SUSTAINING SOLAR BEYOND NET METERING

How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

GRIDWORKS

Gridworks wishes to thank the following organizations for their contributions toward this paper: Borrego Solar, California Independent System Operator, California Solar Energy Industries Association, Clean Coalition, Office of Ratepayer Advocates, Pacific Gas & Electric, Regulatory Assistance Project, Sacramento Municipal Utility District, San Diego Gas & Electric, Southern California Edison, Sunrun, Tesla, The Utility Reform Network, Vivint Solar, and Vote Solar.

Views expressed herein are that of the author and are not endorsed by contributing organizations.

Research made possible through the generous support of the Heising-Simons Foundation.

GRIDWORKS

SUSTAINING SOLAR BEYOND NET METERING

How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

JANUARY 2018

INTRODUCTION

California has committed to rapid decarbonization of its power sector. The state is pursuing that objective through a wide range of policy solutions, one of which is net metering, an incentive encouraging customer adoption of renewable distributed generation, especially solar.[1] To date net metering has supported the adoption of solar by over 725,000 California customers, totaling nearly 6 GW of installed capacity.[2] These adoptions have contributed to reductions in greenhouse gas emissions from the power sector and local job creation. Net metering has been a success by many of California's key measures.

Looking forward, California's path to decarbonization assumes increased reliance on renewable energy, including estimates of up to 16 GW of behind the meter solar by 2030.[3] Achieving these targets would require accelerated customer adoption of solar. But as analyses of California's electric system have demonstrated, continued growth in generation during day-time solar peak periods creates two challenges: excess generation at the system-level and grid constraints at the distribution-level. Excess generation at the system-level has been demonstrated by increasing negative prices and resource curtailment, including of renewable generation.[4] Distribution-level grid impacts have been demonstrated through analysis of distribution system hosting capacity showing limited capacity to absorb mid-day solar production in areas of high-solar penetration.[5]

At their core, these challenges are the manifestations of

1 Use of the term "solar" throughout this paper implies behind the meter, customer owned solar generation.

2 http://www.californiadgstats.ca.gov/, October 23, 2017.

3 California Public Utilities Commission, see Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Plan and Related Commission Policy Actions, Attachment A: Proposed Reference System Plan. September 18, 2017. (http://cpuc.ca.gov/irp/proposedrsp/.)

4 "Q1 2017 Report on Market Issues and Performance." California ISO. July 10, 2017; "California wholesale electric prices are higher at the beginning and end of the day." EIA, 2017.

5 California Investor Owned Utility Reports on Integration Capacity Analysis for Distribution Resource Planning. December, 2016.

CONTENTS

misaligned power supply and demand. Going forward, rather than spread like seeds in the wind, solar energy needs to be planted at locations advantageous to the grid and needs to produce simultaneous with demand, or stored until there is demand. Solar alone will not suffice; it needs to be locationally targeted and co-located with storage. [6]

Meanwhile, California policy-makers have continued to push for differentiation of incentives for solar by location, ensuring grid costs are fairly recovered, and enabling customer choice. A clear need for balancing these objectives with the State's decarbonization imperative exists.

This paper reexamines net metering, asking how to build on its success to further California's decarbonization, account for location value, fairly recover grid costs, and enable customer choice. Evaluating alternative policies and applying consistent criteria reflective of California's principles this analysis identifies advantages and disadvantages to net metering and variations thereof. Based on this analysis we conclude California can sustain solar beyond net metering. We recommend California policy-makers move expeditiously to transition the state's solar compensation framework toward a net billing structure with locationally differentiated prices paid for exports. As detailed further in this paper, the transition may be eased in several ways and informed by data and insight gained through evaluation of current net metering policies, helping to sustain growth in customer adoption and achieve forecasted levels of solar.

DEFINING NET METERING AND VARIATIONS

KEY CONCEPTS UNDERPINNING NET METERING

The following section advances a standardized taxonomy and framework for net metering and its variations.

California Public Utilities Commission (CPUC) Decision (D.) 16-01-044 provides the following explanation of how net metering (NEM) works in California:

"Under NEM, customer-generators offset their charges for any consumption of electricity provided directly by their renewable energy facilities and receive a financial credit for power generated by their on-site systems that is fed back into the power grid for use by other utility customers over the course of a billing cycle. The credits are valued at the "same price per kilowatt hour" (kWh) that customers would otherwise be charged for electricity consumed. Net credits created in one billing period carry forward to offset customer-generators' subsequent electricity bills. At the end of every year that a customer-generator has been on the NEM tariff, the credits and charges accrued over the previous 12-month billing period are "trued-up." A customer producing power in excess of its on-site load over the 12-month period may be eligible for "net surplus compensation" under certain conditions."[7]

6 Decision 17-01-006, p. 4. California Public Utilities Commission; California PATHWAYS: GHG Scenario Results, Slide 14. April, 2015.

7 D.16-01-044, Page 13. CPUC.

Within this explanation are both physical (e.g., consumption) and financial (e.g., credit) concepts.

