Community Solar in California

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1. Introduction

The Golden State Solar Impact project supports the goals of the Department of Energy (DOE) Solar Energy Technologies Program and the SunShot Initiative, which seek to make solar electricity cost competitive without subsidies by the end of the decade by seeking to address and lower system costs for photovoltaics (PV). The Center for Sustainable Energy (CSE) is working as part of a statewide team to encourage market transformation through expanding financing options for residential and commercial customers, streamlining permitting processes, and standardizing net metering and interconnection standards across investor-owned and municipally owned utilities in the region. The project goals are supported by cross-jurisdictional collaboration and information sharing.

> ***Governor Brown recently issued an executive order with a target to reduce statewide emissions 40% below 1990 levels by 2030.***

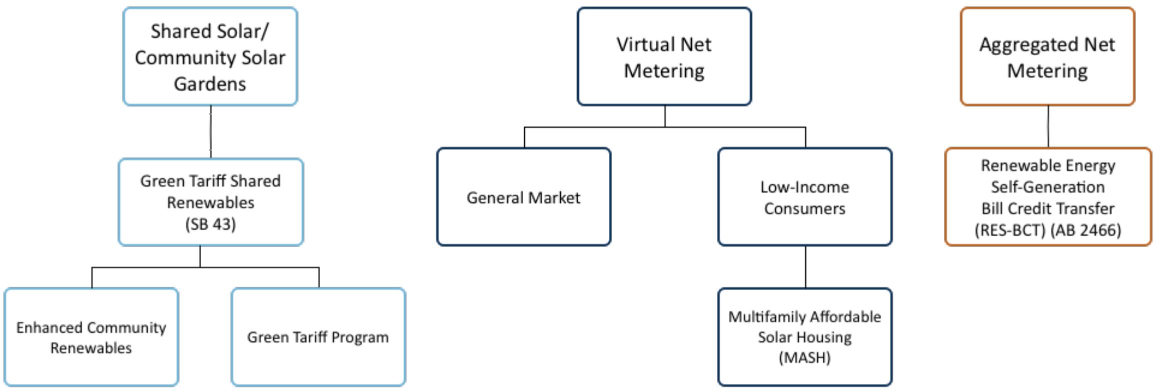
California has committed to significant greenhouse gas (GHG) emission reductions. Governor Brown recently issued an executive order with a target to reduce statewide emissions 40% below 1990 levels by 2030. To achieve these targets California has implemented a number of policies and programs to reduce emissions from the electric sector, including a Renewable Portfolio Standard, which requires energy service providers to procure 33% of their electricity sales from renewable sources, and the California Solar Initiative (CSI), which provides financial incentives toward installation of distributed solar photovoltaics systems. While the CSI program has helped to significantly expand the number of installations of rooftop solar projects around the state, many customers are unable to put rooftop solar on their properties because their property is not suitable for such a system or because they live in multitenant housing. Approximately 16.8%[1] of California's overall population lives in multitenant housing with 40% of San Francisco residents, 43% of Los Angeles residents, and 29% of San Diego residents occupying multitenant housing units.[2] Additionally, the National Renewable Energy Laboratory (NREL) estimates that nationwide approximately 49% of households (when excluding those who are renters, lack adequate rooftop space, and/or lack access to rooftop space) and 48% businesses (when excluding those businesses that operate in building that lack adequate rooftop space and/or lack access to sufficient rooftop space to meet their load) are unable to host a PV system.[3] Community solar seeks to expand access to renewable energy resources to customers who are unable to access or unable to host such systems.

1.1 Background

In recent years, several models for community solar have emerged (Figure 1). Community shared solar (or community solar gardens) allows customers across a larger geographical area (such as utility service territory) to subscribe to a solar energy system. Generally, this model works through agreement between the subscribing customer, the owner/developer of the solar system, and the utility. The subscribing customer purchases a portion of the output of the system. The system owner or operator sells the electric output to the utility—and in most cases the associated Renewable Energy Credits (RECs) —and administratively apportions this generation credit to the subscribing customer's bill in much the same way that net energy metering credits occurs. Often, the system must be located within a certain proximity to the subscriber (same municipality, county, adjacent county, or utility service territory). California recently enacted a Green Tariff Shared Renewables (GTSR) program that allows customers to participate by either directly subscribing to a percentage of renewable energy provided by their investor-owned utility (i.e., PG&E, SDG&E, or SCE) to serve their load under a Green Tariff program or to contract directly with a solar developer and their investor-owned utility to subscribe to a percentage of a solar project under a Enhanced Community Renewables (ECR) program.

Virtual net metering (VNM) describes the allocation of electricity generated from a solar system at a multi-tenant property (such as apartments and condominiums) to multiple accounts at that property. VNM uses the same premise as net metering with the major difference being the ability to credit multiple-customer accounts without requiring physical interconnection to each customer's meter. California uses VNM to allow tenants that live in multitenant units to access renewable energy generation through a billing mechanism.

Figure 1 Community Solar Categories and Related Programs in California



Aggregate net metering allows the electrical output of a renewable energy system to be allocated to multiple meters belonging to the same customer. Certain states require that the properties where the aggregated meters are located be adjacent or contiguous to the property where the renewable generation system is located. In California, aggregate net metering occurs under both California Public Utilities Code Section 2827(h)(4)(a)-(b) and the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) that allows allocation across multiple facilities and meters belonging to the same customer, such as a school district.

1.2 About this Report

This report provides an overview of community solar policies and programs in California. Section 2 discusses the shared solar programs developed as a result of Senate Bill (SB) 43,[4] including a detailed discussion of the requirements for both the ECR and Green Tariff programs. Section 3 summarizes California's virtual net metering programs, including the Multifamily Affordable Solar Housing (MASH) and Single-Family Affordable Solar Homes Programs (SASH). Section 4 addresses California's aggregate net metering program, the Renewable Energy Self-Generation Bill Credit transfer (RES-BCT) as authorized by Assembly Bill 2466.[5] Finally, Section 5 addresses Community Shared Solar models in other states.

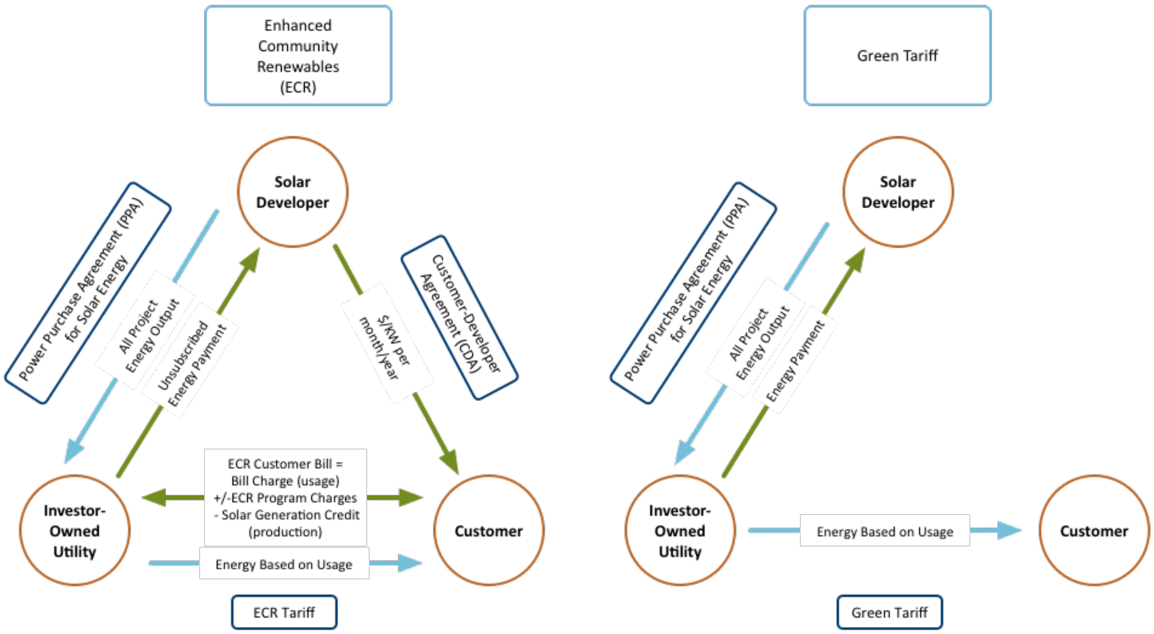
2. Shared Solar in California (SMUD SolarShares and SB 43)

Shared solar in California takes three forms presently. The Sacramento Municipal Utility District (SMUD) SolarShares program represents the first form. SMUD first introduced shared solar to California in 2008. SolarShares provides customers with the opportunity to subscribe to a share of a solar generation facility within SMUD's territory at a flat fee based on the customer's historical energy use and share size selected. More recently, SB 43 created the two other forms of shared solar in the state. The California Public Utilities Commission (CPUC) approved the state's three investor-owned utilities (IOUs) shared solar programs earlier this year.

Shared solar in California takes three forms presently.

The IOU programs take two forms. The first allows customers to subscribe to 50% to 100% of their electric load from projects procured by the utility under what is now the SB 43 Green Tariff Shared Renewables program. The second allows customers to enroll in a SB 43 Enhanced Community Renewables (ECR) program that requires the customer to execute a separate agreement with a solar developer to buy rights to a specified portion of a local solar projects output. ECR power purchase agreements are executed between the utility and the solar developer for procurement and are separate from the agreement between the customer and solar developer. Figure 2 summarizes the program structure and the relationship between parties involved.[6].

Figure 2 Comparison of SB 43 Shared Solar Program Structures



This section provides a summary of SMUD's SolarShares program, Senate Bill 43, the subsequent regulatory process, and the program attributes of both the Green Tariff Shared Renewables and Enhanced Community Renewables programs.

2.1 Shared Solar in California before SB 43

2.1.1 SMUD's SolarShares Program

SMUD's SolarShares program began in 2008, before any proposed IOU program or the enactment of SB 43. SMUD's program allows customers to subscribe to a percentage of generation output from a solar energy system owned by SMUD or a third party developer. The subscriber can purchase 0.5 kilowatt (kW) shares of the system (costing $10.75 per month).[7] The present system is 1 megawatt (MW)(1000 kW) and became fully subscribed in about six months[8] with approximately 700 customers meeting somewhere between 20-40% of their load.[9]

The customer pays a flat monthly fee that is based upon the customer's historical energy usage (including energy use & time-of-use) and the share size.[10] Customers receive a kilowatt hour (kWh) credit on their monthly bill dependent on the generation output of their subscription and the fixed energy rate that the subscribers qualify for when they join the program.[11] The program requires that subscribers maintain their subscription for at least one year or face a $100 early cancellation fee.[12]

The SMUD pricing model requires that customers pay the fixed wholesale price as well as fixed charges that include usage charges such as SMUD's System Infrastructure fixed charges.[13] SMUD in turn pays third-party developer(s)[14] – if the system is not owned by SMUD – for the wholesale value of electricity fixed under a 20-year power purchase agreement (PPA) as well as pays the customer for the renewable energy credits from the subscribed shares.[15] SMUD estimates that this model may add 2.2 to 2.6 cents to the base rate after accounting for incentives and the marginal cost of energy.[16]

SMUD developed a proprietary customer segment model to evaluate SolarShares targets based on:

- A 4,000 customer attitudinal survey;
- Premise data including home vintage, size, HVAC, appliances and energy use; and
- A program participation index.

