the NVBT tariff can plug this gap by facilitating over 1 GW of much needed community solar plus storage capacity coming online as soon as in three years and strongly incentivizing those resources to export energy during hours when CAISO demand peaks.

Funding Capacity Building for Community-Based Organizations

One of the costs of community solar plus storage, accounted for in the TRC score, is the cost of customer acquisition. However, this "cost" actually produces a benefit beyond avoided costs and bill savings to participants and non-participants alike. Specifically, community solar providers often work

[46] "Root Cause Analysis: Mid-August 2020 Extreme Heat Wave"; CAISO, CPUC, & CEC (January 13, 2021); https://www.bloomenergy.com/wp-content/uploads/diesel-back-up-generator-population-grows-rapidly.pdf.

with community-based organizations to subscribe projects. In response to testimony from CEJA-VS-NRDC and TURN highlighting their desire for community-based organizations to have a role in subscribing projects, CCSA proposed *requiring* subscriber organizations to have such relationships with community organizations.[47] Witness Kennerly's CREST workpapers[48] quantify this payment to community-based organizations to acquire customers at $100/kW, meaning that 4,000 MW of community solar plus storage (the program cap proposed by Cal Advocates) would yield up to $400 million in investment in community groups subscribing customers.

Leveraging Additional Federal Funds

Beyond leveraging funding in the Inflation Reduction Act, recent events make clear that the NVBT can likely further enhance benefits for low-income subscribers and deploy new renewable energy resources in ways that the existing programs cannot.

On June 15th, the US Department of Health and Human Services ("US HHS") released guidance for state administrators of Low-Income Home Energy Assistance Program ("LIHEAP") Block Grant funds explicitly allowing LIHEAP funds to be used for community solar subscriptions.[49] This change in policy gives local community benefit organizations a way to further leverage their funding to serve low-income households in need while deploying new clean energy. California receives approximately $200 million per year in LIHEAP funding.[50] If these funds were used to pay for community solar

[47] See Exhibit CCSA-004 (Smithwood), p. 49, lns. 1-11 (supporting documentation in Marking Implementation Plans submitted as part of registration requirements regarding partnerships with community-based organizations).
[48] See workpapers for Amended Opening Testimony Witness Jim Kennerly, specifically SEA CA CCSA CREST_Amended Testimony_FINAL.xls, tab "Input Dashboard", row 22, available in Appendix A.
[49]US Department of Health and Human Services, Administration for Children and Families: Low-Income Home Energy Assistance Program. "Information Memorandum LIHEAP-IM-2023-04" (June 15, 2023) https://www.acf.hhs.gov/sites/default/files/documents/ocs/COMM_LIHEAP_IM%202
[50] Data on annual LIHEAP funding is available at US Health and Human Services' website "LIHEAP Clearinghouse": https://liheapch.acf.hhs.gov/Funding/funding.htm.

subscriptions that funding could yield $240 million per year in savings, allowing those dollars to go further while deploying an additional 546 MWs of community solar plus storage serving low-income customers.

<u>Meeting US HUD Guidance to Ensure Low-Income Renters Are Not Harmed</u>

Existing programs likely fail to conform with federal requirements for community solar and thus will harm low-income renters. US HUD rental assistance requires that rent include a utility allowance as part of the cost of the tenants rent and the assistance they receive. Under US HUD assistance, if utility costs go down, a tenant's rent rises to compensate. US HUD has provided guidance to individual states over the years, including to California for the Solar on Multifamily Affordable Housing ("SOMAH") program, providing exceptions to this policy for community solar programs.

Last summer, HUD provided national guidance.[51] For Public Housing, in this guidance, HUD made clear that bill credits must be based on the generation of a facility and NOT a reduction based on the customer's rate to avoid impacts on utility allowances.[52] Since the DAC programs are a flat 20% reduction in the customer's otherwise applicable rate untethered from production from the underlying solar facility, they are likely to impact utility allowance schedules under HUD's guidance which could result in rent increases for participants under Factor 2.a within the Guidance.[53] In contrast, the NVBT provides bill savings based on the production of the community solar facility that comes from a third-party. The structure of the NVBT is thus compliant with the latest guidance from US HUD and should

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[51] See Treatment of Community Solar Credits on Tenant Utility Bills, U.S. Department of Housing and Urban Development, August 4, 2022, available at: https://www.hud.gov/sites/dfiles/PIH/documents/Community%20Solar%20Credits%20in%20PIH%20Programs.pdf.

[52] See id., p. 2 ("If the credit reduces the cost of energy consumption by lowering actual utility rates, then the PHA will need to consider this information during its annual review of utility allowances.").

[53] See id., p. 2-3.

not result in lower utility allowances or higher tenant rents.[54]

Savings to Ratepayers for Title 24 Compliance

In rebuttal testimony, the California Building Industry Association ("CBIA") testified that community solar can play a vital role in providing a flexible compliance pathway for builders to meet California's aggressive building and energy efficiency standards. CBIA estimated that approximately 250-400 MW of community solar would be needed each year to meet builder's needs under existing regulations and that the need would expand to meet expanding requirements.[55] Witness Raymer also testified that increasing Title 24 requirements mean that community solar is becoming increasingly important to provide flexibility to homebuilders in order to control housing development costs.[56] While this benefit is hard to quantify given the lack of a viable program option in the service territories of the three IOUs, Witness Raymer's testimony provides an additional benefit to adoption of the NVBT. Allowing homebuilders flexibility in meeting Title 24 requirements beyond net metering will also save ratepayers money as the NVBT has higher TRC and RIM scores than the recently adopted Net Billing Tariff ("NBT") where the Commission found the adopted NBT garnered RIM scores of 0.35 to 0.58 and TRC scores of 0.78 to 1.03[57] versus the NVBT's RIM scores ranging from 0.81-0.92 and TRC scores ranging from 1.19-1.74.

The upshot of higher RIM scores for the NVBT over the NBT is that, for every MW of rooftop solar replaced by community solar plus storage, costs to ratepayers in meeting Title 24 requirements decrease. If one were to assume that NBT projects would provide the same avoided costs benefits per-

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[54] See id., pg. 2 (Factor 1.a).
[55] See Exhibit CBIA-01 (Raymer), p. 4, lns. 20 to p. 5, ln 2.
[56] See id. p. 5, lns. 3-16.
[57] See D.21-12-056, Appendix B, Modeling Inputs and Results, p. B6.