FIGURE 1

ILLUSTRATING PHYSICAL NET METERING CONCEPTS

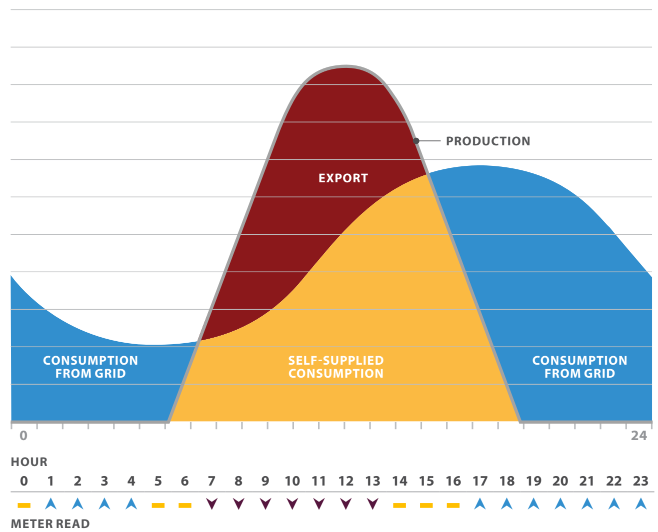


FIGURE 2

ILLUSTRATING FINANCIAL NET METERING CONCEPTS

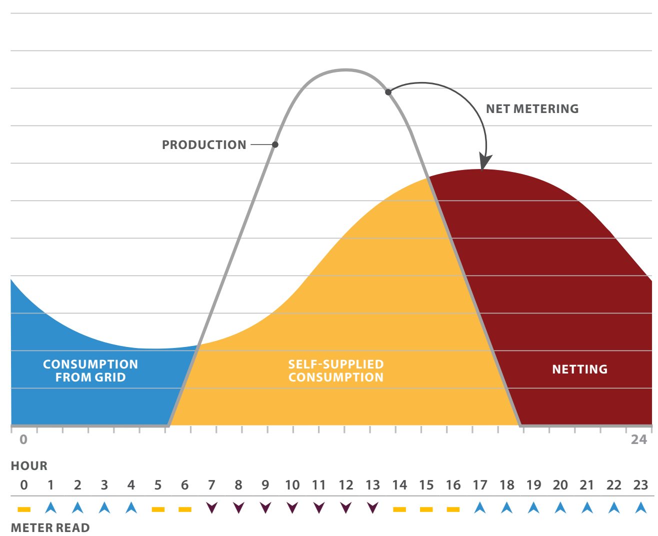


Figure 1 illustrates the physical net metering concepts, consumption and production of a customer generator over a single day. During different times of the day, production and consumption may or may not overlap, delineating the concepts of consumption from the grid, exports to the grid when on-site production exceeds consumption, and self-supplied consumption (self-supply). Self-supply, as illustrated here by the figure's yellow area, manifests as reduced consumption from the grid. These dynamics are manifest in the values recorded by the customer's meter, with values rising when consumption from the grid increases, flat when production and consumption are equal, and falling when exports increase.

Net metering overlays certain financial concepts on these physical ones to compensate customer generation. Most prominent is the concept of netting, as illustrated in Figure 2. Netting is offsetting a financial charge for consumption with a financial credit for production. As illustrated above, that offset can be physical and simultaneous as with self-supply (yellow area). Alternatively, netting can be non-simultaneous whereby credits for exports (maroon area) are carried forward to offset subsequent charges which would otherwise result from consumption from the grid (blue area). Key to understanding net metering is this delinking of the physical and financial: netting enables a customer to financially self-supply while consuming from the grid — while the meter read increases, the consumption charge does not.

Netting can be allowed at different intervals ranging from instantaneous to annual. Accounting for netting relies on reading a meter, so in practice the most granular netting interval for determining simultaneous self-supply is the most granular meter interval – how often the meter records a customer's consumption. In California, this is currently hourly for residential customers and 15-minute for commercial. The netting interval may have a substantial impact on the value of a solar investment for the adopting customer. Traditionally longer netting intervals are more advantageous for the adopting customer as seasonal variation in production and consumption allow for maximum netting. Customers with shorter netting-intervals, such as commercial customers, receive less benefit from netting.

CORE STRUCTURES | NET METERING, NET BILLING AND BUY ALL, SELL ALL

This analysis refers to alternatives to net metering as different core structures. The critical difference between core structures is what portion of production may offset charges for consumption, effectively compensating the customer for production at the rate she would otherwise be charged for consumption.

As summarized, a net metering compensation structure allows charges for consumption to be offset enabling compensation of all production at the consumption charge (netting). Two alternatives to net metering alter this approach to netting. The first alternative core structure is **net billing**, which awards credit to exports at a specified price which is different than the consumption charge. A net billing construct preserves self-supply, compensating the customer for the self-supplied portion of her production at the consumption charge. Credits awarded to exports are at a price other than the grid consumption charge, which may count against subsequent charges or be monetized. The second alternative core structure is buy all, **sell all (BASA)**, which relies on a dual-meter system to meter all production and all consumption separately. All production receives compensation at a price other than the consumption charge. Under a BASA framework, self-supply does not offset the customer's charges for consumption.

This formulation of core structures creates an important distinction between a compensation structure and the underlying rate design. In practice the two are intertwined, but the focus of this evaluation is how the overlaying compensation structure may be adapted. The limited exceptions to this approach are noted below.

Compensation of customer generation may be accomplished through adapting one of these three concepts to meet the goals of the jurisdiction. The following section describes the most accessible adaptations that can be made, constituting a tool kit available to policy makers.

THE TOOL KIT | CONSUMPTION CHARGES, EXPORT PRICES, ANCHORS AND ADDERS

Consumption charges, export prices, anchors and adders are tools that can be used to adapt one of the core structures to accomplish objectives.

The "consumption charge" is a charge to a customer for power consumed within a designated period. These charges in California today are largely volumetric for residential and small commercial customers. Furthermore, residential charges are tiered, such that the charges for consumption increase as consumption increases. A primary tool available to the policy maker is amending the consumption charge required of a customer generator. For example, in D.16-01-044 the CPUC required new customer generators to enroll in time of use (TOU) rates and pay certain non-bypassable charges on power exported to the grid in each metered interval (see dark blue section of Figure 1).

"Export prices," as used in this paper, is a term deliberately distinct from retail rate or consumption charges that instead refers to the compensation level paid to the customer for exports. BASA treats all production as an export. Net billing pays a price to exports (only), while compensating self-supply at the consumption charge. Under these constructs policy makers can adapt export prices to suit objectives. Export prices could be based on many factors, including where the resource is located, when the resource is delivering energy to the grid, and the market conditions that exist when the export occurs.

Beyond consumption charges and export prices, anchors and adders can be applied to achieve different objectives. The term "anchor" as used in this paper refers to a change to the customer compensation framework which reduces the customer's economic return to align their interest with other objectives, such as encouraging generation at times and locations of greatest value to the grid. An "adder" is the opposite, contributing to the customer's economic return in pursuit of additional advantage.

Anchors may include a fixed charge, minimum bill, standby rate, tolling fee for distribution of exported energy, demand charge, interconnection charge, prohibition on exports, or shorter netting intervals. Adders may include grid service payments, locational adders, environmental value, renewable energy credits, market transition credits, time of delivery adders, peak event-based adders or longer netting intervals. Complete definitions and references supporting these anchors and adders are provided in Appendix A.[8]

In sum, policy makers have a wide range of options between three underlying core structures, and the application of customer charges, export prices, anchors and adders. Appendix B illustrates how certain states and California stakeholders have applied these tools. Looking forward to California's future, the following section identifies a range of plausible options for consideration.

POTENTIAL COMPENSATION STRUCTURES FOR CALIFORNIA

In D.16-01-044 the CPUC asked staff and stakeholders to "explore compensation structures for customer-sited DG other than NEM, including analysis and design of potential optional or pilot tariffs, with a view to considering at least an export compensation rate that takes into account locational and time-differentiated values of customer-sited DG."[9] In the spirit of this call to action, the following potential compensation structures for California were identified through stakeholder engagement and research on how other states are compensating customer generation. These options do not represent an exhaustive list of possible compensation frameworks, rather a reasonable cross-section reflecting ongoing trends in California's energy policy landscape. This section introduces those options; a later section evaluates them.

Several new concepts are included within these options. They are introduced in the context of the following explanations of each option.