From this program data, SMUD determined that:

- 40% of its subscribing customers earn more than $75,000 per year;
- 90% live in a single-family, owner-occupied home;
- Subscribing Customers tend to be married males;
- Customers tend to live longer in their homes and use more energy than an average SMUD customer.[17]

Going forward, SMUD plans to add an additional six MW in the short term with a potential total increase to 25 MW, although it is currently unclear if or when this procurement will occur.[18] The program will work to maintain competitiveness with price offerings close to leased rooftop solar offerings and potentially offer time dependent pricing.[19] The program is also testing a commercial offering.[20] SMUD operates the program under the following rules:

For Commercial Customers

<u>For Energy from Solar Generator/PPA</u>

- 20-year fixed price contract at the current SolarShare price
- Bill credit will be valued at generation portion of the retail electricity usage charge
- RECs will be purchased and will vary through the length of the SolarShares contract
- Facilities, demand and customer charges will apply
    - Future rate changes will affect these charges
- Enrollment will be limited to five MW

<u>For Energy from SMUD</u>

- All system infrastructure fixed charges (SIFC) (energy, demand, facilities, customer charges, etc.) will apply
    - Future rate changes will affect these charges

For Residential Customers

<u>For Energy from Solar Generator/PPA</u>

- Customer signs a one-year agreement

- Solar Share price will remain fixed or drop for the length of the contract depending on PPA prices
- RECs will be purchased and will vary through the length of the Solar Shares contract
- The customer will receive a bill credit equal to their retail electricity usage charge calculated via the VNM process
- Subscription will be limited to 100% of the customer's annual consumption[21]

<u>For Energy from SMUD</u>

- All SIFC charges will apply
    - Future rate changes will affect these charges

SMUD's program does not fall under SB 43 or CPUC regulation. SMUD's program will continue to change and develop overtime depending on demand and other market or operational factors.

2.1.2 Investor-Owned Utility Programs

None of the proposed IOU programs became operational prior to the passage of SB 43. However, it is important to examine the inception of these programs to fully understand the implementation of SB 43.

Beginning in 2012, two of the three IOUs in California (i.e., PG&E and SDG&E) filed applications to create voluntary solar access programs.[22] These programs were intended to provide customers the opportunity to purchase additional solar energy to increase the percentage of renewable energy supplied to their account. Ultimately, both applications were consolidated by motion on July 31, 2013. It is important to note that before these two applications were consolidated, PG&E reached a partial settlement with other parties to its adjudication that:

> (1) PG&E would offer bundled, incremental renewable product to customers who voluntarily choose to procure additional renewable energy as part of their bundled electricity service;
>
> (2) Participating customers would receive rate credits for avoided generation costs and pay charges to fully convert the cost of procuring the green option resources to serve their needs;
>
> (3) PG&E would rely on existing or new renewables procurement tools and mechanisms approved by the Commission;
>
> (4) PG&E would establish an advisory group;
>
> (5) PG&E would actively market the program to low-income and minority communities and customers;
>
> (6) PG&E would track revenues and costs under balancing account ratemaking standards;
>
> (7) PG&E could incorporate energy supplies from projects located within a reasonable proximity to customer enrollees; and

(8) If over-procurement occurred, the additional resources may be applied to RPS obligations or banked for future use.[23]

This settlement agreement guided the evaluation of PG&E's GTSR program in CPUC's D.15-01-051 under SB 43. With the passage of SB 43 in October 2013, the CPUC issued a scoping memo to evaluate whether PG&E's and SDG&E's applications conformed with SB 43 and ordered SCE to file its own application for a GTSR program.[24] All three IOU applications were then consolidated into a single adjudication. This process moved through two phases before the CPUC approved D.15-01-051 on January 29, 2015, as part of Phase III.[25] This adjudication remains open with many issues still to be considered or evaluated around Enhanced Community Renewable (ECR) and Environmental Justice (EJ) programs under Phase IV. The following sections will introduce and categorize both SB 43 and the CPUC proceeding.

2.2 Shared Solar in California under SB 43

Senate Bill 43 (Chapter 413, Statutes 2013) directed the CPUC to implement the GTSR program to build upon the success of the California Solar Initiative to expand customer access to "all eligible renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation."[26] The law sets a sunset date of January 1, 2019 for the GTSR program, unless extended. The GTSR applies to all "participating utility[ies]"defined as all electrical corporations with 100,000 or more customer accounts in California,[27] which includes the three large IOUs, PG&E, SCE, and SDG&E. The law mandates that participating utilities administer the GTSR program in their service territory.[28] The GTSR allows both a Green Tariff Option (Green Tariff) and ECR option to facilitate shared solar in California. SB 43 does not mandate how procurement should be divided between the Green Tariff and ECR programs.[29]

The law places a statewide cap of 600 MW of nameplate generation capacity across all three IOUs service territories.[30] The law makes specific allocations of the total 600 MW:

- 100 MW for systems of one MW or less located in identified impacted and disadvantaged communities by CAL EPA (CPUC EJ Reservations);[31]
- 100 MW reserved for residential customers;[32] and
- 20 MW reserved for City of Davis.[33]

The CPUC issued D.15-01-051 on February 2, 2015, approving the GTSR Programs for SDG&E, PG&E, and SCE. It mandated that each IOU procure projects equal to their portion of the 600 MW cap as determined by each IOU's percentage of total statewide bundled sales as mandated by California Public Utilities Code Section 2833(d).[34] The CPUC also mandated that residential participation and the EJ facilities use the same retail sales percentage.[35] The breakdown of the procurement requirement can be found in Table 1 below:

Table 1 Allocation of Capacity, in MW[36]

	Percentage of Total IOU Bundled Sales	TOTAL (MW)	EJ (MW)	Davis (MW)	Unreserved (MW)
PG&E	45.25%	272	45	20	207
SD&E	9.87%	59	10	N/A	49
SCE	44.88%	269	45	N/A	224
TOTAL	100%	600	100	20	480

The CPUC further made the following general findings under D.15-01-051 that govern the program rollout:

(1) Indifference between participating and non-participating ratepayers can be achieved through careful rate design and procurement processes;

(2) The proposed IOU GTSR Programs, as modified by this decision, satisfy the requirements of SB 43, comply with Commission decisions and other laws, and are not anticompetitive;

(3) The existing procurement mechanism for Renewable Procurement Standard should be used for GTSR Program procurement; and

(4) To ensure additional renewable facilities are built, it is necessary to set minimum advance procurement goals for 2015.[37]

The following sections will consider the various SB 43 requirements and the latest CPUC rulemaking implementing each participating IOU's GTSR program broken down by Green Tariff and ECR programs. The following sections will address the statutory and CPUC adjudication of the various components of procurement under the GTSR.

2.2.1 Procurement

SB 43 creates the following procurement requirements based on the statutory intent to both expand access to renewable energy resources for all ratepayers and create a mechanism whereby institutional customers, commercial customers, and groups of individuals can serve their load with eligible renewable energy resources.[38]

- Participating utilities use CPUC approved tools and mechanisms for meeting California Renewable Portfolio (RPS) procurement to procure additional GTSR requirements;[39]
- Limit statewide procurement to 600 MW with each participating IOU responsible for the ratio of its retail sales to total retail electrical sales;[40]
- Authorizes the CPUC to place restrictions on GTSR purchases including "restricting participation to a certain level of capacity each year;[41]

- GTSR must support the diverse procurement and goals of CPUC General Order 156 governing the Development of Programs to Increase Participation of Female and Minority Business Enterprises in Procurement of Contracts from Utilities;[42]

- Participating IOUs track and account for all revenues and costs associated with the GTSR program in a fully transparent and auditable manner.[43]

The CPUC's D.15-01-051 focuses on the following four general principles to implement SB 43 requirements. First, the GTSR program requires "additional" procurement of renewable energy facilities beyond what would be built if the GTSR program did not exist.[44] Second, the CPUC emphasized that "proximity of generators to customers should be maximized to approximate the benefits of onsite generation."[45] Third, procurement must result in ratepayer indifference (this is specifically addressed by SB 43 in the Credit, Charges, and Cost Section below).[46] Fourth, the decision seeks to maximize the use of existing procurement mechanisms and avoid creating a new procurement mechanism.[47] Additionally, D.15-01-051 addresses the need to identify renewable resources for initial procurement and the issue of over-procurement during or at the end of the program.

Procurement Mechanisms for GTSR

The GTSR program mandates that the IOUs ensure sufficient eligible capacity is available to meet GTSR customer demand up to the 600 MW cap.[48] The CPUC authorized the use of two existing procurement mechanisms: (1) the Renewable Auction Mechanism (RAM) for Green Tariff program procurement and EJ projects; and (2) the Renewable Market Adjusting Tariff (ReMAT) for ECR program procurement (See Section 2.3.2 below).[49] All projects must meet viability requirements as established by the ReMAT and RAM programs.[50] The CPUC ordered that new solicitations under these mechanisms cannot begin after January 31, 2018, unless the GTSR program is re-authorized or extended.[51]

The RAM program currently provides procurement for utility RPS programs and allows procurement for systems of 500 kW to 20 MW under the Green Tariff programs.[52] D.14-11-042 established an additional RAM 6 auction to be completed by June 30, 2015 and also is developing a new structure for auctions that eliminates minimum and maximum procurement sizes.[53] The GTSR procurement under RAM will operate independently and as an addition to each IOU's RPS program.

The ReMAT program is a CPUC instituted "feed-in tariff with a market-based pricing mechanism…that uses a standard offer contract and automatically adjusts the offered payment rate"[54] that can provide procurement for projects between 500 kW and 3 MW under the ECR program. The ReMAT pricing mechanism operates independently to determine the market price for each of the three product categories: non-peaking as available, peaking as available, and baseload.[55] The ReMAT mechanism sets the market price separately every two months for each of these three product types for each utility dependent on market demand at the previously offered rate.[56] Solar projects fall under the "peaking as available" product category.[57] GTSR projects procured through ReMAT will not count towards statutory or CPUC feed-in tariff targets for renewables.[58] The IOUs may use the current peaking bucket price as a starting price to procure capacity.[59]

The CPUC also permitted the IOUs to solicit GTSR projects through other RPS solicitations based on the RAM model beginning with 2015 RPS Procurement Plans. The CPUC left open evaluation of additional procurement mechanisms to be considered by individual application in Phase IV of the proceeding.[60]

Additionally, SB 43 contemplates all types of renewables, but D.15-01-051 only addresses solar pursuant to the IOUs' proposals.[61] The CPUC left consideration of other renewable generation types to Phase IV.[62]

Procurement of Enhanced Communities Renewables (ECR) Capacity

SB 43 mandates that [a] "participating utility shall provide support for enhanced community renewables [ECR] programs to facilitate development of eligible renewable energy resource projects located close to the source of demand."[63]

As the CPUC notes, this language does not define a specific capacity goal for ECR, the term "support," or the term "community."[64] The CPUC relies on the legislative intent of California Public Utilities Code Sections 2831 (c) and (d) that many large institutional customers (such as schools, colleges, universities, local government, etc.) are interested in the development of renewable energy generation and the ability to participate in offsite shared renewable facilities.[65]

The CPUC created a "broad strokes" structure that rewards community involvement, increased renewables, locational benefits, and certainty of renewable power costs.[66] The CPUC balances this broad strokes structure with the regulatory oversight designed to prevent customer manipulation by third party developers and/or developer manipulating of the ECR selection process through a showing of "sham" community interest.[67] As such, ECR will follow many of the same rules and structures as the Green Tariff with the main difference being that the transaction is structured between the IOU, a developer, and the customer.[68] It remains unclear exactly how the agreement between the subscribing customer and the developer will be structured in terms of payment, rights, and obligations. The CPUC also will evaluate whether RAM should be used to procure ECR projects under Phase IV for projects larger than 3 MW.[69]

Under ECR procurement, the structure first requires that the IOU and developer sign a PPA based on the form ReMAT agreement.[70] The agreement will include an ECR rider that the IOUs will develop subject to CPUC approval.[71] The rider will include customer protections and govern developer behavior.[72] The ECR PPA will use the ReMAT or RAM price with specific provisions to prevent ECR projects from losing subscribing customers over time.[73] Because the goal of the GTSR program is to have a fully subscribed customer base, the CPUC adopted the Default Load Aggregation Point (DLAP) price available from the CAISO as a proxy for market value for all unsubscribed power to incentive developers to maintain full community subscription.[74] The CPUC left room for adjustments to the Unsubscribed ECR Price and mandated that developers meet the subscription levels in table 2.[75] The subscription level will be assessed at the end of each billing cycle subject to a 5% adjustment for normal subscription changes.[76] Additionally, the CPUC set the Unsubscribed ECR Price at the lesser of either the DLAP price or the PPA contract price to prevent the DLAP price from increasing above the contract price (incentivizing developers to reduce subscription rates).[77] The Unsubscribed ECR Price only will apply to unsubscribed capacity and only during billing periods in which the project does not meet the subscription minimum.[78] The following table lists the progressive required subscription levels that must be met by each ECR project during the first three years of operation.