MW benefits as NVBT projects, the lower RIM scores of the NBT imply that one year of new home construction using NVBT projects in lieu of NBT projects could save between $102 and $419 million dollars in that year; over the 25 years that the 250-400 MW of projects deployed in year one serve homes, the savings will have a net present value of $1.089-$4.470 billion. These 1 year and lifetime savings values would grow rapidly given that CBIA is expecting the need for 250-400 of megawatts of community solar plus storage to occur *every year*. Creating the NVBT to facilitate Title 24 implementation and reduce the ratepayer costs of meeting building code requirements directly supports the Legislature's intent "to facilitate community renewable energy options that can help the state to cost-effectively meet the energy efficiency mandates in the California Building Standards Code."[58]

c. Response to Question 3 - Resources that will Participate in the NVBT are Distributed Energy Resources so the Use of the Avoided Cost Calculator to develop an Export Credit Rate is Reasonable

Question 3 states: If a community solar project has no on-site load and is installed "in front of the meter," is it appropriate for it to be considered a demand-side resource and compensated using values based on the Avoided Cost Calculator rather than least-cost best-fit evaluation through the integrated resource planning process? Identify which avoided cost values would be appropriate to apply and why they are appropriate.

<u>Net Value Billing Tariff facilities are Behind the Meter ("BTM") in a Manner Similar to Existing DER Programs</u>

Yes, it is appropriate for community solar plus storage projects to be considered a demand-side resource. The Renewable Energy Self Generation Bill Credit Transfer ("RES-BCT") program,[59] the Net

[58] AB 2316, Section 1(b).

[59] See, e.g., SCE's RES-BCT FAQ – question: "Are generators installed on greenfields or virgin sites eligible for RES-BCT?" ("Generators installed on greenfields or virgin sites can be served under RES-BCT…") available at: https://www.sce.com/business/generating-your-own-power/renewable-energy-self-generation-bill-credit-transfer/frequently-asked-questions; PG&E's RES-BCT FAQ – question: "How does RES-BCT work?" ("The generator account may or may not have electrical usage (load) on it.") available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/export-power/distributed-

Energy Metering Aggregation ("NEMA") program,[60] and the VNEM program[61] allow for interconnection of distributed energy resources behind a meter that does not have load beyond that of the generator and the exports from these facilities are treated as if they were behind a meter with non-project load. These programs are designed to expand access to DG to those who cannot install a DG facility on-site, which is exactly what the NVBT is seeking to do in response to the intent of AB 2316. All these programs have been appropriately evaluated using the suite of benefits identified in the ACC as available to distributed energy resources. CCSA proposes that NVBT facilities receive the same treatment to best effectuate the intent of the Legislature "to create a community renewable energy program so that all Californians, especially those unable to host a rooftop solar system, realize the benefits of distributed generation through a cost-effective program that provides benefits to all ratepayers."[62]

Even if the Net Value Billing Tariff Facilities are Determined to be In Front of the Meter, the Avoided Cost Calculator Remains the Applicable Tool for Evaluation and Compensation

Even if the Commission were to determine Net Value Billing Tariff projects are in front of the meter ("IFOM"), the Avoided Cost Calculator is still the applicable resource for evaluating and compensating the program's facilities. The means of interconnecting a resource to the distribution system does not determine its status as a DER – its interconnection within the distribution system does. For example, the CAISO defines a "distributed energy resource" as "any resource located on the

generation-handbook/net-energy-metering/res-bct-program.page.

[60] See, e.g., PG&E NEM Aggregation (NEMA) Frequently Asked Questions, Section II. Definitions, "What is a Generating Account?" response in relevant part: "A Generating Account is the account that is connected to the renewable generator. It may or may not have load other than that of the generator." available at: https://www.pge.com/includes/docs/pdfs/b2b/newgenerator/NEMA_faq.pdf.

[61] See, e.g., PG&E's Virtual Net Metering website, noting "[t]he generating account can have no load other than that required for the renewable generating system."

[62] AB 2316, Section 1(a).

distribution system, any subsystem thereof, or behind a customer meter in a Utility Distribution Company or a Metered Subsystem."[63] As another example, the Commission's DER Action Plan defines DERs as: Distributed Energy Resources: (DERs) include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, time variant and dynamic rates, flexible load management, and demand response technologies. *Most DERs are connected to the distribution grid behind the customer's meter (BTM), and some are connected in front of the customer's meter (FTM)*.[64] (emphasis added) In both instances, interconnection of the resource IFOM or BTM has no bearing on status as a DER, rather it is the fact that the system is installed within the distribution system that is key. Because resources under the NVBT will be required to interconnect to the distribution system, resources participating in the NVBT, whether they are deemed to be BTM or "IFOM", are properly considered distributed energy resources.

As described above, the Commission found that "the avoided costs determined in the Avoided Cost Calculator are the utilities' marginal costs of providing electric service to customers. Those costs can be avoided when the demand for energy decreases because of distributed energy resources, and are, thus, the benefits of using distributed energy resources."[65] All seven of these benefits accrue to participating and non-participating customers as they are reductions in demand that avoid utility costs.

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[63] See California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, May 1, 2023, Appendix A.

[64] California Public Utilities Commission Distributed Energy Resources Action Plan Aligning Vision and Action (April 2021), p. 23. see, also, 18 CFR Sec. 35.28(b)(10)(defining a distributed energy resource as "any resource located on the distribution system, any subsystem thereof or behind a customer meter."); see, also, Electric Power Research Institute, The Integrated Grid: A Benefit-Cost Framework, issued February 12, 2015 at pg. xvii, (defining Distributed Energy Resources as electricity supply resources that…are "Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69kV) and one of three other criteria such as "generate electricity using any primary fuel source and store energy and can supply electricity to the grid from that reservoir."), available at: https://www.epri.com/research/products/000000003002004878.

[65] See id.

Notably the ACC-based credit under the NBT created in D.22-12-056 is for the energy exported by the generator, meaning that the exported energy is *not* modifying load at that particular service location, but is modifying load on the circuit where the energy is exported. CCSA is asking for similar treatment to create a program that is compliant with AB 2316 both in the scalability and scope of customers it can serve by utilizing avoided costs to compensate subscribers for their capacity interest in the facility.

Based on the fact that facilities participating in the NVBT are DERs that are modifying load on the distribution circuit where they are interconnected, it is appropriate to compensate subscribers to these resources for the full value stack identified by the ACC: generation capacity, energy, transmission and distribution capacity, ancillary services, Renewables Portfolio Standard, greenhouse gas emissions, and high global warming gasses.[66] NVBT resources will result in reductions in load at the distribution system level in the same manner as other distributed energy resources participating in various Commission programs that connect in front of the meter or behind a customer meter. Thus, inclusion of these benefits in the NVBT's export compensation rate is reasonable because the Commission has already found that "the avoided costs determined in the Avoided Cost Calculator are the utilities' marginal costs of providing electric service to customers. Those costs can be avoided when the demand for energy decreases because of distributed energy resources, and are, thus, the benefits of using distributed energy resources."[67] Finally, the Commission has not limited compensation to demand side resources based on the way the facility connects to the grid and it should not do so here.

[66] See D.22-12-056, pg. 59.
[67] See id.