8 Appendix A and B are posted at www.gridworks.org

9 D.16-01-044, p. 103. CPUC.

TABLE 1

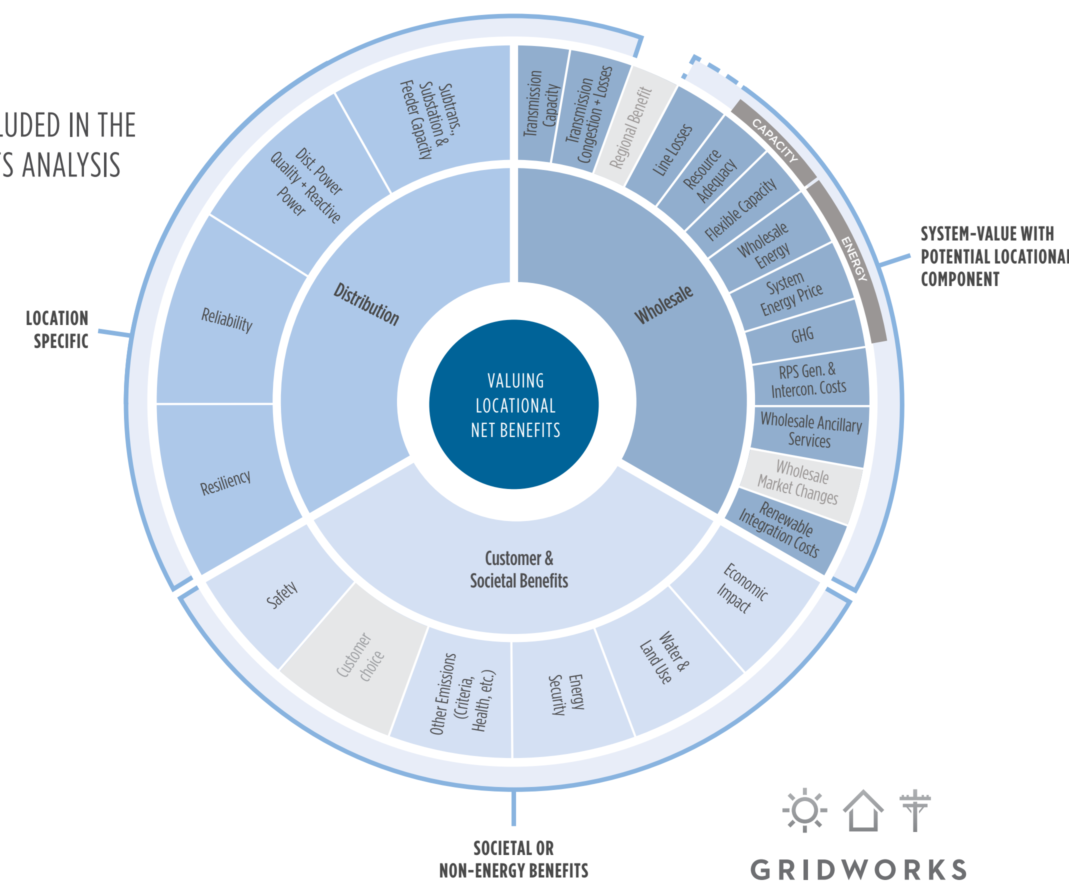
	OPTION NAME	SELF-SUPPLY	EXPORT PRICE	ADDER/ANCHOR
1	NEM 2.0	Y	Retail Rate	Selected Non-bypassable charges; Time of Use Rate[10]
2	Net Billing	Y	Locational Value	Transferrable Credit; Transition Credit; Opt-in Grid Services
3	Net Billing + Grid Services	Y	Market Price	Transferrable Credit; Managed Demand Charge
4	Buy All, Sell All	N	Locational Value	Transferrable Credit; Transition Credit
5	BASA + Grid Services	N	Market Price	Transferrable Credit

10 To allow for comparison, the following assumptions are held constant throughout these options: current CPUC policy on minimum bill charges, non-bypassable charges, TOU rates, netting and true up intervals remain unchanged unless explicitly noted; no unidentified anchors or adders incremental to those identified here are applied.

FIGURE 3

VALUE COMPONENTS INCLUDED IN THE LOCATIONAL NET BENEFITS ANALYSIS

Analyzed
Not analyzed



OPTION 1 | NEM 2.0

This option reflects the status quo. The only exception to current practice we contemplate is the possibility of further evolution of TOU rates to allow those rates to more specifically reflect grid conditions, including a) greater peak-to-off-peak rate differentials, b) greater locational rate specificity, and c) further shifts in TOU periods on daily or seasonal basis.

OPTION 2 | NET BILLING

This option reflects a net billing core structure with exports compensated at the resource's Locational Value, an export price informed by the **Locational Net Benefits Analysis (LNBA)**.[11] The LNBA is a methodology being developed under the supervision of the CPUC which differentiates the value of customer generation by location, as illustrated in Figure 3.

Depending on how the administratively set locational values are determined, this export price could differ between customers. To enable a predictable return for the investing customer, it is assumed that the export price paid to an enrolling customer would be fixed for a practical duration and variable following that duration, updated periodically, based on refreshed LNBAs. It is assumed the valuation is updated annually to allow newly enrolling customers to be compensated at refreshed pricing.

Two additional features of this option may be considered to support customer adoption. First, would be the inclusion of a Market Transition Credit.

MARKET TRANSITION CREDIT | Awarding additional temporary compensation to a customer generator during a defined period (e.g., 5 years, indexed to total customer adoption, up to percent of system peak) that ramps down over time but recognizes the importance of continued clean energy development.

There are many ways such a credit could be structured. Here we envision a "step- down" Market Transition Credit, whereby an adder to the LNBA-based export price tapers down to zero out over time. The scale and pace of the step-down could be benchmarked to installed capacity, like early California Solar Initiative rebate designs.

TRANSFERRABLE CREDIT | Allowing credit earned by a customer generator for exports to the grid to be transferred to any other customer at the discretion of the customer generator.

11 For additional background on the LNBA, see for example, Southern California Edison Compnay's Demonstration Project B Final Report at https://drpwg.org.

Because the net billing framework suggested here compensates exports at a price reflecting their Locational Value, credits earned for these exports could be transferred to any other customer. The impact of transferrable credits would depend on whether the generator must be "sized-to-load," as is the case under NEM 2.0. We envision that requirement being lifted.

Finally, we contemplate the exports may also be eligible for participation in grid services on an opt-in basis.

GRID SERVICES | Market-based compensation for DER providing energy, capacity, voltage support, frequency regulation and resiliency pursuant to an identified grid need. Compensation may be at wholesale or distribution level.[12]

Compensation to customers opting into grid services would be an alternative to administratively determined export prices, such that the customer chooses one or the other, but is not eligible for both.