Table 2 Customer Subscription Minimums for ECR Projects

Years of Operation	Required Customer Subscription Minimum Percentages
First Year	50%
Second Year	75%
Third Year	95%

As previously noted, all unsubscribed energy purchased by the IOU will be applied to the RPS procurement or banked. The CPUC ordered that the IOU should pay for both the Unsubscribed ECR Price and the market value of the associated RECs for all unsubscribed ECR energy transferred at the Unsubscribed ECR Price to ensure this energy meets RPS program requirements.[79] The CPUC determined that this amount should never exceed the PPA price and the CPUC left the determination of the market value for RECs to Phase IV.[80]

Second, the structure requires that customers and developers sign a customer developer agreement (CDA) under which the developer and customer are free to design their own transaction structure to meet both parties' goals and ensure that the project is financeable.[81] This agreement must protect customers and "provide representations, warranties, and indemnifications sufficient to project the IOU and its shareholders in the event of a dispute between the developer and the customer."[82] This structure allows the sale of a percentage of a facility's capacity or a set price per kWh of energy assigned to the customer amongst other possibilities.[83] Importantly, the developer will assign all rights to payment under the PPA to the customer preventing direct sales of energy by the developer to the customer to avoid conflicts with existing direct access rules.[84] It remains unclear what form these agreements will take as well as the actual cost to the customer. More information will become available once the first project or sets of projects are developed.

Third, the structure requires customers to sign up for an ECR tariff with the applicable IOU with the developer supplying the IOU with requisite information on price and the amount of credit to apply to the customer's bill.[85] The charge and credit are derived from the amount of energy generated and the portion of that generation subscribed to by a customer.[86] The ECR rate structure mirrors the Green Tariff structure except that the ECR is specific to a facility and does not include payment from the customer to the developer.[87] Specifically, the customer "will receive a credit from the IOU for the class average generation rated on a volumetric basis equal to the customer's assigned share of facility output" because the developer has assigned its rights to payment to the customer.[88] The customer will be billed for actual usage on a volumetric basis at the facility price and will receive a credit from the

IOU.[89] Customers will also receive an avoided cost of generation credit based on average generation rate.[90]

This structure requires that each project meet a "sufficient demonstration of community interest" demonstrating that it meets the goals of the ECR program.[91] The CPUC adopted the definition of "community" as "customers within the same municipality or county, or within ten miles of the customer's address."[92] Additionally, the CPUC determined that community interest will be evaluated by: "(a) documentation that community members have committed to enroll in 30% of the project's capacity or documentation that community members have provided expressions of interest in the projects sufficient to reach 51% subscription rates; and (b) a minimum of three separate subscribers to reflect the "shared" aspect of the program."[93] The CPUC also determined that at least one ECR project must have a residential subscription of at least 50%.[94] Additionally, all projects that demonstrate community interest are subject to evaluations for meeting overall GTSR portfolio requirements, such as residential and EJ.[95]

The CPUC also adopted the following program design for the structure:

- Once an ECR project is developed, subscribers can come from anywhere within the IOU's territory (making the subscription portable within the IOU territory).[96]
- 120% of annual load will be used to determine a customer's subscription for the maximum of 100% of their energy demand.[97]
- Subscriptions with the developer may extend for any length of time and a customer's ECR participation should terminate automatically when the PPA terminates.[98]
- ECR customer can retain their subscription at their new address when he or she moves as a result of the subscription being portable within the IOU's territory.[99]

The CPUC further required that the developer of each ECR project include a securities opinion from an AmLaw 100 law firm "stating that the arrangement complies with securities law, and that the IOU and its ratepayers are not at risk for securities claims associated with the project."[100] Further refinements to this requirement will be evaluated under Phase IV.

Finally, the CPUC left open further proposed changes to the ECR transaction structure for Phase IV.[101]

2.2.2 System Size

SB 43 mandates the following system size and limits:

- Nameplate rated generating capacity shall not exceed 20 MW for all areas not identified as impacted and disadvantaged communities by the California EPA;[102]
- Nameplate rated generation capacity shall not exceed one (1) MW for systems located in identified impacted and disadvantaged communities by the California EPA;[103]

The CPUC ordered that the IOUs accept Green Tariff projects ranging from 500 kW to 20 MW and ECR projects ranging from 500 kW to 3 MW. Environmental Justice projects must range between 500 kW and one MW, with the CPUC to address making the system minimum smaller for these types of projects in Phase IV.[104] The CPUC set the 500 kW minimum to ensure that a facility can operate in the CAISO market with its own generator resource identification as well as to ensure a certain scale to decrease the amount of administrative time and resource in managing the programs.[105]

2.2.3 Initial Advanced Procurement, Continuing Procurement, and Program Termination

CPUC D.15-05-051 addressed initial and continual procurement by mandating minimum advanced procurement (Table 3) with contract for such procurement completed within one year of the decision matched to enrolled subscribers to the extent possible.[106] The CPUC mandated procurement under existing ReMAT and RAM 6 to take advantage of the expiring federal investor tax credit (ITC) prior to customer enrollment with IOUs filing an Advice or Procurement Letter for compliance.[107] These letters will include detail on progress towards the 600 MW cap and include proposals for prioritizing ECR and EJ qualifying projects.[108]

The CPUC set a minimum advance procurement target of 18% for all IOUs with a maximum authorized procurement of 33% for SCE and PG&E and 42% for SDG&E.[109, 110] The CPUC mandates that each IOU seek to enroll subscribing customers equal to the minimum capacity requirements below.[111] The advanced targets can be seen in Table 3.

Table 3 Advanced Procurement and On-Going Targets[112]

	Minimum Advanced (MW)	Authorized Max (MW)	EJ Target Authorized (MW)	EJ Max (MW)	Davis Authorized (MW)	Total (MW)
PG&E	50	68	8.3	11.3	20	272
SDG&E	10.5	25	1.75	4.2	N/A	59
SCE	50	67	8.3	11.3	N/A	269
Total	110.5	160	18.35	26.8	20	600

The CPUC further required that each IOU detail its progress towards its part of the 600 MW total GTSR in its annual RPS Procurement Plan filing and set January 31, 2018 as the last day for procurement solicitation unless the GTSR program is extended.[113]

Interim GTSR Renewable Resource Pool

The CPUC created an interim GTSR resource pool to supply subscribing customers with electricity during the transition to projects procured specifically for the GTSR program.[114] The interim GTSR Pool allows the IOUs to draw on existing RPS resources that are GTSR eligible in the short-term with all future procurements adding “additional” GTSR eligible facilities through the proscribed procurement mechanisms.[115] However, the interim GTSR Pool will not count towards the GTSR cap of 600 MW as these projects will be returned to the RPS programs once GTSR resources are brought online.[116] The GTSR Pool will be sourced from projects that came online in 2013-2014 or that are expected to come online at the end of 2014.[117] A cost-sharing mechanism will be employed to allocate costs to GTSR customers and the GTSR Pool will be removed from each IOU RPS program during this interim period. The CPUC ordered each IOU to provide a list of exiting, qualifying RPS projects that are between 500 kW and 20 MW in the IOU's service territory that went online during or after 2013.[118] These submittals will include price and cost information for the CPUC's Energy Division to evaluate whether these projects are reasonable and not high or low priced projects.[119]

Early Termination and Program Sunset

SB 43 does not contemplate early termination. However, the CPUC determined that the IOUs may suspend their programs to protect ratepayers and must submit their proposal for resolving the issue in an Advice Letter to the CPUC.[120]

SB 43 sets a sunset date of January 1, 2019, for the GTSR program. The CPUC determined that the IOUs must use an Advice Letter to make changes to their GTSR program that would extend the program for new customers beyond January 1, 2019, or terminate the program.[121] Participating customers may continue on a month-by-month basis with no additional customers able to join if an IOU's GTSR program is not extended past this date.[122]

2.2.4 Resource Proximity to Subscribing Customer

As mentioned above, one goal of community solar programs is to enable the distributed rooftop solar experience for customers who cannot install systems on their premises. As such, SB 43 mandated that "[t]o the extent necessary…" the procurement of distributed resource be within "…reasonable proximity to enrolled participants".[123]

The CPUC adopted PG&E's proposal for all IOUs. PG&E proposed "to track customer enrollments in the various communities it serves according to percentages of customer and usage. PG&E will communicate in advance to the communities that are furthest along and will preferentially procure power from 'appropriately priced, viable projects' that are located in or adjacent to these communities."[124] The CPUC further stated that the IOUs should develop innovative mechanisms to further engage communities in their service territory including making information readily available online.[125]

Specific to the ECR program, the CPUC found that a "sufficient demonstration of community interest" demonstrating that each project meets the goals of the ECR program must occur.[126] The CPUC adopted the definition of "community" as "customers within the same municipality or county, or within ten miles of the customer's address."[127] This suggests that these systems will most likely be located within communities where sufficient community interest exists. However, subscribers can come from anywhere within the IOU's territory once these projects are operational (making the subscription portable within the IOU territory).[128] Further discussion of this structure can be found in Section 2.3.2 above.

At a minimum, the GTSR projects must be located within the service area of the procuring IOU (with the exception of SDG&E procuring RAM projects in the Imperial Valley that are dynamically scheduled by the CAISO per the existing RAM program).[129] Because ReMAT and RAM procurement programs lack location specific criteria required by SB 43, the CPUC left open how to meet SB 43 requirements under these procurement mechanisms for Phase IV.

Environmental Justice (EJ) Reservation Procurement for EJ Projects

SB 43 mandates that 100 MW of the GTSR program be reserved for generator facilities one MW or less located in the "the most impacted and disadvantaged communities" pursuant to the CalEPA.[130] EJ Projects must be located within the 20% most impacted areas based on the best available screening methodology that identifies: "(i) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation. (ii) Areas with socioeconomic vulnerability."[131] The CPUC determined that the best available screening methodology is the CalEnviroScreen.[132] The CPUC ordered the IOUs to work with the current CalEnviroScreen data to identify the most impacted 20% of communities (current CAlEnviroScreen 2.0 identifies the most 25% impacted).[133] The CPUC determined that the 20% most impacted communities shall be determined on a service territory basis rather than a statewide basis.[134] The CPUC further found procurement through RAM and ReMAT for EJ projects reasonable.[135] The CPUC also determined 500 kW as the reasonable minimum project size for EJ Projects with further evaluation to occur under Phase IV.[136] Additional considerations for Phase IV include:

- Allowing projects sized under 500 kW;
- Preferential treatment for EJ Projects in RAM and ReMAT solicitation;
- Developing alternative pricing for EJ Projects;
- Collaboration with community based organizations in identified EJ areas; and
- Refinement of methodology for identifying EJ Reservation locations.[137]

2.2.5 Over Procurement and Customer Attrition: RPS Backstop

The CPUC and many stakeholders expressed concerns about over-procurement caused by customer attrition or other causes.[138] The CPUC determined that use of the RPS program as a backstop for over-procurement pursuant to California Public Utilities Code Section 2833(s) results in a reasonable and efficient resolution that would not cause unjust or unreasonable rates for ratepayers.[139] In other words, if an IOU procures a GTSR project but lacks adequate customer subscription for that system during the program or because the program has terminated, the system may be transferred to the IOU's RPS program as a backstop. This approach avoids having stranded projects during or at the end of the program. The CPUC acknowledged that there is no "reasonable, practicable, definitive method for determining price difference" between GTSR procured projects and RPS projects. The CPUC required tracking and reporting of GTSR generation that is applied to the RPS or banked to ensure that these transfers do not impact the RPS program's cost to ratepayers. The CPUC seeks to ensure that unreasonable costs are not shifted to non-participating ratepayers to ensure ratepayer indifference.[140]