<u>The Commission has Been Continuously Evolving Resource Planning and Procurement So That All Sourced Resources are Consistent with a Least Cost Best Fit Portfolio</u>

The Least Cost, Best Fit ("LCBF") concept was developed in the Long-Term Planning Proceeding to provide "criteria for the rank ordering and selection of least-cost and best-fit renewable resources on a total cost basis to comply with the California Renewables Portfolio Standard ("RPS") Program"[68] as required by Sec. 399.13(a)(5). With the passage of SB 350 (de Leon, 2015) the state began an Integrated Resource Planning for the first time in 20 years to ensure that state policy goals were met reliably while minimizing cost. The ACC, in turn, has evolved to be increasingly harmonized with this global planning process.[69] A key strength of the Net Value Billing Tariff is how its compensation and design are tied to the ACC and its evolution, and, thereby, are tied to the IRP and evolution towards greater and greater alignment of the ACC with the IRP. In short, the ACC has been modified to support deployment of a least cost, best fit portfolio and continues to be refined to achieve that outcome.

d. Response to Question 4 - Timeline of Implementation, Contracting, Construction, Interconnection and Utility Billing System Upgrades

Question 4 states: For new community renewable energy program proposals not based on existing or modified programs, describe the specific timelines for the contracting, construction, interconnection, subscription and billing for such

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[68] D.04-07-029, p. 2.

[69] Orders in R.14-10-003 repeatedly reference harmonization between the ACC and IRP. D.16-06-007 stated that "we find that future phases of cost-effectiveness work…are high priority for the Commission in order to…prepare for integrated resource planning envisioned in R.16-07-002 (pg 19), As the Commission states in D.19-05-019 the Commission adopted use of the GHG adder from the Integrated Resource Planning process into the ACC and stated that "the Commission's vision is alignment between the cost-effectiveness work in this proceeding and the anticipated efforts to develop a Common Resource Valuation Method in the Integrated Resource Planning proceeding and this is the first step"(pg.57)-in D. 22 05-002 The Commission stated that a "theme throughout this decision is the importance of aligning the Avoided Cost Calculator with the Integrated Resource Planning proceeding. The intention of the Commission in adopting such an alignment is to ensure that all resources are evaluated equally, be they distributed energy resources or suppl-yside resources. To ensure such alignment, this decision adopts the policy that the update of the Avoided Cost Calculator will rely on an adopted Reference System Plan or Preferred System Plan"(pg.3).

new programs.

CCSA's proposed NVBT will deliver solar plus storage assets to California's distribution grid much more quickly than any of the existing programs and much more quickly than new utility-scale renewable resources can be developed. As load modifiers, NVBT projects will provide on-peak delivery of energy and resource adequacy benefits without an extended contracting process or multi-year CAISO deliverability studies which are presently stymieing development of wholesale resources.

<u>**Development Timelines (Contracting, Construction, Interconnection)**</u>

Witness Smithwood provided a detailed table in his amended testimony describing the typical development process for a community solar project under the NVBT.[70] While the details will vary from company to company, community solar plus storage projects under NVBT can be expected to be online no later than a year after receiving their permits and executing their interconnection agreement.

Table 9. Illustrative Development Timelines

Development Step	Time for Step	Cumulative Time
Secure site control of building/landowner	Project specific	
Apply for Interconnection	<1 month	<1 month
Interconnection study complete	2 months (Fast Track) – 6 months (independent study)	2-6 months
Project permitting	6-24 months, less if only a building permit is required	3-31 months
Distribution system upgrades (if applicable)	6-24 months	Project construction would roughly coincide with completion of these upgrades
Project constructed and operating	Completed 12 months from permits and interconnection agreements finalized	9 to 43 months

[70] See Exhibit CCSA-001 (Smithwood), Table 6, Illustrative Commercial Development Timelines, p. 127.

Specific steps in the development process such as project siting, interconnection, permitting, and construction, are similar between DAC-GT, CSGT, and GTSR programs and the proposed NVBT. However, there are very significant differences, measured in *years*, between the timelines. These differences include the time required to complete interconnection studies, and the process for a project to enter the program.

NVBT projects, particularly projects with the community solar sited on rooftops and storage in adjacent parking lots, could be ready to participate in the tariff in a matter of weeks, or months after the tariffs are published, while projects seeking to participate in existing programs and provide resource adequacy benefits will require up to 2 years, or even longer. Projects must have any necessary non-ministerial permits and completed interconnection studies, or a signed interconnection agreement, prior to participating in either the proposed NVBT or the existing programs. In the existing programs, projects must also go through a CAISO deliverability study—a process that can take more than two years— to provide resource adequacy. The cost and time required for deliverability studies is why all the projects currently in the existing programs are energy-only and offer no resource adequacy or reliability benefits.

In contrast, NVBT projects connecting to the distribution grid under Rule 21 will have access to Fast Track, Independent Study, or Distribution Group Studies through the local utility. Once online, the projects will be constrained by the economics of the ACC to deliver energy when it is most needed. As load modifiers, the projects will reduce the resource adequacy requirements of load serving entities under the same framework as other distributed energy resources. No additional resource adequacy or capacity contracts are required to realize the on-peak energy and grid reliability benefits of NVBT projects.

In addition to the significant interconnection study time required prior to entering any of the existing green access programs, projects must also participate in a solicitation, negotiate a contract, and in the case of the utility programs, wait for Commission approval of the contract via an advice letter. Currently, solicitations for the green access programs are held semi-annually, though SCE and PG&E's proposals would change that cadence to once per year—again, adding additional months of development time and uncertainty for projects. The NVBT was designed to reduce the development uncertainty that has hobbled existing programs by eliminating burdensome solicitations, paying a reasonable price that supports project economics while avoiding cost shifts, and providing developers a clear line-of-sight and confidence to invest in interconnection and permitting.

<u>Billing Timeline</u>

As Arcadia outlined in their Opening Brief, the utilities must perform four steps to ingest data from projects and apply bill credits to customer bills: 1) calculate the total value of credits from the project for the month; 2) allocate those credits to subscribers in accordance with the most recent allocation list; 3) apply credits to each customer, net of the subscription fees; and 4) remit subscriber fee payments to the project. These processes can be done manually, in whole or in part, but they should be automated as a program scales so as to limit billing cost and improve speed and accuracy. Implemented billing system improvements to automate these four steps have been done in several states in short timeframes.

In New York, Consolidated Edison Company of New York, Inc. ("Con Edison") automated the Value of Distributed Energy Resource (VDER) tariff calculation in less than a month[71] (i.e., Step 1,

[71] See New York Public Service Commission, Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Consolidated Edison Company of New York,

described in the paragraph above). During this phase, Con Edison also created a process to manually allocate bill credits to customer bills.[72] Con Edison eventually automated the process of applying bill credits, which the utility anticipated would take about one year.[73] The next two steps (applying the net credit and remitting payment to the project developer) took Con Edison approximately 12 months.[74]

While Con Edison performed each upgrade in less than a year, billing system upgrades can occur in parallel rather than sequentially. Such was the case in Illinois, where Commonwealth Edison Company ("Com Edison") performed all four phases of net crediting implementation within twelve months. After passage of the Climate and Equitable Jobs Act at the end of 2021, Com Edison spent about six months working to calculate the new bill credit and apply the credit to customer bills, which went into effect on June 1, 2022.[75] Com Edison then finalized the application of net crediting, along with the process to remit payment to the project developer, in January 2023[76].