OPTION 3 | NET BILLING + GRID SERVICES

This option reflects a net billing core structure with exports compensated at market prices based on their participation in grid services markets. Whereas in Option 2 the customer would be defaulted onto the administratively determined LNBA-informed export price with the option to opt-in to grid services markets, Option 3 would default the customer's exports into grid services markets. It is assumed that aggregators will serve as the customer's agent in participating in such markets, but individual customer participation is not precluded.

MARKET PRICE | Prices paid for grid services may be market-based resulting from competitive solicitations, participation in organized wholesale markets or other transaction platforms. Distinct from other contemplated pricing mechanisms which result from administrative value determinations (e.g., locational value, retail rate).

An additional feature of this option would be **a managed demand charge**.

12 Wholesale Grid Services may include: energy, regulation up, regulation down, spinning reserve, and non-spinning reserve. Detailed service definitions at http://www.caiso.com/participate/Pages/MarketProducts/Default.aspx. In addition DER aggregations may be eligible to provide system, local or flexible resource adequacy capacity (RA). Designation of a DER/DERA for RA entails must-offer obligations (MOO) under the ISO tariff to participate in the markets for these wholesale grid services. Distribution Grid Services may include: energy (up/down), capacity (up/down), and voltage/volt ampere reactive (VAR, up/down). Distribution service definitions are detailed in CPUC D. 16-12-036.

MANAGED DEMAND CHARGE | A rate design feature in which a customer receives a charge based on their maximum electric capacity usage during a defined interval in which capacity to serve customers is relatively scarce. Customers can reduce or avoid the charge through reduction of maximum usage through generation, changes in consumption, or use of storage technology to shift load.

This feature is highlighted because it may provide a meaningful opportunity for a utility to recover costs for grid services unless the need for those services is reduced by a customer's change in consumption or adoption of a storage technology. Volumetric charges may be reduced for customers receiving a demand charge.

OPTION 4 | BUY ALL, SELL ALL

This option reflects a buy all, sell all core structure with all production compensated at its Locational Value. An additional feature of this Option would be the inclusion of a Market Transition Credit.

As summarized, customer consumption is metered separately from production, enabling customer participation in other programs such as demand response to be evaluated and rewarded distinctly.

OPTION 5 | BUY ALL, SELL ALL + GRID SERVICES

This option reflects a buy all, sell all core structure with all production compensated at market based export prices based on their participation in grid services markets. Whereas in Option 4 the customer would be defaulted onto the administratively determined Locational Value export price, Option 5 would default the customer's production into grid services markets. It is assumed that aggregators will serve as the customer's agent in participating in such markets, but individual customer participation is not precluded.

In the next section, we turn to criteria which may be used to gauge the relative strengths of these options and an evaluation of their merits.

EVALUATING IDENTIFIED OPTIONS

Returning to the identified opportunity: net metering has proven potential to incentivize customer adoption of solar. But does net metering support the alignment of supply and demand and thereby help resolve key challenges facing California? Can those challenges be addressed while increasing affordability for all customers and preserving customer choice?

PRINCIPLES

To evaluate the identified compensation structure options, criteria consistent with California's principles must be identified. This evaluation begins with the stated principles of the CPUC in its DER Action Plan[13] and supplements them based on stakeholder input, resulting in the following foundational principles:

Adapted from the CPUC's DER Action Plan

- DER able and incentivized to serve grid needs (Vision Element 2.A)
- Technologically neutral, competitive sourcing (Vision Element 2.C)
- DER valued fully, accurately, and impartially (Vision Element 2.D)
- Sourcing reflects locational value (Action Element 2.3)

Incremental to DER Action Plan

- Grid valued fully, accurately, and impartially; recognized as essential
- Customer choice enabled, practical and informed
- DER should contribute to GHG reductions
- Valuation and incentives determined transparently
- Grid and energy services unbundled
- New technology leveraged to serve customers
- Grid peak-driven infrastructure investment minimized
- Increase affordability of service for all customers
- Ratepayer indifference
- California's solar market grows sustainably

These principles represent a broad range of values and priorities held by policy makers, utilities, market participants, consumer advocates, and environmental interests.

CRITERIA

To operationalize these principles and enable a practical evaluation of the options, the following criteria were derived: Locational Value, Grid Cost Recovery, Customer Choice and Decarbonization. These criteria have been defined as follows for the purposes of this evaluation.

Locational Value

This criterion asks whether the option compensates a customer generator for the locational value of its production as informed by the LNBA. Underpinning this criterion is the CPUC's 2017 endorsement of the LNBA, which states, "the presumption is that the next regime of NEM incentives would be tailored to the relative costs and benefits of DER

13 "DER Action Plan." May 2017. CPUC.

deployment at given locations on the grid."[14]

Principles embedded in this criterion include: *DER valued fully, accurately, and impartially; Sourcing reflects locational value; Valuation and incentives determined transparently; Increase affordability of service to all customers; Peak-driven infrastructure investment minimized*

Grid Cost Recovery

This criterion asks how well the option recovers utility grid costs consistent with cost-causation principles and cost allocation. Because no new fixed or grid charges are assumed for the options under consideration in this evaluation the practical impact of this criterion is to advantage options which limit netting. Underpinning this criterion is the CPUC's conclusion from D.16-01-044, "the principal potential disadvantage of continuing the current full retail rate NEM tariff is economic. The [Investor Owned Utilities] lose revenue from NEM customers, particularly residential NEM customers, because those customers pay less to cover distribution costs through their volumetric rates. This revenue is recovered through increases in rates paid by all customers."[15] Therefore options satisfying this criterion better enable the utility to recover distribution costs which are incurred on an adopting customer's behalf through collecting consumption charges for consumption from the grid.

Principles embedded in this criterion include: *Grid valued fully, accurately, and impartially; Increase affordability of service to all customers; Ratepayer indifference*

Customer Choice

This criterion asks how well the option enables the customer to make an informed choice in adopting DER and whether the option allows customer self-supply. Options satisfying this criterion reflect relative simplicity, clarity, and predictability over the life of an asset from an investing customer's point of view, while enabling self-supply. Embodied in the criterion is recognition that customer generation needs to be financeable, which may imply fixed pricing for a period.

Principles embedded in this criterion include: *DER valued fully, accurately, and impartially; Customer choice enabled, practical and informed; Valuation and incentives determined transparently*

Decarbonization

This criterion asks how well an option contributes to high-renewable scenarios critical to achieving decarbonization targets, especially through encouraging co-location of solar with energy storage. Effective options increase grid flexibility, complementing variable renewable resources by responding to changes in renewable output, providing load shift, ramp, voltage, and/or frequency support. Successful decarbonization policy includes incentives for adopting and leveraging emerging inverter and storage capabilities.