2.2.6 Community Advisor

D.15-01-051 focuses on the need for community and customer level involvement to advise the IOUs in development of the GTSR Program.[141] The IOUs proposed two different models for community advisement. PG&E proposed an advisory group, while SDG&E and SCE proposed utilizing a network of community groups and stakeholders (advising network) for input and outreach.[142] The CPUC approved both approaches and ordered immediate meetings with these groups by each IOU to avoid GTSR implementation delays.[143] The groups must include interested government institutions and community choice aggregators (CCAs).[144] The CPUC expects these groups to be a source of reporting aggressive or misleading sales tactics for ECR customer subscription.[145] Additionally, the CPUC made it clear that these are advisory groups with no decision making authority and specified that the IOUs must respond to their input and give it a role in marketing the GTSR Program.[146] The CPUC also requires annual reporting on the frequency of meetings, topics discussed, and other relevant information.[147]

2.2.7 Customer Subscription

With respect to customer subscription, SB 43 mandates the following:

- Prevents customer(s) from subscribing to more than 100% of their demand or load;[148]
- Prevents customer(s) from subscribing to more than two MW of nameplate generating capacity (except for federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California);[149]
- Prevents any single entity or its affiliates or subsidiaries from subscribing to more than 20% of any single calendar year's total cumulative rated generating capacity;[150]

The CPUC's D.15-01-051 ordered that the GTSR Program should offer a variety of participation levels to ensure customer participation at all income levels.[151] The CPUC directed a minimum of 50% subscription level with the maximum being 100% per SB 43.[152] All three IOUs were ordered to offer enrollment from 50% to 100% with further evaluation of what incremental subscription levels will work best based on advisory group and/or customer feedback.[153]

The CPUC also ordered the IOUs to set an initial contract term of up to one year and authorized early termination fees as approved by the CPUC.[154] All three IOUs were ordered to offer a 60-day cooling off period to protect customers from bill increases.[155] New customers would be able to cancel or change their subscription after seeing their bill during the 60-day period.

2.2.8 Credit, Charges, and Cost

Related to credit, charges, and costs related to community shares solar, SB 43 mandates that:

- The CPUC set all GTSR program charges and credits in a "manner that ensures nonparticipating ratepayer indifference for the remaining bundled service, direct access, and community choice aggregation customers and ensures that no costs are shifted from participating customers to nonparticipating ratepayers";[156]
- The CPUC issue bill credits for generation using the average retail generation cost and renewable adjustment value adder ("the difference between time-of-delivery profile of the eligible renewable energy resource used to serve the participating customer and the class average time-of-delivery profile and the resource adequacy value, if any");[157]

- The CPUC charge customers a renewable generation rate established by the CPUC that includes administrative cost and any other charges determined to be just and reasonable to cover the costs of the GTSR program;[158]

- The CPUC issue debits or credits based on a participation customer's rates with any other applicable CPUC approved costs or values;[159] and

- Participating customers pay all other applicable charges without modifications.[160]

D.15-01-051 orders that existing price-setting mechanisms of ReMAT and RAM be used for GTSR procurement subject to a "reasonableness" standard to determine the cost-effectiveness of a bid.[161] Phase IV will examine proposals to prioritize GTSR procurement under RAM and ReMAT, which may increase bid pricing for qualified projects.[162]

The IOUs proposed applying various charges for cost recovery under the GTSR rate design.[163] The CPUC determined that charges for rate design will "float" to accommodate changes in costs from year to year and customers will continue to pay tariff distribution charges and non-bypassable charges.[164] The commodity rate for the GTSR - the Renewable Power Rate (RPR) - will initially be based on the weighted average cost of the power from the Interim GTSR Pool (Estimates: PG&E: $107 per MWh; SDG&E: $89 per MWh; SCE: $108.9 MWh). Green Tariff customers will pay a RPR charge based on the incremental cost of new projects once these projects become commercially operational.[165] This may be averaged with the Interim GTSR Pool if necessary.[166] RPR for ECR customers will be tied to the specific generation facilities.[167]

To ensure ratepayer indifference, GTSR customers will pay Power Charge Indifference Adjustments (PCIA) and are directed to include and explain how Competitive Transition Charges (CTC) are calculated and applied.[168] The indifferent charges will be updated in each IOU's annual ERRA forecast proceeding when a new PCIA is set.[169] The CPUC directed the IOUs to use vintage PCIA as a proxy for indifferent adjustment making GTSR customer indifference adjustment "vintage" by the year the customer enrolled.[170]

The CPUC approved the additional following charges:

- CAISO and WREGIS costs subject to the IOUs providing additional information on what costs the IOUs intend to include;[171]

- Resource Adequacy (RA) adder from the annual PCIA (this will include the positive value associated with GTSR facilities);[172]

- Marketing and overhead costs based on volumetric basis[173](that include a shareholder backstop subject to reasonableness review[174]) that are subject to future determinations in Phase IV (ECR marketing costs will be tracked separately from Green Tariff charges[175]);[176]

- Renewable integration charges that were approved at zero until they can be calculated and added to the costs for incremental GTSR projects.[177]

The CPUC also approved the following credits:

- Generation Credit for the cost of avoided generation
  - SCE & PG&E: credit subscribers at the Class Average Retail Generation Rate for the customer class of the participating customer;[178]
  - SDG&E: Credit based on the adjusted class average commodity costs but will substitute the ERRA component of the average commodity rate by customer class to better approximate cost;[179]
- Solar Value Adjustment (SVA) that include the time-of-delivery (TOD) value and RA value for the solar production;[180]
- Locational Grid Benefits (dependent on future proposed IOU methodology).[181]

2.2.9 Renewable Energy Credits /RPS Interaction

As described above, the shared solar programs interact with the RPS. SB 43 mandated the following related to RPS and renewable energy credits (RECs):

- Retirement of RECs procured by the participating utility and used by participating customer (such credits cannot be further sold, transferred, or further monetized for any purpose); any procured but unused RECs shall count toward participating utility's RPS;[182]
- That all renewable energy procured for the GTSR comply with the California Air Resources Board's Voluntary Renewable Electricity Program and states that California-eligible GHG allowances associated with purchases of GTSR renewable energy shall be retired on behalf of the participating customer under the Voluntary Renewable Electricity Program;[183]
- That participating utilities apply any excess generation from the GTSR caused by customer attrition or other causes that reduce participation or electric demand below generation levels to RPS requirements or to bank excess generation under RPS banking and procurement rules;[184] and
- That participating utilities exclude total retail sales in kWhrs generated from GTSR renewable generation once such facilities become commercially operational from calculations for RPS procurement.[185]

The CPUC reiterated that all three IOUs must retire all of the RECs associated with the energy procured on behalf of GTSR customers.[186] This ensures both that RECs associated with energy consumed by GTSR customers is not counted for RPS compliance and that any GTSR over procurement can be applied for RPS compliance by an IOU that retires the REC, if necessary.[187] The CPUC ordered each IOU to set up a Western Renewable Energy Information System (WREGIS) sub-account to retire GTSR RECs on an annual basis.[188] Importantly, RECs associated with the Interim GTSR Pool do not count towards the GTSR 600 MW cap for new capacity and will be tracked under separate WREGIS sub-accounts.

2.2.10 Marketing to Non Low-Income, Low-Income, and Minority Customers

The GTSR program must successfully attract customers to the programs.[189] SB 43 further mandated that participating utilities market the GTSR to low-income and minority communities and customers to the extent possible.[190]

Affordability remains an open question. The CPUC must ensure that the GTSR is both affordable to low-income participating customers without affecting affordability for non-participating customers.[191] Currently, only a varied subscription level was proposed to address this mandate but other mechanisms will be evaluated under Phase IV.[192]

The CPUC approved the IOUs' general marketing plans including the use of bill inserts.[193] However, it remains unclear how the IOUs will market to low-income and minority communities and customers. The CPUC also ordered that each IOU include a description of how it will avoid selective marketing in areas where a CCA exists, or where a CCA implementation plan has been adopted by a local authority, in its marketing plan in addition to providing specific information mandated by the CPUC.[194] For ECR programs, the CPUC mandated that the IOUs review the marketing materials and information submitted to them by GTSR program bidders.[195]

2.2.11 Reporting, Information Sharing, and Data Sharing with Local Government

The CPUC determined that reporting and information sharing were essential elements to the success of the GTRS Program. The CPUC ordered specific deliverables on both monthly and annual bases that contain explicit content.[196] SB 43 further requires participating utilities to provide aggregated consumption data to municipality for participating customers located in the municipality's jurisdiction for climate action goal reporting and public disclosure, on a geographical basis, and consumption data and reductions in emissions of GHG by participating customers in the GTSR program in an aggregated basis consistent with privacy requirements.[197]

This mandate is part of the annual reporting content requirement.[198]

2.2.12 Interaction with Community Choice Aggregators and Direct Access Customers

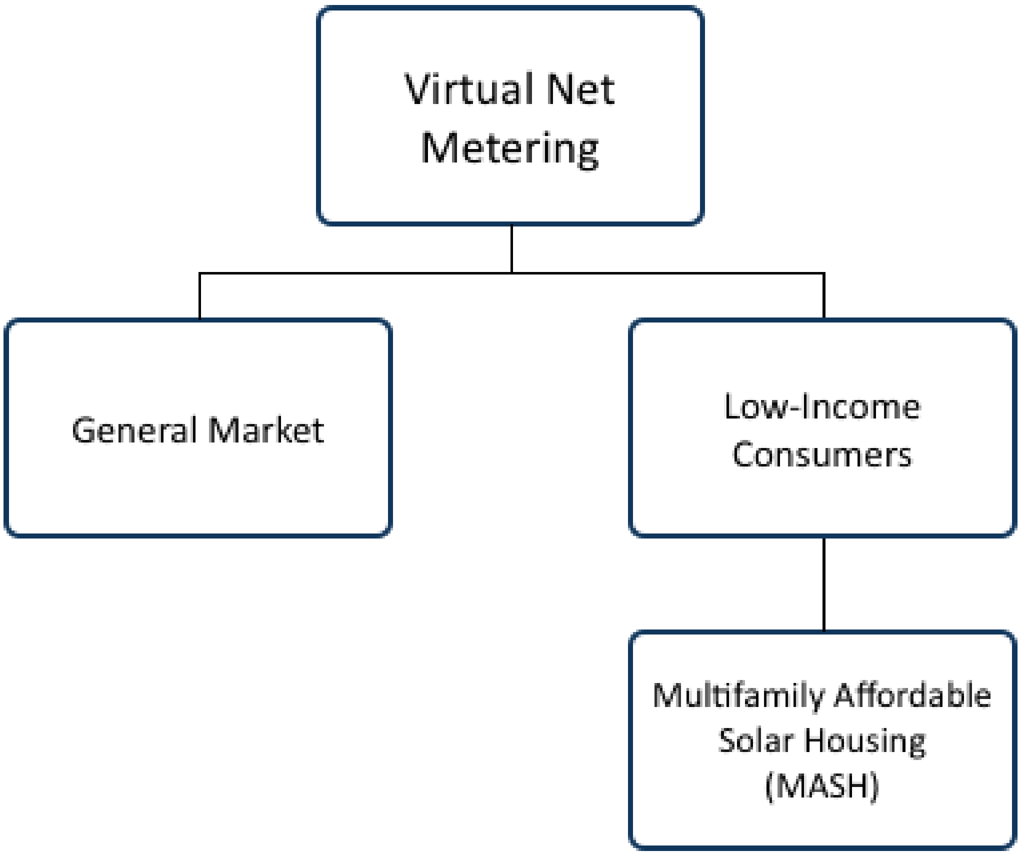
SB 43 mandated that the CPUC ensure that community choice aggregators (CCAs) are not prohibited or restricted from providing their own voluntary renewable energy programs.[199]

The CPUC concerns center around IOU anticompetitive behavior in CCA territory.[200] Because none of the IOUs filed a valid Code of Conduct compliance plan for selective marketing in CCA territory, the CPUC determined that the IOUs are precluded from such selective marketing.[201] The CPUC further directed the IOUs to submit GTSR marketing materials in any CCA Code of Conduct plan filed in the future and mandated that the Public Advisor's Office (PAO) review and approve the wording in any of these types of marketing materials.[202]

3. Virtual Net Metering

The following sections will address how virtual net metering (VNM) operates in California. This includes a detailed discussion of both the Multifamily Affordable Solar Housing (MASH) program. The Single-Family Affordable Solar Homes (SASH) program does not allow VNM but is discussed to provide additional information on the history of MASH funding and related program formation by the CPUC. Figure 3 summarizes the different types of virtual net metering available.