Particularly because these automation processes can happen in parallel, as was the case in Illinois, one year is a reasonable expectation for the timeline to implement billing system improvements.

Inc. Automation and Billing Report, p. 3. (Con Ed's plan was filed on November 13, 2017 and identified completion of Phase I of the billing system upgrades, including automating the calculation of the bill credit rate, by the end of that calendar year).

[72] Ibid, pp. 3-5.

[73] Ibid, pp. 5

[74] See New York Public Service Commission, Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources, Consolidated Edison Net Crediting Report, filed March 31, 2022 (The report provides the investments for the 2021 calendar year, revealing that almost all of the investments of implementing the final two components of net crediting took place during the course of the 2021 calendar year.)

[75] Commonwealth Edison Company, Rider POGCS, Parallel Operation of Retail Customer Generating Facilities Community Supply, 1stRevised Sheet No. 344.12.

[76] See ComEd Community Supply Subscription Handbook, *available at* https://www.comed.com/SiteCollectionDocuments/SmartEnergy/CS_Project_Handbook-Ch_1-Terms_Definitions.pdf (definition of "Community Supply Subscription Billing" added in January 2023 to reflect new net crediting product offering)

Customer Subscription Timeline

One of the myriad advantages of the NVBT is that subscription risk is borne by the project developer, not the utility nor by ratepayers. Simply put, the project doesn't get paid if it isn't subscribed and the project has a strong financial incentive to be fully subscribed at all times. CCSA members have had a variety of experiences subscribing customers on projects in many different states. Generally, projects are subscribed in a matter of weeks or months, depending on factors such as the split between residential and commercial subscribers, or the amount of capacity reserved for low- or moderate-income subscribers and the income verification requirements. Project financiers frequently impose minimum subscription level requirements at certain project life milestones such as mechanical completion or commercial operation. Meeting these requirements means that projects will begin to be subscribed in advance of the project reaching commercial operation, typically 6 months or more in advance of commercial operation of the project. Projects will be fully subscribed by the time they reach commercial operation, as required in CCSA's NVBT proposal and as is common practice in other markets.

Program Implementation Timeline

Witness Smithwood provided a timeline that incorporated project, rulemaking and program timelines in his opening testimony. That timeline has been updated here to reflect the current rulemaking timeline and has added billing and billing automation timelines.

Table 10. Illustrative Program Implementation Timeline

Date	Event	Notes
August 2023	Reply Comments to June 24th Ruling on Cost-Effectiveness are filed and record is closed	August 10, 2023
September 2023	California Application due to US EPA for Solar for All competitive grant program Guidance for CEC Distributed Electricity Back Up Assets program adopted	EPA Solar for All due date is September 26, 2023
Q4 2023	Final Decision Adopted	
Q1 2024	Staff releases consumer disclosure forms and registration forms for community solar market participants and starts accepting registration applications Utilities convene a billing workshop to identify system updates and costs and establish an ongoing billing working group for Subscriber Organizations and Subscription Managers.	Utilities should include estimates of costs to implement billing changes with their tariff filings.
Q1 2024	Utility tariff filings approved by CPUC	As prepared with non-ministerial permits and a distribution interconnection agreement, projects can enroll in the program once tariffs are adopted
March, 2024	EPA's anticipated notification of selections	EPA will have time to review California's application and the final decision in this docket and make an award.

March 31, 2024	Deadline for CPUC to report to Legislature what actions it took with respect to existing programs and whether a new program will be implemented	March 31, 2024, as required in AB2316.
Q2 2024	Deadline for CCAs to notify Commission whether they plan to create a program	180 days from establishment of program in July 2023 (per 769.3(b)(2)(B))
July 2024	EPA anticipated notification of awards.	
As early as Q3, 2024	Customer recruitment begins	Subscriber Organizations and Subscription Coordinators must have filed for registration prior to beginning to market projects
Q3 2024	Utility Participant Allocation List forms ready from utilities for use	
End of Q3 2024	Utilities prepared to begin to receive initial subscriber allocation lists	Projects demonstrate they have received approval of registration application

III. CONCLUSION

The record established in this docket demonstrates that the NVBT is beneficial to ratepayers by supporting the deployment of grid harmonized resources that can meet California's need for firm resources during the evening ramp. It avoids cost shifts by grounding compensation to subscribers in the avoided costs generated by the facility they subscribe to. The NVBT also has numerous other benefits that save ratepayers money and avoid public health impacts from use of fossil fuel resources. CCSA encourages the Commission to embrace the NVBT as the foundation for a cost-effective community renewables program that will benefit all Californians.

Respectfully submitted on July 31, 2023.

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Appendix A

Workpapers & Assumptions

Workpapers are available at:

https://drive.google.com/drive/u/0/folders/1UcqdHG3k1UtLbYTN4f3WT0sChA7Y5CLC

Cost of Renewable Energy Spreadsheet Tool (CREST) Assumptions and Methodology[1]

Locational Performance Inputs by Mount Type

Input	Unit	PG&E	SCE	SDG&E
Location	N/A	Fresno	San Bernadino	San Diego
Mount Type/Applicable PV System Case	N/A	Ground (All)	Ground (All)	Ground (All)
Tilt	Degrees	0	0	0
Azimuth	Degrees	180	180	180
DC-AC/Inverter Loading Ratio	N/A	1.34	1.34	1.34
PVWatts-Generated DC Capacity Factor	%	**22.4**	**22.70**	**21**
Annual Degradation	%/yr	**0.7**	**0.7**	**0.7**

Interconnection Cost Assumptions

Input	Unit	PG&E	SCE	SDG&E
Assumed Upfront Costs (Low Case)	$/kW PV	100	100	100
Assumed Upfront Costs (Base Case)	$/kW PV	250	250	250
Assumed Upfront Costs (High Case)	$/kW PV	400	400	400
WDAT IC O&M Costs	%/month of upfront IC	0.86	0.34	0.28
IC O&M Costs	$/kW-yr	10.32	4.08	3.36

Project Revenue Sharing by Offtaker Type (All Utilities)

ITC %	Low-Income Residential			Non-Low-Income Residential			Commercial and Industrial (C&I)			Total % Revenue Share
	% of Output	*Revenue (Rev.) % Share*	*Weighted (Wtd.) % Share*	*% of Output*	*Rev. % Share*	*Wtd. % Share*	*% of Output*	*Rev. % Share*	*Wtd. % Share*	
30%	51%	20%	10.2%	10%	10%	1.00%	39%	5%	1.95%	**13.2%**
50%	51%	25%	12.75%	10%	10%	1.00%	39%	5%	1.95%	**15.7%**

[1] CREST models contained in workpapers include information for rooftop facilities. However, those results were not updated, utilized, or relied upon in developing CCSA's comments.