Principles embedded in this criterion include: *DER able to serve grid need; DER contribute to GHG reductions; Leverage new technology to serve customers and the grid; Peak-driven infrastructure investment minimized*

Three principles of the evaluation that were not embedded in the criteria are "technologically neutral, competitive sourcing (Vision Element 2.C)," "unbundling grid and energy services," and "California's solar market grows sustainably." The first was deemphasized because competitive sourcing through distribution and competitive wholesale markets remains an uncertain dimension of California's energy markets. At this time the relative uncertainty of how these markets will work for customer generators, the size of the markets, and whether they will serve to support solar adoption lead the authors to focus on more near-term, predictable principles. The second, unbundling grid and energy services, was deemphasized because it was assumed achievable through any of the options analyzed. The third, growing California's solar market sustainably, is treated as an overarching objective and addressed in the following section, "conclusions and recommendations."

The following section evaluates the identified potential compensation structure options using these criteria.

OPTION EVALUATION RESULTS

The purpose of evaluating the compensation structure options using these criteria is to assess which structures may enable customer generators to make further contributions to the identified principles and criteria. Table 2 shows the relative advantages of each option.

TABLE 2

EVALUATING CUSTOMER GENERATION COMPENSATION OPTIONS

	OPTION	LOCATIONAL VALUE	GRID COST RECOVERY	CUSTOMER CHOICE	DECARBONIZE
1	NEM 2.0	● (dark red)	● (orange)	● (blue)	● (orange)
2	Net Billing	● (yellow)	● (yellow)	● (yellow)	● (yellow)
3	NB + Grid Services	● (orange)	● (yellow)	● (orange)	● (light green)
4	BASA	● (blue)	● (blue)	● (orange)	● (dark red)
5	BASA Grid Services	● (orange)	● (blue)	● (dark red)	● (blue)

SCALE BETTER ● (blue) ● (light green) ● (yellow) ● (orange) ● (dark red) WORSE

To explain the evaluation results we consider the relative strengths of each option sequentially by criterion.

The strengths of each option relative to the Locational Value criterion hinge on whether the core structure compensates a customer generator at a locationally differentiated value. NEM 2.0 and BASA are opposite in this regard, compensating

14 D.17-08-026, p.44. CPUC.
15 D.16-01-044, p. 81. CPUC.

none and all of production at the Locational Value respectively. Net Billing allows for compensation of exports (only) at the Locational Value. The two Grid Services options rely on market based pricing which may be driven by relative costs and benefits, but unrelated to the LNBA valuation — the export price may be above or below the LNBA-informed price.

The strengths of each option relative to the Grid Cost Recovery criterion depend on whether the utility's distribution costs are recoverable through the adopting customer's volumetric rates. The options ascend in their ability to satisfy this criterion based on how much of the customer's consumption results in a charge: more charges, more cost recovery.

The strengths of each option relative to the Customer Choice criterion reflect the relative simplicity of the transaction from a participating customer point of view and whether the option allows customer self-supply. Here Net Metering has historically proven effective, underpinning the adoption of solar by over 725,000 customers in California; however, the predictability of the customer's return on investment is only as predictable as the underlying rate design, which is increasingly dynamic in California. At the more extreme edge of customer choice lie options defaulting customers into grid services markets, introducing new complexity relative to the alternatives and lowering the ease of engagement by customers. BASA is arguably the simplest transaction structure: customer gets paid a fixed export price for all production for a predictable period, as with a feed-in tariff; however, the structure prohibits customer self-supply, a significant limitation of customer choice. Net Billing mixes two options which are simple when separate, but potentially more complicated when put together.

Finally, the strengths of each option relative to the Decarbonization criterion depend on how well it enables the customer generation to support high-renewable scenarios. Relative to its predecessors, NEM 2.0 begins a transition to incentivizing grid integration through requiring customers to enroll in time of use rates, giving an adopting customer a nudge to orient and size their installation toward production profiles of relative advantage to the grid.

Net Billing goes further to support decarbonization. With Net Billing, the value of self-supply increases relative to exports, pushing the customer toward greater alignment and adoption of storage. Finally, options which default customers into grid services markets provide a distinct advantage: the sourcing of these resources follows an identified grid need. Relative to the "scatter shot" approach to DER deployment underpinning the other options, these advantages are significant from a decarbonization point of view. BASA does little to support decarbonization: neither self-supply nor grid services are brought to bear to support alignment of solar supply and demand. This short-coming could be mitigated by time-differentiated export prices, an option not explored in depth by this analysis.

Overall, the evaluation demonstrates net metering, other core structures, and the tool kit can be honed in pursuit of defined objectives. While Net Billing achieves average results across criteria, the others excel and fall short in various ways. Therefore, the relative weighting would have a significant impact on whether any option stands out.

CONCLUSIONS AND RECOMMENDATIONS

KEY QUESTIONS EMERGING FROM EVALUATION

This evaluation brings the following key questions into focus.

How should the success of NEM 2.0 be assessed?

NEM 2.0 implementation began in 2016 and 2017. While the impacts of this approach are not yet well understood, interconnection data show customer applications are slowing, as featured below in Table 3.[16]

TABLE 3

	Q4 2015	Q4 2016	Delta	Q1 2016	Q1 2017	Delta	Q2 2016	Q2 2017	Delta
Non-Residential	810	906	12%	858	975	14%	1,360	386	-72%
Residential	41,527	33,630	-19%	39,634	26,484	-33%	36,875	16,517	-55%

To date the residential sector has slowed most significantly. Because submission of an interconnection application significantly lags development for non-residential customers, data for this segment will likely show a drop in forthcoming quarters.

There are numerous factors impacting solar adoption in California; concluding this trend is solely attributable to NEM 2.0 oversimplifies the analysis. We suggest the following questions be monitored in 2018 to inform future decisions concerning the effect of NEM 2.0 and contemporary factors. Insights gained from the current structure may be leveraged to support California's next steps.

- **GHG Reductions:** How are existing customer generators contributing to decarbonizing California's power supply? Will new resources have the same impact, diminishing, or increasing?
- **Market Conditions:** Are customers continuing to enroll in net metering? Is the market steady, growing, or contracting? What are growth expectations going forward?
- **Impact of TOU requirement:** Has requiring enrollment in TOU rates for residential net metering customers affected

16 Derived from www.californiadgstats.com. August, 2017.

enrollment in net metering? Has it affected the sizing and orientation of systems? Has it affected the adoption of storage technologies by residential customers?

- **Cost/Benefit:** Are the costs and benefits of NEM 2.0 improved relative to NEM 1.0?

An evaluation of these metrics and questions may serve as a useful foundation for future decision making regarding the merits of NEM 2.0.

Is eliminating a customer's self-supply practical and advantageous?

The BASA options evaluated here would require regulatory limits on self-supply. For the relative advantages of those options to be gained, this limit would need to be physically practical, which may not be assumed. Data on customer owned generators directly serving load behind the meter out of parallel with the grid are limited, but anecdotal evidence suggest it may be impractical to limit the self-supply of motivated customers. The likelihood of customers "cutting the cord" if self-supply is precluded, even for a portion of their load, may warrant further evaluation.