Figure 1 Virtual Net Metering Programs in California



3.1 Virtual Net Metering Overview

VNM operates by allowing electricity generated from a single renewable energy system at a multitenant property to be allocated across multiple utility accounts at that property.[203] More specifically, VNM allows participants to install a single solar system to cover the electricity load of both common and tenant areas connected at the same service delivery point (SDP). The electricity generated by the solar PV system flows directly back onto the grid. The participating utility then allocates the kilowatt-hours to both the building owner's and tenants' individual utility accounts, based on a pre-arranged allocation agreement. VNM was piloted under the MASH program beginning in 2009 to help low income multifamily residents receive direct benefits of the building's solar system, rather than allowing all of the benefits to go to the building owner.

The CPUC made certain changes to the MASH program in 2011 as well as expanded VNM to the general multitenant market. The CPUC expanded MASH program participation beyond customer accounts served by the same SDP as the renewable energy system. This allowed VNM allocations to "all of the real property and apparatus employed in a single low-income housing enterprise on contiguous parcels of land" even if divided by a public thoroughfare.[204] The CPUC expanded VNM to also include the general multitenant market under D.11-07-031. However, the CPUC limited non-MASH projects to a single SDP, restricting the general multitenant market in the same way that MASH was originally restricted. Removal of this limitation may make VNM more accessible to general multitenant market.

VNM projects are limited to a maximum system size of one MW and require a separate meter to track generation export to the grid. There must be at least two benefiting accounts to establish VNM, which may include both tenant and common areas. A non-MASH VNM applicant will submit a list of benefiting accounts and percentages of total output to be applied to each account and make changes to the allocation. MASH customers must make an initial allocation between tenant and common area allocations, which cannot be changed for the first five years of the agreement. Operable interconnection agreements also require MASH allocations to be proportional to the relative size of each unit.

3.2 Multifamily Affordable Solar Housing (MASH) and Single-Family Affordable Solar Homes (SASH) Programs

Senate Bill 1 (Chapter 132, Statutes 2006,) created a collaboration between the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) to establish the California Solar Initiative (CSI) overseen by the CPUC and the New Solar Homes Partnership (NSHP) overseen by the Energy Commission. These programs committed $2.5 billion of ratepayer funds over 10 years to provide rebates for the installation of qualified solar energy systems, including a requirement that 10% of funding be used for low-income residential customers and affordable housing projects across the three IOUs' service territories.[205] The CPUC opened rulemaking R.06-03-004 in March 2006 to implement the CSI program, including the low-income and affordable housing incentive programs. The CPUC adopted D.06-08-028 in August 2006, specifying implementation details for the CSI and scheduling low-income and affordable housing implementation within Phase II of the rulemaking. The Governor signed SB 1 into law, also in August 2006, providing a modified budget and other directives for both the CSI and NSHP. In response, the CPUC issued D.06-12-033 in December 2006, adopting a 10-year general market CSI budget of approximately $2.17 billion and a low-income incentive budget of approximately $216.7 million.[206] AB 2723 (Chapter 864, Statutes 2006) was also signed into law during this time, mandating that not less than 10% of overall CSI funds be used for installing solar energy systems on "low-income residential housing," as defined.

The CPUC adopted D.07-11-045 in November 2007, establishing the $108 million Single-Family Affordable Solar Homes (SASH) program, and D.08-10-036 in October 2008, establishing the $108 million Multifamily Affordable Solar Housing (MASH) program.[207] In 2013, AB 217 (Chapter 609, Statutes 2013) authorized an additional $108 million in new funding for MASH and SASH, set a goal of 50 MW of installed capacity across both programs (which, in turn, D.15-01-027 determined the split to be 37.5 MW for MASH and 12.5 MW for SASH[208]), and extended the programs until 2021 (or until the funding is exhausted).[209] The CPUC issued D.15-01-027 on January 29, 2015, to implement AB 217.[210] D.15-01-027 made certain specific changes to the MASH and SASH programs, but, unless specifically addressed, retained the same policies and procedures previously established by the CSI program that applied to the existing MASH and SASH programs.[211]

CPUC D.15-01-027 split the total of $108 million evenly between the SASH and MASH programs, continuing administration of the MASH program by PG&E, SCE, and Center for Sustainable Energy (on behalf of SDG&E) and administration of the SASH program by GRID Alternatives.[212] The Decision reduced the MASH administrative budget and ordered the rollover of administrative surplus budgets to increase and fund the incentive budget.[213] The CPUC reduced overall incentive levels for MASH and SASH and created for MASH a Track 1C and 1D incentive structure with a higher incentive for portions of a solar photovoltaic (PV) system that use virtual net energy metering (VNM) to assign generation to tenants and guarantee a structured direct economic benefit of 50% of total generation allocated to tenants (Table 3).[214] The Decision set a $3 per watt non-declining incentive structure for SASH.[215] The Decision further required Energy Savings Assistance Program (ESAP) referral or enrollment for eligible tenants, energy efficiency walk-throughs to encourage cost-effective energy efficiency before installing more expensive solar PV, and provisions for job training and employment opportunities on all solar PV systems installed under these programs.[216]

The new MASH incentive track adopted by the CPUC can be found below:[217]

Table 3 Adopted MASH Incentive Tracks

Track	Incentive Amount	Eligibility Requirements
1C: PV System Offsetting Common Area Load, Non-VNM Tenant Load, or VNM Tenant Load with <50% Tenant Benefit	$1.10 / watt	• Provide job training opportunity to more than one trainee, with one additional trainee for each 10 kW up to 50 kW • Conduct onsite walkthrough energy audit at ASHRAE Level I or higher, or enroll in a utility, REN, CCA or federally provided whole-building multifamily energy efficiency program • Portion of system allocated to offsetting one of the following: -Common Area Load -Non-VNM Tenant Load -VNM Tenant Load where tenant

		receives less than 50% of economic benefit of allocated generation
1D: PV System Offsetting VNM Tenant Load with ≥50% Tenant Benefit	\$1.80 / watt	• Provide job training opportunity to more than one trainee, with one additional trainee for each 10 kW up to 50 kW • Conduct onsite walkthrough energy audit at ASHRAE Level I or higher, or enroll in a utility, REN, CCA or federally provided whole-building multifamily energy efficiency program • Portion of system allocated to offsetting one of the following: -VNM Tenant Load where tenant receives less than 50% of economic benefit of allocated generation

Additionally, the June 2014 MASH Program Report provided the following information on projects and funding:

- 20.5 MW of solar PV capacity interconnected across 323 projects statewide
- 58 MASH Track 1 projects currently reserved with capacity of more than 7.95 MW
- Over \$73 Million paid to complete projects with additional \$19 million reserved for pending projects
- Over 6,371 tenant units participating under VNM rules.[218]

The MASH program currently has an ample waitlist of customers seeking to participate, with the last waitlist having closed on April 10, 2014. The waitlist currently has projects totaling 50 MW of solar PV capacity that will use the funding established by California Public Utilities Code Section 2851(f) and CPUC D.15-01-027.

4. Aggregate Net Energy Metering: Public Utilities Code Section 2827 and Renewable Energy Self-Generation Bill Credit Transfer Program (RES-BCT)

Aggregated net energy metering in California is allowed under both California Public Utilities Code Section 2827(h)(4)(a)-(b) and the RES-BCT program. California Public Utilities Code Section

2827(h)(4)(a)-(b) allows eligible customer-generators to aggregate electrical load across multiple meters for net energy metering purposes on property where an electrical generation facility is located and on all property adjacent or contiguous to the property where the electric generation facility is located if such properties are solely owned, leased, or rented by the eligible customer-generator. However, aggregation makes the customer-generator ineligible to received net surplus compensation for generation exported to the grid in excess of the aggregated load.[219] This means that the applicable electric utility retains any kilowatt-hours in excess of the customer's aggregated electrical load generated during the 12-month period.[220]

RES-BCT allows local governments[221] to generate electricity at one account and transfer any available bill credit to one or several "benefiting account(s)" owned by the same local government. The following sections explain the RES-BCT program in more detail.

4.1 Overview of RES-BCT

The Renewable Energy Self-Generation Bill Credit Transfer Program (RES-BCT) tariff, as enacted by AB 2466 (Chapter 540, Statutes 2008) and last amended by SB 1171 (Chapter 162, Statutes 2012), was approved by the CPUC in compliance with California Public Utilities Code Section 2830. These tariffs allow local governments[222] to generate electricity at one account and transfer any available bill credit to one or several "benefiting account(s)" owned by the same local government (See Resolution E-4283). These benefiting accounts receive service under a time-of-use rate schedule to determine payment by subtracting the generation costs from the time-of-use credit determined by when the electricity is exported to the grid from the electrical output of the eligible renewable generating facility.[223] All transactions and energy transfers are between the local government and the IOU. Each account is still subject to all costs associated with the account (e.g., interconnection, bill transfer costs, etc.) to ensure that costs are not shifted to non-participating ratepayers.[224]

4.2 RES-BCT Customer Eligibility

Under AB 2466, local governments that are eligible to take advantage of the crediting procedure provided for in the law include a city, county, whether general law or chartered, city and county, special district, school district, political subdivision, or other local public agency.[225] The legislature amended the law to include individual community college campuses, individual California State University campuses, or individual University of California campuses.[226] The state of California, any agency or department of the state of California other than an individual campus of the University of California or California State University, or joint powers authority is not eligible.[227]

Furthermore, to be eligible, a local government must satisfy all of the following criteria:

- The local government designates one or more benefiting accounts to receive a bill credit.
- A benefiting account receives service under a time-of-use rate schedule (such as AL-TOU).
- The benefiting account is the responsibility of, and serves property that is owned, operated, or on property controlled by the same local government that owns, operates, or controls the eligible renewable generating facility.

- The electrical output of the eligible renewable generating facility is metered for time-of-use to allow calculation of the bill credit based upon when the electricity is exported to the grid.
- All costs associated with the metering requirements of the bill are the responsibility of the local government.
- All costs associated with interconnection are the responsibility of the local government.
- The local government does not sell electricity exported to the electrical grid to a third party.[228]

4.3 RES-BCT Renewable Energy Generation Technologies Eligibility

To be eligible under AB 2466, each renewable generation facility must meet the following criteria:

- Have a generation capacity of no more than five MW for each individual Generating Account.[229]
- Be owned, operated, or on property controlled by the local government entity or campus.[230]
- Be located within the boundaries of the governmental entity or on land owned or controlled by governmental entity, including leased land. For a campus, be located within the boundaries of the city or city and county – if located in an incorporated area – or county if located in an unincorporated area.[231]
- Sized to offset all or a portion of electrical load of the benefiting account.[232]
- Be an eligible renewable energy resource pursuant to the California Renewables Portfolio Standard Program (Public Utilities Code Section 399.11 et seq.).[233]

4.4 RES-BCT Credit and Distributed to Other Accounts

Local governments with eligible renewable energy generation facilities that generate more electricity than can be used by the associated (or generating) account would elect a “benefiting account” or multiple benefiting accounts to which excess electricity would be credited.[234] To receive credit, an account must be located within the geographical boundaries of the local government or the geographical boundaries of the city, county, or city and county in which the campus is located and be mutually agreed upon by the local government and the electrical utility.[235]

4.5 RES-BCT Calculation of Credits

California Public Utilities Code Section 2830 requires that all accounts utilize time-of-use rates but does not require that generating and benefitting accounts be on the same rate.[236] This means that a benefitting account may utilize different rate treatments with potentially higher or lower commodity values for crediting than that of the generating account.