Capital Cost, Operating Cost and Performance Inputs by Modeled Project Type

Input	Unit	6.7 MW_{DC}, 5 MW AC, Single-Axis Tracking, No Storage		6.7 MW_{DC}, 5 MW_{AC}, Single-Axis Tracking, with Storage	
Investment Tax Credit (ITC) Value	%	30%	50%	30%	50%
Modeled Program	N/A	DAC-GT	DAC-GT	NVBT	NVBT
Solar PV Installed Capital Cost (Assumes 2024 Financial Close)	$/kW_{DC}$	1,258	1,258	1,258	1,258
Incremental Shared Solar Customer Acquisition Upfront Capital Cost[i]	$/kW_{DC}$	100	100	100	100
Energy Storage Modeled Duration	Hours	N/A	N/A	4	4
Energy Storage Modeled Size	kW/ kWh	N/A	N/A	5,000/ 20,000	5,000/ 20,000
Energy Storage Installed Capital Cost (Assumes 2024 Financial Close)	$/kWh	N/A	N/A	420	420
Fixed Non-CSS O&M Expense, Yr 1[ii]	$/kW-yr	11.00	11.00	11	11
Fixed CSS O&M Expense, Yr 1	$/kW-yr	22.00	22.00	22.00	22.00
Storage O&M, Yr. 1 (Energy Storage System Capacity)	$/kW-yr	N/A	N/A	4.17	4.17
O&M Cost Inflation	%	3	3	3	3
Insurance, Yr. 1 (% of Total Cost)	%	0.6	0.6	0.6	0.6
Project Management Yr. 1	$/yr.	20,000	20,000	20,000	20,000
Property Tax or PILOT	$/kW	0	0	0	0
Land Lease	$/yr	42,857	42,857	42,857	42,857
Non-O&M OpEx Annual Escalation Factor	%	2	2	2	2
Decommissioning Cost	$/kW	20	20	20	20
Bond Expense for Decommissioning	% of Decomm. Cost	2	2	2	2
Storage Replacement Year	Project Year	N/A	N/A	15	15
Storage Replacement Cost	$/kWh ESS	N/A	N/A	206	206
Solar Inverter Replacement Year	Project Year	12	12	12	12
Solar Inverter Replacement Cost	$/kW PV	21	21	21	21

Financing Inputs by Modeled Project Type

Input	Unit	6.7 MW_{DC}, 5 MW AC, Single-Axis Tracking, No Storage		6.7 MW_{DC}, 5 MW_{AC}, Single-Axis Tracking, 20 MWh Storage	
Investment Tax Credit (ITC) Value	%	30%	50%	30%	50%
Modeled Program	N/A	DAC-GT	DAC-GT	NVBT	NVBT
% Debt (% of Hard Costs)[iii]	%	44[iv]	27-28	40-41	24[v]
Debt Term	years	15	15	15	15
Interest Rate on Term Debt	%	6.8	6.8	6.8	6.8
Lender's Fee (% of Total Borrowing)	%	2	2	2	2
Required Minimum Annual Debt Service Coverage Ratio (DSCR)	DSCR	1.00	1.00	1.00	1.00
Required Average DSCR	DSCR	1.25	1.25	1.25	1.25
Target After-Tax Equity IRR	%	10.4	10.2	10.4	10.2
Federal Income Tax Rate	%	21	21	21	21
State Income Tax Rate	%	8.84	8.84	8.84	8.84

Project Compensation

Case Group	Ground-Mounted, Single-Axis Tracking With Storage ($/kWh)					
Program	NVBT					
Project Year	PG&E		SCE		SDG&E	
	20 yr	25 yr	20 yr	25 yr	20 yr	25 yr
1	0.208	0.208	0.227	0.230	0.281	0.284
2	0.210	0.210	0.229	0.232	0.282	0.285
3	0.210	0.210	0.229	0.232	0.281	0.284
4	0.206	0.205	0.224	0.227	0.275	0.278
5	0.206	0.206	0.224	0.227	0.275	0.278
6	0.201	0.201	0.220	0.223	0.272	0.275
7	0.202	0.202	0.221	0.224	0.272	0.275
8	0.203	0.202	0.221	0.224	0.271	0.274
9	0.201	0.201	0.219	0.222	0.269	0.272
10	0.200	0.200	0.218	0.220	0.267	0.270
11	0.199	0.199	0.217	0.219	0.266	0.269
12	0.199	0.199	0.216	0.219	0.265	0.268
13	0.199	0.198	0.216	0.218	0.264	0.267
14	0.199	0.198	0.215	0.218	0.263	0.266
15	0.199	0.199	0.215	0.218	0.263	0.266
16	0.249	0.248	0.272	0.275	0.334	0.337
17	0.247	0.247	0.270	0.273	0.332	0.335
18	0.246	0.246	0.268	0.271	0.330	0.333
19	0.245	0.245	0.267	0.270	0.328	0.331
20	0.244	0.244	0.266	0.269	0.326	0.330
21	0.084	0.244	0.083	0.268	0.088	0.329
22	0.088	0.245	0.087	0.269	0.092	0.329
23	0.092	0.247	0.091	0.270	0.096	0.330
24	0.096	0.249	0.095	0.272	0.100	0.331
25	0.100	0.251	0.099	0.273	0.104	0.332
26	0.105	0.102	0.104	0.102	0.109	0.108
27	0.109	0.107	0.108	0.107	0.114	0.113
28	0.115	0.112	0.114	0.112	0.120	0.119
29	0.120	0.117	0.119	0.117	0.125	0.124
30	0.126	0.123	0.125	0.123	0.131	0.130

Derivation of Ongoing Billing System Capital Expenses Costs Assumed Borne by Project Owners

Utility	PG&E	SCE	SDG&E
Total Allocated MW (Share of 4 GW)	1,784	1,827	389
Estimated Upfront Capital Expenditure Required for Billing System Upgrade[vi]	$10,000,000	$12,500,000	$13,000,000
Total Cost/Year Over 20-Year Export Compensation Rate (ECR) Lock Term	$500,000	$625,000	$650,000
Total Cost/Year Over 25-Year ECR Lock Term	$400,000	$500,000	$520,000
Total Cost/kW/Year For Input Purposes Only (20-Year ECR Lock)	**$0.28**	**$0.34**	**$1.67**
Total Cost/kW/Year For Input Purposes Only (25-Year ECR Lock)	**$0.22**	**$0.27**	**$1.34**

Derivation of Ongoing Billing System Capital Expenses Costs Assumed Borne by Project Owners

Utility	PG&E	SCE	SDG&E
Total Allocated MW	1,784	1,827	389
Estimated Upfront Capital Expenditure Required for Billing System Upgrade	$10,000,000	$12,500,000	$13,000,000
Annual Billing System O&M/Project Year	$500,000	$120,000	$1,500,000
Total Cost/kW/Year For Input Purposes Only (Assuming 25-Year ECR Lock Term)	**$0.22**	**$0.27**	**$1.34**

[i] Value provided herein assumes low case upfront interconnection input value, and is incorporated into installed cost estimate above, but varies based upon low/base/high interconnection case

[ii] Value provided herein assumes inclusion of annual interconnection O&M values

[iii] These ranges represent the variation between the 20 and 25 year ECR duration

[iv] This value is unchanged between the 20 and 25 year ECR duration

[v] This value is unchanged between the 20 and 25 year ECR duration

[vi] Specific citations included in Kennerly CREST model work papers

NVBT Assumptions and Methodology for Cost Effectiveness Analysis

Avoided Costs

All avoided costs used in the analysis derive from the 2022 Avoided Cost Calculator version 1b (ACC).