In addition, self-supply has been a primary value-add for adopting customers. A compensation structure that eliminates this value stream must either replace it or, all other things being equal (e.g., customer generator system costs remain consistent), expect declining growth in customer adoption. The net billing options identified here preserve self-supply, effectively pitting retail rates against declining technology cost curves, especially that of storage. This competition may be a productive incentive to support storage adoption while enabling customer generators to make needed contributions to grid flexibility and affordability.

What are the practical challenges of using the LNBA as proposed?

The Net Billing and BASA options rely on the LNBA: the former as a source to inform pricing of exports; the latter for all production. As referenced here, the CPUC has indicated a consistent commitment to locationally differentiated incentives for customer generation, citing the potential for such targeting to reduce the need for investment in transmission and distribution grid infrastructure and local generation resources, while easing grid operations. That body has also acknowledged challenges facing the LNBA methodology in fulfilling this role and ordered further improvements.[17]

Implementation of the ordered improvements will continue iteratively over time; perspectives on its effectiveness will differ; and uncertainty about its fitness for use in valuation will continue — of all conclusions in this analysis, this is perhaps most assured. These conclusions are doubly certain if the methodology is to serve a price-setting function. This is the hazard of a compensation framework which relies on administratively determined prices; one which is equally applicable to the administratively determined retail rate as it is for the LNBA. The buyer may be paying too much, or too little. Unless and until market pricing alternatives identified in the grid services options can serve as viable alternatives, there may be uncertainty about valuation.

Three further challenges to reliance on the LNBA deserve consideration: How will customers accept differentiated incentives? How will utilities process them? And how will vendors adapt marketing of DER under them? Customers may be confused or put off by receiving a different incentive than their in-laws a circuit over; utilities billing systems may require significant investment to track a level of granularity which has never been applied to retail ratemaking; and vendors may be challenged to effectively market or finance their services with specificity? There are three potential ways to address these challenges. First, technological solutions which empower the customer and utility to adapt to more price signals. Second, careful consideration of what the appropriate level of granularity might be. From the service territory, to distribution planning area, to groups of circuits, to circuits, to feeders, to individual customers: there is wide range of granularity enabled by the LNBA methodology. Third, offering all customers a base price for exports regardless of location with adders for locations of particularly value. Arriving at a practical level of granularity may require transition from broad to narrow and experimentation. Technologies which allow both customers and utilities to adapt may be tested, preferably with a sense of urgency.

Are grid services markets viable?

Net Billing and BASA structures would allow for exports or all production to enter grid services markets. Grid services markets include:

- **Wholesale Grid Services:** Under current CAISO tariffs, DER may bid market energy, regulation up, regulation down, spinning reserve and non-spinning reserve.[18] However, active participation by DER providers has been limited. The CAISO has recently renewed an effort — its Energy Storage and Distributed Energy Resources stakeholder initiative — to address challenges associated with DER participation in wholesale markets.[19] The CPUC has provided comparable commitments.[20]

- **Distribution Grid Services:** Through the CPUC's Distribution Resource Planning and Integration of Distributed Energy Resources proceedings, plus individual initiatives of Southern California Edison, numerous distribution grid services demonstration projects are underway. These demonstrations constitute the onset of California distribution services market, in which third-party aggregated DER provide capacity, voltage support, and resiliency services to the distribution system.[21]

17 D. 17-09-026

18 Detailed service definitions at http://www.caiso.com/participate/Pages/MarketProducts/Default.aspx

19 Energy Storage and Distributed Energy Resources Stakeholder Initiative, CAISO.

20 D.17-10-017; R.15-03-011. CPUC.

21 D.16-12-036. CPUC.

The integration of DER into wholesale and distribution markets has been a priority for California, but their viability remains uncertain. Through the referenced CAISO and CPUC initiatives the viability of grid services markets will become clearer. 2018 will be a pivotal year in this regard.

RECOMMENDATIONS

This evaluation attempts to evenly balance criteria and concludes that Option 2, Net Billing with exports compensated at the LNBA-informed export price for solar would be a substantial improvement to current policy, allowing for locationally differentiated compensation, improved grid cost recovery, and deeper decarbonization though storage enabled alignment of solar supply and demand.

This structure would lead to three potential outcomes:

- where the LNBA-based price paid on exports provides an adequate return, customers will adopt solar (with or without storage) in areas advantageous to the grid, easing grid planning and operations while lowering grid costs;
- where the LNBA-based price paid on exports does not provide an adequate return, customers are incentivized to maximize self-supply, most practically achieved through solar plus storage;
- where neither the LNBA nor storage are advantageous to the customer, they will maintain the choice to adopt while making increased contributions to grid cost recovery.

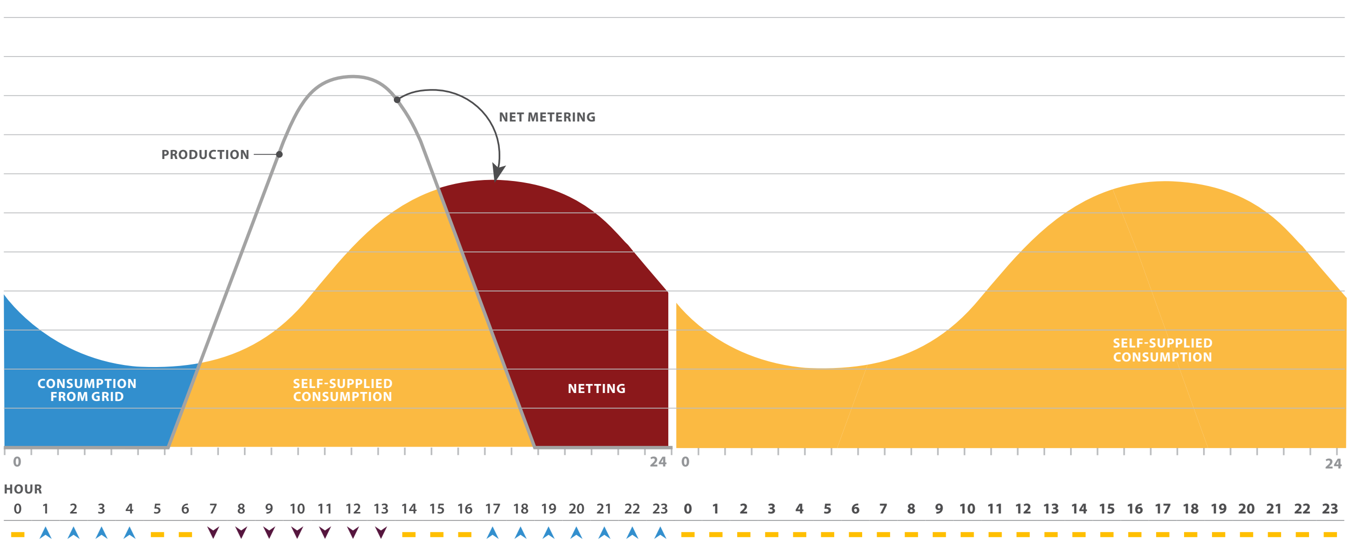
These advantages are more acute where and when mature grid services markets can replace the LNBA as a tool for pricing exports. As more experience with grid services is gained, these advantages may become increasingly practical.