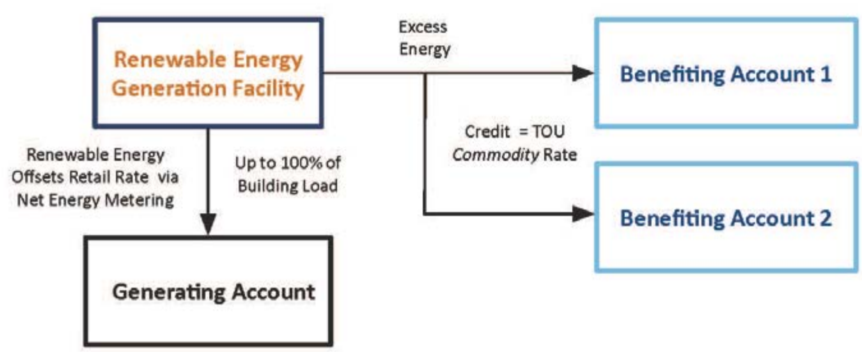
Under the program, a credit would be created when a renewable energy generation facility associated with an electrical account (“generating account”) produced more electricity in a given billing cycle than was consumed by that account. Because “eligible renewable generating systems will be installed on the host customer’s side of the utility meter, the host-site account will offset any demand that is coincident with generation behind the meter. Such generation will effectively be valued at the full retail rate that the customer would have otherwise paid the utility for the same electricity.”[237] The total amount consumed by the generating account would be measured by net energy metering. The credit under AB 2466 would be equal to the amount of excess electricity produced in a billing cycle multiplied by the commodity rate of the applicable time-of-use tariff for the benefiting account.[238] The credit would not include the transmission, distribution, and ancillary charge components that together with the generation components comprise full retail rates.[239] For illustrative purposes, examples of current time-of-use commodity prices for the three IOUs, which are available for commercial entities (including governments), are presented in Table 4.

Table 4 Examples of Generator Commodity Values for TOU Tariffs under RES-BCT ($/kWh)

Utility	Tariff	Time of Year	On-Peak	Semi-Peak	Off-Peak
PG&E[240]	Schedule E-20	Summer	0.13165	0.08668	0.05704
		Winter	N/A	0.08029	0.05824
SCE[241]	Schedule TOU-GS-1	Summer	0.16516	0.12067	0.09109
		Winter	N/A	0.09198	0.08063
SDG&E[242]	Schedule AL-TOU	Summer	0.11940	0.10954	0.07838
		Winter	0.10752	0.09174	0.07001

Figure 2 presents a simple diagram of how the crediting procedure would work under AB 2466.

Figure 2 Crediting Procedure for RES-BCT



4.6 RES-BCT Distribution of Credits

The credits would be subtracted from the benefiting account's normal billing cycle commodity (or generation) costs.[243] It is important to note that credits are calculated based on the commodity or generation portion of the applicable rate and applied to the commodity portion of the benefiting account. This is sometimes called "Gen to Gen," short for "generation to generation". If, during the billing cycle, the generation component of the electricity usage charges exceeds the bill credit, the benefiting account would be billed for the difference (local government pays).[244] As noted previously, the generating account and benefiting account do not need to be on the same rate, and the CPUC determined that the rate of the generating account does not automatically allow the benefiting account to be eligible for the same rate.[245]

If, during the billing cycle, the bill credit applied exceeds the generation component of the electricity usage charges, the difference would be carried forward as a financial credit to the next billing cycle (local government receives credit).[246] Credit cannot be carried forward more than 12 months; that is, at the end of a 12-month period, any remaining credit would be reset to zero and the local government would not receive any compensation.[247]

Additionally, the applicable IOU is not required to compensate a local government for energy produced in excess of the bill credits applied to the designated benefiting accounts.[248] Participation in this program also makes the local government ineligible to participate in other tariff or program that requires the IOU to purchase generation from that facility, such as a net energy metering tariff.[249] This means that while a local government customer that utilizes the RES-BCT cannot participate in a NEM tariff, the utility will use a NEM accounting mechanism to track generation credits from a generating account that will be applied to a benefiting account under RES-BCT.

4.7 RES-BCT Local Government or Campus Initiation or Termination of RES-BCT Participation

A local government must inform the electrical utility at least 60 days in advance that an eligible renewable generating facility will become operational.[250] The electrical corporation must then file an advice letter with the CPUC not later than 30 days after receipt of the notice proposing a rate tariff for the benefiting account(s).[251] The CPUC must approve or specify changes to the proposed tariff within 30 days of the date of filing.[252]

To terminate its participation in this arrangement, a local government must inform the electrical utility a minimum of 60 days prior to the proposed termination date.[253] If a local government sells its interest in the eligible renewable generation facility or sells electricity generated from that facility in way contrary to statutory requirements, no further bill credits will be earned past that day.[254]

4.8 RES-BCT Renewable Energy Credits (REC)

Similar to the way California handles renewable energy credits (REC) under net energy metering (as defined by California Public Utilities Code Section 399.12), the renewable energy generation system owner retains ownership of RECs under the crediting arrangement provided for in AB 2466.[255] Furthermore, electricity exported to the electric utility does not count toward the local electric utility's renewable portfolio standard (RPS) requirements, as defined (commencing with California Public Utilities Code Section 399.11).[256]

4.9 Program Limitations for RES-BCT

AB 2466 contains a total statewide limit (250 MW) for the amount of renewable energy generators that can participate in the crediting arrangement. Investor-owned electrical utilities are obligated to offer bill credits under AB 2466 until the rated capacity of eligible generators in their territory reaches its proportionate share of the 250 MW statewide limit based on the ratio of its peak demand to the total statewide peak demand as follows:[257]

- SCE: 123.8 MW (49.8%)
- PG&E: 104.6 MW (42.1%)
- SDG&E: 20 MW (8.1%)[258]

5. Examples from Other States

Other states have developed varied forms of community solar programs. This section provides brief summaries of the approaches taken by other states to promote community solar. Given California's current statutory treatment of community solar and the regulatory and utility structure, it is unclear how applicable these other models would be without legislative and regulatory changes.

5.1 Community Share Solar (Solar Gardens) Models

The following sections will provide an overview of the community solar gardens models employed by Colorado and Minnesota. These states passed legislation that allows utility customers to purchase agreed upon amounts of generation from a community solar project (generally developed by a third party). The community solar garden generates electricity and is connected to the utility distribution grid. Customers are credited with their percentage of generation from the solar energy project through the utility's billing system.

5.1.1 Colorado

Colorado passed legislation in 2010 instituting a community solar gardens implementation framework.[259] The legislation sought to provide access to solar for all residential and commercial customers and directed the Colorado Public Utilities Commission to adopt rules that include requirements for:

- Minimum capitalization;
- The share of a community solar garden's eligible solar electric generation facilities that a subscriber organization may at any time own; and
- Authorization for subscriber organizations to enter into lease, sale-and-leaseback transactions, operating agreements, and other ownership arrangement with third parties.[260]

The law allows any non-profit or for-profit entity (including a utility) to develop a community solar garden allowing for flexible development models.[261] The law defines community solar garden as:

> a solar electric generation facility with a nameplate rating of two megawatts or less that is located in or near a community served by a qualifying retail utility where the beneficial use of the electricity generated by the facility belongs to the subscribers to the community solar garden. There shall be at least ten subscribers. The owner of the community solar garden may

be the qualifying retail utility or any other for-profit or nonprofit entity or organization, including a subscriber organization organized under this section, that contracts to sell the output from the community solar garden to the qualifying retail utility. A community solar garden shall be deemed to be "located on the site of customer facilities".[262]

The law further defines subscription to a community solar garden as:

> a proportional interest in solar electric generation facilities installed at a community solar garden, together with the renewable energy credits associated with or attributable to such facilities under section 40-2-124. Each subscription shall be sized to represent at least one kilowatt of the community solar garden's generating capacity and to supply no more than one hundred twenty percent of the average annual consumption of electricity by each subscriber at the premises to which the subscription is attributed, with a deduction for the amount of any existing solar facilities at such premises. Subscriptions in a community solar garden may be transferred or assigned to a subscriber organization or to any person or entity who qualifies to be a subscriber under this section.[263]

Colorado's program uses net energy metering to track credits for generation and bill accordingly to a subscriber's account with excess credits carried forward on a month-to-month basis indefinitely until the customer terminates service (resulting in the credit expiring).[264] A subscriber is defined as a retail customer who owns a subscription and identified one or more physical locations to which the subscription shall be attributed.[265] The physical location must be within the same municipality or same county as the community solar garden.[266] If a subscriber resides in a county with a population of fewer than 20,000, the subscriber may subscribe to a community solar garden in adjacent county that has a population fewer than 20,000 provided that the same utility serves both the community solar garden site and the property being offset by the subscriber's subscription.[267]

Subscriptions are fully assignable and transferrable to any person or entity that qualifies as a subscriber.[268] Colorado also allows subscribers to change the premise to which the subscription is applied if the premise is within the geographical limits allowed (either the same municipality or county).[269]

The law mandated that each qualifying retail utility (e.g., Xcel Energy) create a plan (included in its compliance plan) to purchase the electricity and RECs from one or more community solar gardens subject to a three-year initial compliance requirement and subsequent Colorado Public Utilities Commission requirements.[270] The law expressly excludes municipal and cooperative utilities.[271] From 2011-2013, Xcel Energy was mandated to purchase the output from community solar garden systems of 500 kW or less at the same prices offered to similar onsite generation systems.[272] The legislation mandated that Xcel Energy acquire 50% of the solar gardens it plans to acquire during the first three years of the program and set a limit that these acquisitions not be more than 20% of Xcel Energy's retail generation standard (e.g., a RPS) during these years.[273] The law also required that Xcel Energy "not be obligated to purchase the output from more than six megawatts of newly installed community solar garden generation."[274] Beginning in 2014, the law requires the Colorado Public Utilities Commission to set minimum and maximum purchase requirements for Xcel Energy with regard to community solar gardens.[275] The Colorado Public Utilities Commission set the minimum amount at 6.5 MW and the maximum purchase at 30 MW.[276] Importantly, the electricity and RECs from these projects can only be sold to a qualifying retail utility with the utility purchasing all electricity and RECs generated[277] and receiving compensation for all unsubscribed energy and RECs through rate treatment.[278]

5.1.2 Minnesota

Minnesota uses a similar statutory structure for community solar gardens with at least nine utilities participating statewide, including co-ops.[279] This section will focus on Xcel Energy's program.[280] According to Xcel Energy's latest compliance filing from June 5, 2015, 425 applications were filed in the original initial cohort with 34 applicants withdrawing.[281] The remaining 391 applicants total 384.1 MW.[282] No application has been approved, and all applicants are still in various stages of review.