Tariff Modeling

As also described in the Amended Testimony of Mr. Fulmer, CCSA used the following assumptions and tools to generate illustrative NVBT peak and off-peak rates for its analysis.

General Assumptions

Term: Analysis was performed over 25- and 20-year terms. For the 25-year cases, tariff values reflect 25-year levelization periods. For 20-year cases, tariff values reflect 20-year levelization periods. The levelization period starts in 2024.

Peak Period: 5-9 pm Pacific Standard Time for the months of July-September. This was chosen to capture over 99% of the 2022 generation capacity avoided costs in the ACC. As discussed in Witness Smithwood's amended testimony, the peak period may shift over time, but this was not directly modeled for purposes of this analysis.

Value Stack Components

<u>Energy</u>

The Energy component of a NVBT facility subscriber's bill credit will be the day ahead market prices from the California Independent System Operator energy market. As a proxy for those prices, CCSA relied on hourly values from the ACC for the following three avoided cost components: energy, losses, and cap and trade.

<u>Generation Capacity</u>

Avoided Costs Included: Generation Capacity

Location Variation: By IOU

Peak Period Rate: Levelized annual ACC values divided by number of peak period hours (368)

Off-Peak Period Rate: Zero

<u>Transmission and Distribution</u>

Avoided Costs Included: Transmission and Distribution

Location Variation: By IOU and Climate Zone; however only PG&E has annual distribution avoided costs that vary by climate zone; the other two IOUs do not have climate zone variation

Peak Period Rate: Levelized annual ACC values divided by number of peak period hours (368)

Off-Peak Period Rate: Zero

PG&E Climate Zone Modeled: 13. Selected to match solar+storage project location. (Refer to Solar + Storage Project Modeling and Dispatch for more details on project locations.)

Environmental Value

Avoided Costs Included: GHG Adder, Rebalancing, and Upstream Methane Leakage

Location Variation: By IOU

Annual Average Rate: Levelized annual ACC values

Peak to Off-peak Ratio: Ratio of average peak period and off-peak period hourly avoided costs in year 2022. Resulting values are:

	Peak-to-Off-peak Ratio
PG&E	2.05
SCE & SDG&E	2.04

Summary Table of Modeled Value Stack Components

Value Element	Source	Peak Period	Location Variation	Escalation	Peak to Off-Peak Price Ratio
Energy	ACC Energy, ACC Losses, and ACC Cap & Trade	Values vary hourly	By Zone	N/A	N/A
Generation Capacity	ACC Generation Capacity	5 pm - 9 pm PST July - September	By IOU	Levelized over term	Zero off-peak price
Transmission and Distribution	ACC Transmission and ACC Distribution	5 pm - 9 pm PST July - September	By IOU and Climate Zone	Levelized over term	Zero off-peak price
Environmental Value	ACC GHG Rebalancing, ACC GHG Adder, methane leakage adder	5 pm - 9 pm PST July - September	By IOU	Levelized over term	Average peak to off peak avoided cost ratio

Solar + Storage Project Modeling and Dispatch

As also described in the Amended Testimony of Mr. Fulmer, CCSA used the following assumptions and tools to model solar + storage projects for purposes of its analysis.

Solar Project

Size	5 MW ac
Technology	Ground-mount, single-axis tracking
Hourly Profile Source	PVWatts (see project location table below)
Output Degradation	0.7%/year

Storage Project

Capacity	5 MW
Duration	4-hour (20 MWh)
Round-trip Efficiency	90%
Degradation	2%/year
Replacement	Replaced after 15 years
Dispatch	Solar Value Stack Calculator algorithm*

*Solar Value Stack Calculator is an Excel model derived from a model used to estimate compensation for the New York Value of Distributed Energy Resources (VDER) program. New York-specific inputs were deleted and replaced by the relevant inputs described in this document. The storage dispatch logic was retained. The dispatch logic attempts to maximize the NVBT revenues the project receives.

Project Location

	Project Location	Climate Zone
PG&E	Fresno	13
SCE	San Bernadino	10
SDG&E	San Diego	7

Cost Effectiveness Scores

As directed, the methodology reflects the California Standard Practice Manual (SPM) from October 2001.

Term

Two terms were analyzed: 20-year and 25-year starting in 2025.[1]

Benefits

All cost effectiveness tests rely on the same avoided cost benefits using the ACC. The solar + storage project output in MWh was multiplied by the hourly avoided costs for each IOU in $/MWh. (See above description of solar + storage project.) Avoided costs derive from the ACC using all avoided cost components except ancillary services.

The calculation was performed using the Solar Value Stack Calculator model.

Costs

<u>Total Resource Cost (TRC)</u>

Per the standard practice manual, the total resource cost test "measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." Costs derive from a CREST analysis performed by Mr. Kennerly,[2] which includes the following:

- Costs to develop the solar + solar project, including all capital costs, O&M, financing costs, etc.

[1] Note the start year differs from the levelization period used to derive the NVBT peak and off-peak rates. This is consistent with the NVBT program design that would use the same levelized values for projects developed in a given two-year period because the ACC is only updated every two years.
[2] The CREST model is included in workpapers submitted with these Comments. Appendix A contains a discussion of assumptions that were input into the CREST model.

    - Two cost scenarios are modeled, one with a 30% ITC and one with a 50% ITC
- Costs to administer the program, including IOU billing costs discussed in Mr. Kennerly's surrebuttal testimony

The only difference between the costs included in this analysis and presented in Mr. Fulmer's surrebuttal testimony is that it excludes the bill credits paid to participants. Such costs should be excluded because bill credits are effectively a transfer between the utility and the participant. From the utility side it is a cost and from the participant side a benefit. When doing the summation of the two, it cancels out.

Rate Impact Measure (RIM)

The RIM includes utility costs and lost revenues due to sales reductions. Because the solar + storage project is assumed to be not offsetting loads beyond those of the project behind the meter, and MRW did not model the project as behind-the-meter that would have onsite load, there are no lost sales revenues included in the analysis. The utility costs are the costs of the bill credits applied to subscriber utility bills at the NVBT rates.