To ease the transition from NEM 2.0 to Net Billing, two measures are recommended. First, enable Transferable Credits, allowing credit earned by a customer for exports to be transferred to other customers at the discretion of the customer generator. This will introduce liquidity into the market, especially if "size-to-load" requirements are lifted, allowing customers who are not in high-value locations to invest in those locations and receive corresponding reductions in their energy costs. Second, adopt temporary Market Transition Credits, smoothing the change from the current compensation levels to locationally differentiated levels. There are many ways this could be structured. One would be to "step- down" the Market Transition Credit in stages as the industry hits certain installed capacity benchmarks (similar to early California Solar Initiative designs). This step-down approach would have the added advantage of allowing for storage to scale up and reduce costs while signaling to industry that there will be a market for behind the meter storage.

Timely adoption of a Net Billing structure may also pave the way for grid friendly transportation electrification. Net metering would allow non-simultaneous netting of vehicle electrification load, an accounting tool which would undermine a principal benefit of vehicle electrification from a societal perspective (i.e., increased throughput leads to decreased rates). To the extent net metering continues into the next decade when electric vehicle adoption is forecasted to surge, a huge class of customers may come to expect low or zero cost service from the grid. On the other hand, a Net Billing structure would encourage electric vehicle customers to charge while the sun shines, or store their solar-generated energy to charge their vehicles at other times.

FIGURE 4

FROM NET METERING TO NET BILLING, SOLAR TO SOLAR PLUS STORAGE



A final advantage of Net Billing deserves consideration: Net Metering's reliance on the retail rate limits the flexibility of California policymakers – the price paid to solar is intertwined with retail ratemaking, a clunky policy making process with implications and complications extending far beyond customer generation. This approach has supported customer adoption to date because retail rates were going up and solar costs were coming down. It is not difficult to imagine these trends being reversed, with federal trade or tax policy turning against solar. Net Billing on the other hand compensates exports at a price determined by California policy-makers, allowing for the adoption of anchors and adders with relative ease compared to Net Metering. In this sense, Net Billing allows California alone to determine whether solar is sustained.

Based on this evaluation we recommend California policy-makers move expeditiously to transition the state's solar compensation framework toward a Net Billing structure. As provided, the transition may be eased in several ways and informed by data and insight gained through evaluation of NEM 2.0, helping to sustain growth in customer adoption and achieve the levels of forecasted solar adoption.

APPENDIX A

DEFINING ANCHORS AND ADDERS

Anchors

- *Minimum Bill*
  A minimum bill or minimum charge is the minimum amount that the utility can charge customers for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs. Also referred to as *minimum charge*[22,23,24]

- *Standby Rate*
  Standby rates are designed to cover the cost of standby electric service when a customer generator is not operating as intended. Currently California NEM eligible customer generators are exempt. Also referred to as *standby fees* or *standby charges*.[25,26,27,28]

- *Non-Bypassable Charge*
  A volumetric charge applied on all customers' bills (even if they purchase electricity from another supplier). For California NEM customers, this can apply to netted out consumption from the grid (1.0) or to total consumption from the grid during each metered interval (2.0).[29,30,31]

- *Demand Charge*
  Charge for electric service based on the consumer's maximum electric capacity usage and calculated based on the billing demand charges under the applicable rate schedule. Currently, demand charges only apply to commercial and industrial customers in California.[32,33]

- *Interconnection Charges*
  A charge levied by network operators on other service providers to recover the costs of the interconnection facilities (including the hardware and software for routing, signaling, and other basic service functions) provided by the network operators.[34,35]

- *Required Time of Use Rate*
  Requirement that a customer generator enrolls in a time of use rate as a condition of net metering.

- *Prohibition on Exports*
  Prohibiting the exports of power from a customer generator to the grid. This may be limited to particular intervals.[36,37]

22 CPUC: "A minimum bill or minimum charge is the minimum amount that the utility can charge customers for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs... Some utilities calculate minimum bill as a daily charge, which will add up over the course of the month to roughly $5 or $10." http://www.cpuc.ca.gov/General.aspx?id=12187

23 SCE: "The minimum charge (also referred to as the Balance of Minimum Charge or the 'Bal of minimum charge' as it may appear on your bill) is a delivery charge that helps support the maintenance and operation of providing electricity. This charge is calculated on a daily basis and only applies when your total Delivery Charges for the month fall below approximately $5 for those enrolled on California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), multifamily and medical baseline rate plans or approximately $10 for all other residential users." https://www.sce.com/wps/wcm/connect/8245d565-abae-4419-9d33-40ab30d8ae14/SCE_FrequentlyAskedQuestions_AA.pdf?MOD=AJPERES&attachment=false&id=1447702669699

24 PGE: "The charges for the Minimum Bill include components for the generation of electricity and the delivery of energy. The generation portion of the bill is used to pay for the electricity itself, while the delivery portion is used to pay for the transportation of the electricity over PG&E's grid. On March 1, 2016, the Minimum Bill, which previously was applied to the combined total of delivery and generation charges, will now only be applied to the delivery charge." https://www.pge.com/en_US/residential/rate-plans/how-rates-work/rate-changes/minimum-bill-charges/minimum-bill-charges.page

25 SCE: "Standby is a Southern California Edison (SCE) electric rate for accounts with generators that interconnect to and operate in parallel with SCE's electric system. On this rate, we provide back-up electric service when your generator(s) is not operating as intended." https://www.sce.com/wps/wcm/connect/ff018366-cb7a-4441-a7af-e9582ebbf0cd/Standby+FAQ+Sheet+r3_WCAG_K.pdf?MOD=AJPERES&attachment=false&id=1468951849013

26 PGE: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_S%20(Sch).pdf

27 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A5F3592472A270C8525808800517BDD?OpenDocument

28 SDGE: "Solar Customers who are taking service under the Utility's Net Energy Metering tariff are exempt from standby charges. In addition, Solar Customers which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into the Utility's power grid are also exempt from standby charges. Non solar customers taking service under one of SDG&E's Net Energy Metering schedules may be exempt from standby charges pursuant to PU Code Section 2827." http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_S.pdf