The legislation required Xcel Energy to administer a community solar gardens program and allowed other utilities to elect to develop a program as well. Minnesota law restricts the nameplate capacity of solar garden systems to no more than one MW and allows ownership by either a public utility or a third party that then sells the output to the utility.[283] The law also requires Xcel Energy to purchase all energy generated by a solar garden at applicable retail rates, as determined by the Minnesota Public Utilities Commission, with a possible future transition to a value-of-solar (VOS) rate.[284] The Minnesota Public Utilities Commission required Xcel Energy to make future filings that calculate the VOS rate for future discussions and comments with the first filing made on March 2, 2015, as well as the updated applicable retail rate filed on April 22, 2015.[285] Minnesota solar garden operators are also able to sell RECs to Xcel Energy at an approved rate or keep the RECs (such as RECs created from unsubscribed electric output) for other purposes.[286]

The Minnesota program requires at least five subscribers, with each subscription not representing more than 40% of the systems output. Each subscription must also be sized to supply no more than 120% (minimum of 200 watts) of the average annual consumption (averaged over a 24 months period) of electricity at the subscribing premise, when combined with other distributed generation resources serving the subscriber's premise.[287]

The Minnesota Public Utilities Commission also made the following determinations with regard to Xcel Energy's implementation plan:

- Set no limit on aggregate installed capacity of solar gardens;
- Required processing developer applications on a first-ready, first-served basis with specific milestones once an application is approved and a 24-month deadline to complete the project;
- Required solar garden operators to disclose detailed subscription costs and benefits to prospective subscribers;
- Set 25-year contract term that includes locking in the sale values of RECs for the 25-year term (new projects may be subject to different values); and

- Required the purchase of surplus bill credits annually.[288]

Other notable aspects of the program include the flexibility of subscription models that allow developers to ask for up-front payments, monthly payments, or pay as you go models.[289] This means that subscriber costs are project dependent. The program also allows subscribers to take their subscription with them if they move within the same county or adjacent county with the same electric utility provider (subscribers can sell or donate subscriptions if they cannot take them to a new location).[290]

5.2 Virtual Net Metering Models

Many states provide some type of virtual net metering or a similar mechanism to use existing NEM rules to access electricity generated from renewable energy. These programs range in options, with some states allowing single customers to aggregate meters on contiguous pieces of property and others allowing VNM across multiple meters owned by a single customer in the same utility service territory. Most of these programs allow systems up to one or two MW. A non-exhaustive list of these programs is provided below:[291]

- Colorado: Allows single customers with meters on contiguous properties to aggregate their meters.[292]

- Delaware: Allows for multiple customers to receive VNM from the electricity generated by a single renewable energy system, but also allows the utility to opt-out of VNM and make a single payment to the generator-host of the renewable energy system; Delaware also allows single customers to apply net metering credits to multiple meters at multiple properties as well as to leased or third party-owned systems.[293]

- Illinois: Utilities may choose to allow meter aggregation among multiple customers.[294]

- Maine: Up to ten customers can receive net metering credits from a single renewable energy system, so long as each benefiting customer is a part owner of the system.[295]

- Maryland: Individual agricultural, non-profit, and municipal customers are allowed to apply net metering credits to multiple meters.[296]

- Massachusetts: “Neighborhood net metering” rules allow net metering to multiple customers from a single renewable energy facility. The rules require that at least ten residential customers participate in a given project served by a single utility, but non-residential customers are also allowed if requirements are met.[297]

- New York: Remote net metering for farm and non-residential customers allows crediting to multiple meters on properties owned or leased by the same customer that are within the same utility territory and load zone as the NEM facility.[298]

- Oregon: Allows a single customer to apply net metering credits to meters across contiguous properties. There is no limit on the number of net-metering facilities per customer, as long as the capacity of all net-metering facilities on a customer's contiguous property does not exceed the applicable capacity limit. Meters on different rate schedules can be aggregated.[299]

- Pennsylvania: Allows a single customer to virtually net meter to properties within two miles of the renewable energy system so long as those properties are owned or leased and operated by the same customer.[300]

- Rhode Island: A system generally must be owned by the customer of record and sited on the customer's premises (in the same geographic location). However, facilities: (1) owned by public entity or multi-municipal collaborative; or (2) owned and operated by a developer on behalf of public entity or multi-municipal collaborative through "public entity net metering financing arrangement" are also eligible. Meter aggregation is generally allowed, and special provisions exist to accommodate meter aggregation for farm-based systems that serve facilities in close proximity to each other.[301]

- Utah: Allows for VNM to multiple meters at the same or adjacent location as the renewable energy system.[302]

- Vermont: "Group net metering" allows multiple customers or a single customer with multiple meters to apply net metering credits within the same utility territory.[303]

- Washington: Allows a single customer to apply net metering credits to multiple meters within a single utility territory (limited to 100 kW per customer).[304]

- West Virginia: Allows a single customer to apply net metering credits to multiple meters within two miles of the point of generation.[305]

6. Conclusion

This document has provided a summary of the existing state of shared/community solar in California and in other states. Access to shared solar programs under both the enhanced community and Green Tariff programs may well change or facilitate the expansion of solar PV across the state. VNM and aggregated net metering will also continue to add to the total number of systems while increasing the number of participants who consume renewable energy. These programs will evolve as statutory mandates change and regulators address new issues to help drive access to renewable energy and meet California's GHG and renewable energy procurement targets.

For updates and more information on the Southern California Rooftop Solar Challenge, visit www.energycenter.org/sunshot.

[1] See 2013 American Community Survey, 1-Year Estimates, US Census Bureau. Updated 9/2014: https://nmhc.org/Content.aspx?id=4708 .

[2] NMHC tabulations of 2013 American Community Survey, 1-Year Estimates. Updated 9/2014: https://nmhc.org/Content.aspx?id=4708 .

[3] Feldman, D., Brockway, A., Urlich, E. and Margolis, R., Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation, NREL U.S. DOE, April 2015, p. V.

[4] California Public Utilities Code Section 2831 – 2834.

[5] California Public Utilities Code Section 2830.

[6] PG&E, SDG&E, and SCE Joint Procurement Implementation Advice Letter Workshop Webinar, April 20, 2015, p. 15: https://www.sdge.com/sites/default/files/documents/1294761841/20150417_JPIAL_Webinar_Presentation_Final%20%281%29.pdf?nid=14086 .

[7] SMUD SolarShares, Frequently asked Questions, accessed 5/5/15: https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/solarshares-FAQ.htm .

[8] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[9] Solar Shares PV Array, Shared Renewables HQ, Accessed 5/5/15: http://www.sharedrenewables.org/index.php?option=com_projects&view=project_detail&id=82.

[10] SMUD SolarShares, Frequently asked Questions, accessed 5/5/15: https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/solarshares-FAQ.htm .

[11] Solar Shares PV Array, Shared Renewables HQ, Accessed 5/5/15: http://www.sharedrenewables.org/index.php?option=com_projects&view=project_detail&id=82.

[12] SMUD SolarShares, Frequently asked Questions, accessed 5/5/15: https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/solarshares-FAQ.htm .

[13] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf ; See also SMUD Rate Information: https://www.smud.org/en/residential/customer-service/rate-information/your-rates.htm .

[14] It is unclear exactly how these deals will progress and the exact rights and obligations under such an agreement as there currently is not an example of this type agreement with SMUD.

[15] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[16] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[17] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[18] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[19] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[20] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .

[21] Burke, J., SMUD's SolarShares Experience – A community Model, Solar Energy in inland Southern California Conference, February 6, 2014: http://www.cert.ucr.edu/events/solar2014/linked_agenda/JimBurke.pdf .
[22] SDG&E Filed Application (A.)12-01-008 *Application to Implement an Optional Pilot Program to Increase Customer* on January 17, 2012; PG&E Filed A.12-04-020 *Application to Establish a Green Option Tariff on* April 24, 2012.
[23] CPUC D.15-01-051 at 11 citing PG&E Settlement Agreement at 6-16.
[24] CPUC D.15-01-051 at 12.
[25] CPUC D.15-01-051 at 13.
[26] California Public Utilities Code Section 2831(b).
[27] California Public Utilities Code Section 2831.5(b)(2).
[28] California Public Utilities Code Section 2833(a).
[29] See California Public Utilities Code Section 2831-34.
[30] California Public Utilities Code Section 2833(d).
[31] California Public Utilities Code Section 2833(d)(1)(A).
[32] California Public Utilities Code Section 2833(d)(1)(B)(2).
[33] California Public Utilities Code Section 2833(d)(1)(B)(3).
[34] CPUC D.15-01-051 at 5.
[35] *Ibid.*
[36] CPUC D.15-01-051 at 5.
[37] CPUC D.15-01-051 at 2.
[38] California Public Utilities Code Section 2831(f).
[39] California Public Utilities Code Section 2833(c).
[40] California Public Utilities Code Section 2833(d).
[41] California Public Utilities Code Section 2833(d).
[42] California Public Utilities Code Section 2833(f).
[43] California Public Utilities Code Section 2833(q).
[44] CPUC D.15-05-051 at 18.
[45] *Ibid.*
[46] *Ibid.*
[47] *Ibid.* at 19.
[48] CPUC D.15-01-051 at 20.
[49] *Ibid.* at 20-21.
[50] *Ibid.* at 35.
[51] *Ibid.* at 29.
[52] *Ibid.* at 20-21 & 33.
[53] CPUC D.15-01-051 at 21, citing to D.14-11-042 at 94 & 22.
[54] CPUC D.15-01-051 at 21.
[55] *Ibid.*
[56]*Ibid.* at 21-22.
[57] *Ibid.* at 22.
[58] *Ibid.*
[59] *Ibid.*
[60] *Ibid.*

[61] *Ibid.* at 35.
[62] *Ibid.*
[63] California Public Utilities Code Section 2833(o).
[64] CPUC D.15-01-051 at 51.
[65] *Ibid.* at 51.
[66] *Ibid.* at 53-54.
[67] *Ibid.*
[68] *Ibid.* at 55.
[69] *Ibid.*
[70] *Ibid.*
[71] *Ibid.*
[72] *Ibid.*
[73] *Ibid.*
[74] *Ibid.*
[75] *Ibid.* at 56.
[76] *Ibid.* at 56-57.
[77] *Ibid.* at 57.
[78] *Ibid.*
[79] *Ibid.*
[80] *Ibid.*
[81] *Ibid.* at 58.
[82] *Ibid.*
[83] *Ibid.*
[84] *Ibid.*
[85] *Ibid.*
[86] *Ibid.*
[87] *Ibid.*
[88] *Ibid.*
[89] *Ibid.*
[90] *Ibid.*
[91] *Ibid.* at 60.
[92] *Ibid.* at 61.
[93] *Ibid.*
[94] *Ibid.* at 62.
[95] *Ibid.*
[96] *Ibid.*
[97] *Ibid.*
[98] *Ibid.* at 63.
[99] *Ibid.*
[100] *Ibid.* at 64.
[101] *Ibid.* at 66.
[102] California Public Utilities Code Section 2833(b).

[103] California Public Utilities Code Section 2833(b).
[104] CPUC D.15-01-051 at 49.
[105] *Ibid.* at 33.
[106] *Ibid.* at 24.
[107] *Ibid.* at 25.
[108] *Ibid.* at 29-30.
[109] SDG&E maximum is greater than the other IOUs to allow flexibility for SDG&E to consider projects of 20 MW in addition to EJ or ECR projects of 3 MW or less; See CPUC D.15-01-051 at 29.
[110] CPUC D.15-010-051 at 29.
[111] *Ibid.* at 72.
[112] *Ibid.* at 29.
[113] *Ibid.*
[114] *Ibid.* at 35.
[115] *Ibid.*
[116] *Ibid.* at 38.
[117] *Ibid.* at 35-36.
[118] *Ibid.* at 36.
[119] *Ibid.*
[120] *Ibid.* at 75.
[121] *Ibid.* at 74.; Advice letters must be filed by December 31, 2017.
[122] *Ibid.* at 74.
[123] California Public Utilities Code Section 2833(e).
[124] CPUC D.15-01-051 at 31.
[125] *Ibid.* at 31.
[126] *Ibid.* at 60.
[127] *Ibid.* at 61.
[128] *Ibid.*
[129] *Ibid.* at 31-31.
[130] California Public Utilities Code Section 2833(d)(1)(A).
[131] CPUC D.15-01-051 at p. 46, citing to California Public Utilities Code Section 2833(d)(1)(A)(i)-(ii).
[132] CPUC D.15-01-051.
[133] *Ibid.*at 48.
[134] *Ibid.* at 49.
[135] *Ibid.* at 50.
[136] *Ibid.* at 49.
[137] *Ibid.*
[138] *Ibid.* at 38-45.
[139] *Ibid.* at 44.
[140] *Ibid.* at 45.
[141] *Ibid.* at 75.
[142] *Ibid.* at 75-76.
[143] *Ibid.* at 77.