For purposes of this analysis, NVBT costs are the product of:

- Illustrative NVBT tariff rates calculated using the assumptions listed above under Tariff Modeling, and
- Solar + storage project output as modeled using assumptions discussed above under Solar + Storage Project Modeling and Dispatch

Note, there are no separate line items for participant payments or program administration costs in this test. This is because per the program design, those costs are paid from the NVBT revenues. Including them again would constitute double counting.

Program Administrator Cost (PAC)

Since there is no separate third-party administrator, this is a utility cost test. Per the SPM, the utility costs included in this test are the same as the RIM, except it excludes the impact of lost revenues from load reductions. Since no subscriber load reductions have been modeled, the PAC and RIM results are identical.

Benefit-Cost Ratios

Once annual benefits and costs are quantified, they are expressed as a net present value (NPV). The NPV discount rate is equal to the IOU weighted average cost of capital in the ACC, which is 7.52%. The NPV of the benefits is divided by the NPV of the costs to calculate a benefit-to-cost ratio, also called the cost effectiveness "score." Higher scores indicate greater cost effectiveness (more benefits relative to costs).

Net Revenue Impact, Rate Impact, and Residential Bill Impact

Per the SPM, quantification of revenue impacts (net of benefits) and rate impact derive from CCSA's RIM analysis. To perform these calculations, a program size in MW or GW must be assumed. Since the ultimate program size is unknown, the results are presented on a unitized basis, either per MW or per GW as described in further detail below.

Net Revenue Impacts

Net Revenue Impacts are calculated on a lifecycle basis for the entire term of the analysis, either 20 or 25 years.

Lifecycle net revenue impacts are presented on an NPV basis. The NPV of the benefits calculated to do the RIM benefit-cost ratio is subtracted from the NPV of the costs. The resulting value is divided by 5 MW, the assumed project size, to provide a unitized per MW value for each IOU.

Rate Impact

Rate impacts are assessed using the lifecycle revenue impact measure described in the SPM, expressed on a per kWh basis. Rate impacts are assessed assuming a 1 GW program size with the allocation of the program MWs to the IOUs per the following table. The allocation matches that used by Mr. Kennerly in assessing the IOU billing costs. Effectively, the unitized per MW lifecycle net revenue impacts described above are multiplied by these MW values for each IOU.

	Program Size (MW)
PG&E	446
SCE	457
SDG&E	97
Total	1000

The resulting net revenue impacts are then divided by the discounted IOU annual sales. The discounting is done over the same term and using the same discount rate as used to calculate the NPV of the benefits and costs. Forecasted sales are taken from the 2022 Integrated Energy and Policy Report (IEPR) from the California Energy Commission. Values after 2035 are extrapolated at the growth rate from the final year of the IEPR forecast period (growth from 2034 to 2035).

Residential Bill Impact for Non-Participants

To estimate the bill impact for non-participant residential customers, the rate impact described above is multiplied by the assumed typical monthly usage for a residential customer. We assumed, for simplicity of the analysis, that the typical monthly usage is 500 kWh for each IOU.

Residential Bill Impact for Participants

Bill impacts for participants were assessed using values from the first year of the analysis period (2025) instead of the entire term. The 2025 average NVBT revenues in $/kWh were calculated. For the 30% ITC case, subscribers were assumed to receive 20% of the NVBT credit. For the 50% ITC case, subscribers were assumed to receive 25% of the NVBT credit. To translate the bill credit rate to a bill impact, the bill credit rate described above is multiplied by the assumed typical monthly usage for a residential customer, i.e. 500 kWh/month.

DAC-GT Assumptions and Methodology for Cost Effectiveness Analysis

Avoided Costs

All avoided costs used in the analysis derive from the 2022 Avoided Cost Calculator version 1b (ACC).

Solar Project Modeling and Dispatch

CCSA used the following assumptions and tools to model solar projects for purposes of its analysis.

Solar Project

Size	5 MW ac
Technology	Ground-mount, single-axis tracking
Hourly Profile Source	PVWatts (see project location table below)
Output Degradation	0.7%/year

Project Location

	Project Location	Climate Zone
PG&E	Fresno	13
SCE	San Bernadino	10
SDG&E	San Diego	7

Cost Effectiveness Scores

As directed, the methodology reflects the California Standard Practice Manual (SPM) from October 2001.

Term

Two terms were analyzed: 20-year and 25-year starting in 2025.

Benefits

All cost effectiveness tests rely on the same avoided cost benefits using the ACC. The solar project output in MWh was multiplied by the hourly avoided costs for each IOU in $/MWh. (See above description of solar project.) Avoided costs derive from the ACC using all avoided cost components except ancillary services.

The calculation was performed in Excel.

Costs

<u>Project Costs</u>

Costs to develop the solar project, including all capital costs, O&M, financing costs, etc. were supplied by Mr. Kennerly from a CREST analysis. Assumptions were consistent with the solar portion of the solar+storage project modeled for the NVBT program.[1]

[1] The CREST model is included in workpapers submitted with these Comments. Appendix A contains a discussion of assumptions that were input into the CREST model.

Two cost scenarios were modeled, one with a 30% ITC and one with a 50% ITC.

Program Administration Costs

CCSA calculated a weighted average cost of all CCA and IOU program administrators except CalChoice, which was not included because it has the smallest allocation and its program has not yet launched, leaving limited data for the analysis. CalChoice program administration costs were effectively assumed to be the same as SCE. Cost categories include Program Management, IT, Marketing, Procurement, and CCA integration for PG&E. Program evaluation is not included per the SPM.

The analysis was performed in the following steps.

1) Identify a source of program administration cost for a single year. The source data for each administrator is listed in the table below. They reflect recent program budgets for the IOUs. For the CCAs, the data reflects recent actual costs or budgets if actual costs are not available.

Program Administrator	Data Year	Budget or Actual	Source Document
PG&E	2024	Budget	Advice Letter 6905-E-A
SCE	2024	Budget	Advice Letter 5002-E
SDG&E	2022	Budget	SDG&E Testimony[2]
CleanPowerSF	2022	Actual	Advice Letter 26-E
EBCE	2022	Budget	Data Request Attached to Rebuttal Testimony
MCE	2022	Actual	
PCE	2022	Budget	
SJCE	2022	Actual	
CPA	2022	Actual	
SDCP	2023	Budget	Advice Letter 10-E

2) Because program administration costs are assumed to vary based on the size of the program, convert the program administration cost to $/MW. This involved assuming the amount of MW of program size that underly the utility and CCA program administration cost data. For the most part, CCSA assumed the budget reflects the entire DAC-GT program capacity allocation, except for SDG&E. For SDG&E, SDCP has recently been allocated most of the DAC-GT program capacity. CCSA assumed SDG&E's 2022 budget reflects the entire allocation to the SDG&E service territory (18 MW). See the table below under step 4 with the remaining program capacity allocations.
3) Convert the single year to an annual forecast for the analysis term. CCSA assumed the significant IT cost in SCE's budget were a one-time cost. Otherwise, no escalation was applied to the costs.
4) Create a weighted average of the program administration costs for each IOU service territory. Weighting factors reflect the amount of MW allocated to each program administrator as follows.