29 PGE: "Nonbypassable charges involve costs that were included in bundled service bills and are now separately listed. Customer generation departing load customers may receive bills from PG&E for these charges even when they no longer receive electric service from PG&E. Nonbypassable charges that may apply include the Public Purpose Programs (PPP) and the Nuclear Decommissioning (ND) Charge." https://www.pge.com/en_US/business/services/alternatives-to-pge/departing-load-options/departing-load-options.page

30 CPUC: D. 16-01-044, page 88 "Under [NEM 1.0], NEM customers pay the nonbypassable charges embedded in their volumetric rates. They do so, however, only on the netted-out quantity of energy consumed from the grid, after subtracting any excess energy they supply to the grid. NEM successor tariff customers must pay nonbypassable charges on each kWh of electricity they consume from the grid in each metered interval" http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

31 CPUC: Resolution E-4795 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K911/163911492.PDF

32 CPUC: "A non-coincident demand ("NCD") charge (in $/kW) is assessed on the customer's maximum demand in any 15-minute interval during the billing cycle. A peak-related (or coincident) demand charge ("CD charge") is assessed on the customer's maximum demand in any 15-minute interval during the peak TOU period." http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/SB%20695_Master%20Draft_final_5-12-17.pdf

33 PGE: "To help keep the supply of electricity reliable in California, some time-of-use rate plans, like A10 Time-of-Use, include a Demand Charge to encourage businesses to spread their electricity use throughout the day. This Demand Charge is calculated by using the 15-minute interval during each billing month when your business uses its maximum amount of electricity. As a benefit to this type of rate plan, regular electricity usage charges are approximately 30% lower than for a comparable rate plan without a Demand Charge--giving you the opportunity to save on your bill if you can lower your highest usage 15-minute interval." https://www.pge.com/en_US/business/rate-plans/rate-plans/time-of-use/time-of-use.page

34 OECD: https://stats.oecd.org/glossary/detail.asp?ID=4965

35 CPUC: "Customer-generators with facilities under 1 MW must pay a pre-approved one-time interconnection fee based on each IOU's historic interconnection costs." http://www.cpuc.ca.gov/General.aspx?id=3800

36 Hawaii PUC: page 118 http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464

37 HECO: https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-self-supply-and-grid-supply-programs

Adders

- *Capacity Payments*
  Awarding a customer generator a payment or credit based on load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.[38,39]

- *Locational Adders*
  Awarding a customer generator a payment or credit reflecting the resource's value in certain locations.[40]

- *Environmental Value*
  Awarding the customer generator a payment or credit for benefits based on reductions in the social cost of carbon and/or other environmental metrics.[41]

- *Renewable Energy Credit*
  Awarding the renewable portfolio standard compliance credit to the customer generator rather than the off-taking utility.[42]

- *Market Transition Credit*
  Awarding additional compensation to a customer generator during a defined period of time that recognizes the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified.[43]

- *Price Enrichment Based on Time of Delivery*
  Awarding exports based on the time of delivery, reflecting relative value at different points in time to the distribution system.[44]

- *Grid Services*
  Awarding a customer generator payments for additional services provided to the grid (e.g., voltage support, distribution capacity, and/or reliability/resiliency) as apart of or incremental to self-supply credits.[45]

---

38 CPUC: D. 16-12-036, page 8 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF
39 NY PSC: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument
40 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument
41 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument
42 CPUC: "Renewable Energy Credits (RECs) are among several factors that may affect the economics of solar and other renewable DG facilities, and as such may play an important role in driving the deployment of renewable DG in California and achieving the goals of California Renewables Portfolio (RPS). A REC confers to its holder a claim on the renewable attributes of one unit of energy generated from a renewable resource. A REC consists of the renewable and environmental attributes associated with the production of electricity from a renewable source. RECs are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy." http://www.cpuc.ca.gov/General.aspx?id=5913
43 NY PSC: Cases 15-E-0751 & 15-E-0082 Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A5F3592472A270C8525808800517BDD?OpenDocument
44 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument
45 IDER: http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-1.-Summary-Conclusions-and-Recommendations.pdf

APPENDIX B

SELECTED CUSTOMER GENERATOR COMPENSATION STRUCTURES, PROPOSED AND ADOPTED

	NET METERING	NET BILLING @ EXPORT PRICE	BUY ALL, SELL ALL @ EXPORT PRICE	ANCHORS	ADDERS	NOTES
1	Hawaii Customer Self Supply			Export prohibited + Minimum bill		Driven by DG grid impact; Market slowly adapting
2	CALSEIA			NBC (partial)		
3	SEIA/Vote Solar			Interconnection Charge		
4	Sierra Club @ TOU			TOU		
5	CPUC NEM 2.0 @ TOU			Interconnection + NBC		Up to 7.5% of peak capacity
6	ORA			Installed Capacity Fee (variation on interconnection charge)		
7	NRDC			Demand Charge		
8	Nevada			Excess generation paid share of retail rate declining from 95% to 75% over time		Final policy pending
9	New Hampshire			Excess generation paid share of retail rate (100% T and G; 25% D) + NBCs on gross consumption + monthly true up		No statewide cap; Production meters required
10		Gridworks Option 2 @ loctional value and 3 @ market price		Interconnection + NBC + managed demand charge	Transferrable Credits; temporary Market Transition Credit	
11		New York @ Locational Marginal Price			Capacity Values (wholesale, distribution, targeted distribution) + Environmental Value + Market Transition Credit	Locational differentiation through LMP and distribution capacity
12		PG&E @ Generation Rate		TOU + Demand + NBC + Monthly True-up		
13		Hawaii CGS @ avoided cost (fixed)		Minimum Bill + instantaneous netting + monthly true up		
14		Hawaii Smart Export @ TOD		Minimum Bill + Off Peak Export Uncompensated + Instantaneous netting		Exports at average annual marginal cost of generation
15		SCE @ avoided cost		Grid Charge (Variation on a minimum bill)	REC	
16		SDG&E (Unbundled Rate) @ LMP		System Access Fee (variation on a minimum bill) + PPP + Grid Use Charge + TOU		
17		Arizona @ declining proxy rate		Consumption at specific solar customer charge + Grid Charge + Demand Charge		
18			Maine @ declining discounted retail rate			Rate = 90% of T&D; 100% of G in year one with T&D stepping down 10% each year
19			TURN @ gen + Adder			
20			SDG&E (Sun Credit) @ gen	Stand-by + Interconnection + Monthly True-up		
21			Gridworks Option 4 @ Loctational Value and 5 @ Market Price	Interconnection + NBC + managed demand charge	Transferrable Credits + temporary Market Transition Credit	

Indicates adopted policy

Indicates stakeholder proposal in CPUC R.14-07-002

Indicates options considered in Gridworks' paper, "Sustaining Solar Beyond Net Metering."