[144] *Ibid.*
[145] *Ibid.*
[146] *Ibid.*
[147] *Ibid.*
[148] California Public Utilities Code Section 2833(g).
[149] California Public Utilities Code Section 2833(h).
[150] California Public Utilities Code Section 2833(i).
[151] CPUC D.15-01-051 at 81.
[152] *Ibid.*
[153] *Ibid.* at 82.
[154] *Ibid.* at 84.
[155] *Ibid.*
[156] California Public Utilities Code Section 2833(p).
[157] California Public Utilities Code Section 2833(k).
[158] California Public Utilities Code Section 2833(l).
[159] California Public Utilities Code Section 2833(m).
[160] California Public Utilities Code Section 2833(n).
[161] CPUC D.15-01-051 at p. 33-34.
[162] *Ibid.* at p. 34.
[163] *Ibid.* at p. 86.
[164] *Ibid.* at pp. 86-87
[165] *Ibid.* at p. 88.
[166] *Ibid.*
[167] *Ibid.* at p. 90.
[168] *Ibid.* at pp. 90-92.
[169] *Ibid.* at p. 93.
[170] *Ibid.*
[171] *Ibid.* at p. 94.
[172] *Ibid*. at pp. 96-97.
[173] *Ibid.* at p. 102.
[174] *Ibid.* at p. 101.
[175] *Ibid.* at p. 103.
[176] *Ibid.* at pp. 98-100
[177] *Ibid.* at p. 106.
[178] *Ibid.* at p. 108.
[179] *Ibid.*
[180] *Ibid.* at 108-110.
[181] *Ibid.* at 113.
[182] California Public Utilities Code Section 2833(r).
[183] California Public Utilities Code Section 2833(u).
[184] California Public Utilities Code Section 2833(s).
[185] California Public Utilities Code Section 2833(t).

[186] CPUC D.15-01-051 at 45.
[187] *Ibid. at 45-46.*
[188] *Ibid.* at 45.
[189] *Ibid.* at 118.
[190] California Public Utilities Code Section 2833(j).
[191] CPUC D.15-01-051 at 85
[192] *Ibid.*
[193] *Ibid.* at 122.
[194] *Ibid.* at 123.
[195] *Ibid.* at 124.
[196] See CPUC D.15-01-051 at 125-128.
[197] California Public Utilities Code Section 2833(v).
[198] CPUC D.15-01-051 at 127.
[199] California Public Utilities Code Section 2833(w).
[200] CPUC D.15-01-051 at 135.
[201] *Ibid.* at 136.
[202] *Ibid.* at 137-138.
[203] See CPUC D.11-07-031 and D.08-10-036.
[204] See PG&E, Electric Schedule NEMVMASH: Virtual Net Metering For Multifamily Affordable Housing with Solar Generation. (2012); See also SF Environment: Virtual Net Energy Metering at Multitenant Buildings (2013) at p. 2.
[205] See CPUC D.6-01-024 (July 1, 2006).
[206] CPUC D.06-12-033 at 28.
[207] CPUC D.15-01-027 at 4.
[208] *Ibid.* at 23.
[209] *Ibid.* at 4.
[210] *Ibid.* at 5.
[211] *Ibid.* at 6.
[212] *Ibid.* at 2.
[213] *Ibid.* at 2, 26, &
[214] *Ibid.* at 40.
[215] *Ibid.* at 47.
[216] *Ibid.* at 2, 42-44.
[217] *Ibid.* at 44.
[218] See MASH Semiannual Progress Report, June 30, 2014, accessed at: http://www.cpuc.ca.gov/PUC/energy/Solar/mash.htm .
[219] California Public Utilities Code Section 2827 (h)(4)(b).
[220] *Ibid.*
[221] California Public Utilities Code Section 2830(a)(5) defines local government as: a city, county, whether general law or chartered, city and county, special district, school district, political subdivision, or other local public agency, if authorized by law to generate electricity, but shall not mean the state, any agency or department of the state, or joint powers authority. The legislature further amended this to include individual community college campuses,

individual California State University campuses, or individual University of California campuses under California Public Utilities Code Section 2830 (a)(1) & (3).

[222] *Ibid.*

[223] California Public Utilities Code Section 2830(b)(2) & (5).

[224] See California Public Utilities Code Section 2830(c)(1).

[225] California Public Utilities Code Section 2830(a)(6).

[226] California Public Utilities Code Section 2830(a)(1) & (3).

[227] *Ibid.*

[228] See California Public Utilities Code Section 2830(b).

[229] CPUC Resolution E-4283, April 22, 2010, at 20; California Public Utilities Code Section 2830(a)(4)(A).

[230] California Public Utilities Code Section 2830(a)(4)(D).

[231] California Public Utilities Code Section 2830(a)(4)(C).

[232] California Public Utilities Code Section 2830(a)(4)(E).

[233] California Public Utilities Code Section 2830(a)(4)(B).

[234] See California Public Utilities Code Section 2830(c).

[235] California Public Utilities Code Section 2830(a)(1).

[236] CPUC Resolution E-4283, April 22, 2010, at 21.

[237] CPUC Resolution E-4283, April 22, 2010, at 16.

[238] See California Public Utilities Code Section 2830(c).

[239] *Ibid.*

[240] PG&E Electric Schedule E-20, Service to Customers with Maximum Demands of 1000 Kilowatts or More, Sheet 4, Effective January 1, 2015: http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-20.pdf .

[241] SCE Schedule TOU-GS-1, General Service, Option A, Sheet 1-2, Effective March 2, 2015: https://www.sce.com/NR/sc3/tm2/pdf/ce143-12.pdf .

[242] SDG&E Schedule EECC Electric Energy Commodity Cost, Schedule AL-TOU, Sheet 4-5, Effective May 1, 2015: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC.pdf .

[243] See California Public Utilities Code Section 2830(c).

[244] *Ibid.*

[245] CPUC Resolution E-4283, April 22, 2010, at 21.

[246] *Ibid.*

[247] *Ibid.*

[248] California Public Utilities Code Section 2830(b)(9).

[249] *Ibid.*; CPUC Resolution E-4283, April 22, 2010, at 16.

[250] California Public Utilities Code Section 2830(f).

[251] *Ibid.*

[252] *Ibid.*

[253] California Public Utilities Code Section 2830(g).

[254] California Public Utilities Code Section 2830(g).

[255] California Public Utilities Code Section 2830(b)(8).

[256] *Ibid.*

[257] California Public Utilities Code Section 2830(h).

[258] CPUC Resolution E-4283, April 22, 2010, at 3.

[259] See Colorado Revised Statutes, 40-2-127 et seq. (2014).
[260] Colorado Revised Statutes, 40-2-127 (3)(b).
[261] Colorado Revised Statutes, 40-2-127 (3).
[262] Colorado Revised Statutes, 40-2-127 (2)(b)(I)(A).
[263] Colorado Revised Statutes, 40-2-127 (2)(b)(III).
[264] Colorado Revised Statutes, 40-2-127 (5)(b)(II).
[265] Colorado Revised Statutes, 40-2-127 (2)(b)(II).
[266] Colorado Revised Statutes, 40-2-127 (2)(b)(II).
[267] *Ibid.*
[268] Colorado Revised Statutes, 40-2-127 (2)(b)(II).
[269] Colorado Revised Statutes, 40-2-127 (2)(b)(II).
[270] Colorado Revised Statutes, 40-2-127 (5).
[271] Colorado Revised Statutes, 40-2-127 (7).
[272] Colorado Revised Statutes, 40-2-127 (5)(a)(II).
[273] *Ibid.*
[274] Colorado Revised Statutes, 40-2-127 (5)(a)(III).
[275] Colorado Revised Statutes, 40-2-127 (5)(a)(IV).
[276] Colorado Public Utilities Commission, Decision Approving Renewable Energy Standard Compliance Plan and Addressing Exceptions to Decision No. R14-0902, Decision No. R14-1505, Proceeding No. 13A-0836E (November 24, 2014), p. 15.
[277] Colorado Revised Statutes, 40-2-127 (5)(b)(I).
[278] Colorado Revised Statutes, 40-2-127 (5)(d).
[279] Participating Utilities include: Connexus Energy, Kandiyohi Power Coop, Lake Region Electric Cooperative, Mcleod Cooperative Power, Runestone Electric Association, Steele-Waseca Cooperative Electric, Tri-County Electric Cooperative, Wright-Henepin Cooperative Electric Association, and Xcel Energy.
[280] Xcel's Program was approved on September 17, 2014 by the Minnesota Public Utilities Commission, Docket No. E-002/M-13-867.
[281] Xcel Energy, Compliance Filing- Monthly Update- Community Solar Gardens Docket No. E002/M-13-867 (June 5, 2015).
[282] *Ibid.*
[283] Minnesota Statutes Section 216B.1641(a)-(b).
[284] Minnesota Statutes Section 216B.1641(g).
[285] Minnesota PUC Order Approving Solar-Garden Plan with Modification, Docket No. E-002/M-13-867, at 6.
[286] See Minnesota PUC Order Approving Solar-Garden Plan with Modification, Docket No. E-002/M-13-867, at 19.
[287] Minnesota Statutes Section 216b.1641(a)-(b).
[288] See Minnesota PUC Order Approving Solar-Garden Plan with Modification, Docket No. E-002/M-13-867, at 1-21.
[289] See Community Solar Gardens Fact Page: http://www.cleanenergyresourceteams.org/solargardens#current .
[290] *Ibid.*
[291] See SF Environment: Virtual Net Energy Metering At Multitenant Buildings at 7-8. This information was taken from DSIRE: Database of Energy Efficiency, Renewable Energy Solar Incentives, Rebates, Programs, Policy." DSIRE USA. North Carolina State University, 2013. http://www.dsireusa.org .

[292] Colorado Net Energy Metering Meter Aggregation, DSIRE Database (last updated 12/12/14), accessed 5/10/15: http://programs.dsireusa.org/system/program/detail/271 .
[293] Delaware Net Energy Metering Meter Aggregation, DSIRE Database (last updated 11/4/14), accessed 5/10/15: http://programs.dsireusa.org/system/program/detail/43 .
[294] Illinois Net Energy Metering, DSIRE Database (last updated 8/27/14), accessed 5/10/15: http://programs.dsireusa.org/system/program/detail/2700 ; See Meter Aggregation, ICC Staff Draft Party 465 Modification (October 9, 2014), Section 465.100, accessed 5/11/15: http://www.icc.illinois.gov/Electricity/NetMetering.aspx .
[295] Maine Net Energy Metering, DSIRE Database (last updated 9/2/14), accessed 5/10/15: http://programs.dsireusa.org/system/program/detail/280 .
[296]Maryland Net Energy Metering, DSIRE Database (last updated 4/21/15), accessed 5/10/15 http://programs.dsireusa.org/system/program/detail/363 .
[297] Massachusetts Net Energy Metering, DSIRE Database (last updated 8/6/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/281 .
[298] New York Net Energy Metering, DSIRE Database (last updated 4/30/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/453 .
[299] Oregon Net Energy Metering, DSIRE Database (last updated 8/5/14), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/39 .
[300] Pennsylvania Net Energy Metering, DSIRE Database (last updated 3/30/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/65 .
[301] Rhode Island Net Energy Metering, DSIRE Database (last updated 8/21/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/287 .
[302] Utah Net Energy Metering, DSIRE Database (last updated 4/10/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/743 .
[303] Vermont Net Energy Metering, DSIRE Database (last updated 4/3/14), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/41 .
[304] Washington Net Energy Metering, DSIRE Database (last updated 9/10/14), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/42 .
[305] West Virginia Net Energy Metering, DSIRE Database (last updated 3/16/15), accessed 5/12/15: http://programs.dsireusa.org/system/program/detail/2380 .