Program Administrator	Program Capacity Allocation (MW)
PG&E	52.32
CleanPowerSF	1.826
EBCE	5.726
MCE	4.646

[2] Filed May 31, 2022, Table 1-HB, p. 32.

PCE	3.736[3]
SJCE	1.736
TOTAL PG&E TERRITORY[4]	**69.99**
SCE[5]	57.81
CPA	12.19
TOTAL SCE TERRITORY	**70**
SDG&E	2.22
SDCP	15.78
TOTAL SDG&E TERRITORY	**18**

Data is sourced from the following Commission resolutions: E-4999, E-5124, E-5246. The PCE allocation also includes 2.5 additional MW reallocated from PG&E to reflect the load migration of the city of Los Banos per PG&E advice letter 6313-E.

5) Multiply the $/MW program administration cost by 5 MW to match the project size.

<u>Retail Rate Discount Incentives</u>

The DAC-GT program offers a 20% total bill reduction to participants. Participants must be enrolled in either the CARE or FERA programs. Recent average CARE and FERA rates were sourced from joint rate comparisons from either the IOU or CCA websites. The default residential TOU rate option was selected as the basis of the calculation. These are listed in the table below.

	Default TOU Rate Option
PG&E	E-TOU C
SCE	TOU-D-4-9
SDG&E	TOU-DR-1

For CCA rates, CCAs have multiple rate products, typically one for 100% green and another one applied to all other customers.[6] CCSA used the rate that was not 100% green.

Rates are assumed to escalate at 4%/year. This is consistent with the assumption E3 used in the NEM cost effectiveness analysis in the NEM 3.0 proceeding.[7]

[3] Note, the capacity reported in the CCA rebuttal testimony in this proceeding is lower than this amount.
[4] This is lower than the 70 MW initially allocated to the PG&E service territory because the 0.01 MW initially allocated to VCEA was removed from the allocation in E-5124.
[5] As explained above, this includes the 1.31 MW allocated to CalChoice.
[6] The exception is CPA that has three rate products. CCSA used the Clean rate product which is the product DAC-GT customers are enrolled in.
[7] E3, "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020," p. 13.

The assumed breakdown between CARE and FERA participants reflects the CARE and FERA customer counts presented by E3 in the Advance Demand Flexibility proceeding.[8] Based on this data, 97% of the program load was modeled as CARE and 3% as FERA.

A weighted average for each IOU territory was developed using the same weighting factors used to weight program administration costs. The only exception is PCE, which has separate rates for Los Banos and San Mateo. The Los Banos rates were applied to 2.5 MW based on PG&E advice letter 6313-E. The rest of PCE's allocation was assumed to receive the San Mateo rate.

Total Resource Cost (TRC)

Per the standard practice manual, the total resource cost test "measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." For this analysis TRC incorporates project costs and program administration costs.

Rate Impact Measure (RIM)

The RIM includes utility costs and lost revenues due to sales reductions. Because the solar project is modeled as in front of the meter, there are no lost sales revenues included in the analysis. For this analysis RIM incorporates project costs, program administration costs, and retail rate discount incentives as a cost.

Program Administrator Cost (PAC)

Since there is no separate third-party administrator, this is a utility cost test. Per the SPM, the utility costs included in this test are the same as the RIM, except it excludes the impact of lost revenues from load reductions. Since no such load reductions have been modeled, the PAC and RIM results are identical.

Benefit-Cost Ratios

Once annual benefits and costs are quantified, they are expressed as a net present value (NPV). The NPV discount rate is equal to the IOU weighted average cost of capital in the ACC, which is 7.52%. The NPV of the benefits is divided by the NPV of the costs to calculate a benefit-to-cost ratio, also called the cost effectiveness "score." Higher scores indicate greater cost effectiveness (more benefits relative to costs).

Net Revenue Impact, Rate Impact, and Residential Bill Impact

Per the SPM, quantification of revenue impacts (net of benefits)and rate impact derive from CCSA's RIM analysis. To perform these calculations, a program size in MW or GW must be assumed. Since the ultimate program size is unknown, the results are presented on a unitized basis, either per MW or per GW as described in further detail below. Note the following methodology is essentially the same as used to model the NVBT program, except with a different program MW allocation across the three IOU service territories.

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[8] R.22-07-005, "E3 Fixed Charge Tool," (Updated April 2023), "Customer Counts" tab, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-flexibility-oir/fixed-charge-design-model-2023-04-13.xlsb; This model was developed to help entities design income-graduated fixed charges.

Net Revenue Impacts

Net Revenue Impacts are calculated on a lifecycle basis for the entire term of the analysis, either 20 or 25 years.

Lifecycle net revenue impacts are presented on an NPV basis. The NPV of the benefits calculated to do the RIM benefit-cost ratio is subtracted from the NPV of the costs. The resulting value is divided by 5 MW, the assumed project size, to provide a unitized per MW value for each IOU.

Rate Impact

Rate impacts are assessed using the lifecycle revenue impact measure described in the SPM, expressed on a per kWh basis. Rate impacts are assessed assuming a 1 GW program size with the allocation of the program MWs to the IOUs per the following table. Note this reflects the current DAC-GT allocation of 70 MW for PG&E and SCE and 18 MW for SDG&E territories grossed up to the 1 GW size. Effectively, the unitized per MW lifecycle net revenue impacts described above are multiplied by these MW values for each IOU.

	Program Size (MW)
PG&E	443
SCE	443
SDG&E	114
Total	1000

The resulting net revenue impacts are then divided by the discounted IOU annual sales. The discounting is done over the same term and using the same discount rate as used to calculate the NPV of the benefits and costs. Forecasted sales are taken from the 2022 Integrated Energy and Policy Report (IEPR) from the California Energy Commission. Values after 2035 are extrapolated at the growth rate from the final year of the (IEPR) forecast period (growth from 2034 to 2035).

Residential Bill Impact for Non-Participants

To estimate the bill impact for non-participant residential customers, the rate impact described above is multiplied by the assumed typical monthly usage for a residential customer. We assumed, for simplicity of the analysis, that the typical monthly usage is 500 kWh for each IOU.

Residential Bill Impact for Participants

Bill impacts for participants were assessed using values from the first year of the analysis period (2025) instead of the entire term. Bill credits were calculated using the same weighted average retail rate assumptions as described above to calculate retail rate incentive costs for the RIM analysis. Bill credit rates were separately calculated for CARE and FERA rates. To translate the bill credit rate to a bill impact, the bill credit rate described above is multiplied by the assumed typical monthly usage for a residential customer, i.e. 500 kWh/month.