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BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002 (Filed July 10, 2014)

PROPOSAL OF THE UTILITY REFORM NETWORK FOR A NET ENERGY METERING SUCCESSOR STANDARD TARIFF

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THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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FOR A NET ENERGY METERING SUCCESSOR STANDARD TARIFF

Pursuant to the Ruling of ALJ Simon on June 4, 2015, Seeking Party Proposals for the Successor Tariff or Contract ("Ruling") (as subsequently modified for scheduling by the June 23, 2015 Assigned Commissioner Ruling), The Utility Reform Network (TURN) hereby submits this proposal for a net metering successor tariff.

I. SUMMARY OF TURN PROPOSAL

TURN proposes that the Commission adopt a Value of Distributed Energy (VODE) tariff as the successor to the current net energy metering (NEM) structure authorized under §2827 of the Public Utilities Code. Under the VODE, customer generators with on onsite renewable distributed energy resource (DER) would be compensated through a two-part retail tariff that charges customers for their total gross consumption based on any applicable retail rate structure and provides offsetting bill credits based on value of onsite renewable generation to the utility and non-participants. Like traditional net metering, the resulting charge/credit will reflect the net benefits provided by total onsite renewable generation.

The VODE tariff delinks compensation from retail rate design and thereby ensures that all customers, including those with distributed resources, have their full usage subjected to the pricing signals embedded in default and optional retail rate designs. This approach avoids the need for new fixed or demand charges or other unique consumption-based rate design elements that could produce unintended consequences by reducing incentives for customers with DER to modify their consumption and behavior patterns.

As part of this proposal, TURN urges the creation of a Distributed Generation Adder (DGA) that would function as a proxy for any additional value needed to satisfy the statutory requirement that the NEM successor tariff ensure "that customer-sited renewable distributed generation continues to grow sustainably". Both the value-based and DGA compensation rates would be fixed for the first 10 years of system operations to offer reasonable certainty for project financing assumptions. After 10 years, the DGA would sunset and participating customers would receive subsequent bill credits based solely upon an annually resetting value-based rate.

This approach is fully consistent with the requirements of §2827.1 of the Public Utilities Code and represents an important step towards accurately valuing onsite generation. The VODE tariff would provide compensation to participating customers based explicitly on the "costs and benefits of the renewable electric generation facility" (as required by §2827.1(b)(3)) and, as a result, the net benefits and costs of the tariff should be "approximately equal" for non-participating customers (as required by §2827.1(b)(4)). TURN's proposal addresses the need for the tariff to ensure that customer-sited renewable distributed generation "continues to grow sustainably" (§2827.1(b)(1)) through the creation of the DGA, a rate mechanism that can be calibrated to achieve a variety of outcomes needed to satisfy this objective. Finally, TURN proposes to support the deployment of renewable DG for residential customers in Disadvantaged Communities (as required by §2827.1(b)(1)) through an upfront financial incentive provided to property owners of low-income housing.

In modeling the results of this proposal, TURN has applied both the bookend cases supplied by the Energy Division and an alternative that reflects TURN's own preferred input assumptions under base and low solar costs. TURN has also modeled a series of sensitivities related to setting the DGA at different levels under each case. These results are provided in Section VII.

There are several practical issues that remain open in this proposal. First, the Commission must decide the minimum level of future renewable DER installations that are necessary to satisfy the sustainable growth criteria in §2827.1. This determination will inform the selection of a DGA under TURN's VODE tariff. Second, the Commission must select the magnitude of the up-front incentive and the structure for delivering the incentive to residential customers in disadvantaged communities.

II. DESCRIPTION OF TURN'S PROPOSED APPROACH

TURN's proposal involves a two-part retail tariff that charges customers for their gross consumption and provides a value-based bill credit for gross production from the renewable energy generator. This approach ensures that customer generators are charged for (and pay) all appropriate retail rates tied to their gross consumption of electricity. Under the VODE tariff, a customer's gross consumption would be billed using the applicable retail rate structure based on the tariff selected from within the options approved for any customer in that class.[1] Customers seeking to host an onsite renewable energy system would not be required to participate in a specific type of retail rate design for purposes of determining the charges on their bill relating to gross consumption. This approach would encourage customers to select the best retail rate option based solely on their overall monthly consumption, load profile, and tolerance for seasonal bill variability.[2] These rate options should continue to be designed to influence retail consumption patterns and fairly collect costs rather than being designed for the purpose of promoting (or frustrating) distributed generation.

[1] This means that residential customers would be billed for their gross consumption based on either the default tiered rate structure or the optional time-variant rates available to any residential customer.

[2] By contrast, the use of retail rates to provide compensation for onsite solar could encourage customers to select the rate structure that is most beneficial for production from their generation unit, and could have the perverse effect of encouraging excess consumption in order to increase generation compensation credit

The customer generator would receive full value for the operation of their onsite renewable generation through a bill credit that would netted against consumption charges. This credit is intended to reflect the value of onsite production to the utility system and non-participants. The value to the host customer would not be determined through the use of retail consumption rates as the determinant of generation value. Details relating to the methodology for calculating this credit are described in subsequent sections of this proposal.

The VODE proposal ensures that participants remain responsible for the full costs to serve their demand and consumption under standard retail rates, and reflects the fact that the utility system is available to serve the customer in the absence of distributed generation. The two-part tariff produces a net bill that fully compensates the customer for the value of the onsite system in the following simplified manner:

NET CUSTOMER BILL =
\+ gross consumption x default or optional rate structure
\- gross production from onsite renewable generation x value of distributed energy compensation rate (including Distributed Generation Adder)

TURN's proposal would allow customers to carry a net credit balance forward on their bills for up to 12 months. These credits could be applied to any net customer bill but would not be eligible for cashing out by the customer. After 12 months, remaining credits would be zeroed out and unavailable for use in a future billing cycle. This approach is intended to be identical to the treatment of excess NEM credits prior to the enactment of AB 920.[3] This treatment ensures that onsite generation is sized to serve customer loads and is not oversized for the purpose of providing surplus generation eligible for compensation under the

[3] AB 920 added §2827(h)(5) which provides for compensation tied to net surplus production over a 12-month period.

VODE.[4] If the Commission concludes that the enactment of AB 327 did not eliminate the requirement to provide net surplus compensation pursuant to §2827(h)(5), TURN recommends that the current formula be retained in order to ensure that the customer retains status as a generator for use under PURPA and federal tax law.

Because the retail rates used to bill customers for consumption are not employed as a proxy to determine compensation for onsite renewable generation under TURN's proposal, there would be no need to establish unique rate design elements (including large fixed, demand or standby charges) for these customers. As a result, the Commission should have confidence that the pricing signals embedded in retail rate design would produce comparable incentives for all customers regardless of whether they have onsite renewable generation.

TURN has used the Public Tool to develop compensation rates under the VODE. These rates take into account the direct benefits provided by onsite generation to all customers as calculated in the public tool. The direct benefits would be provided on a time of use basis. Under TURN's proposal, the direct avoided cost benefits of VODE compensation would be updated annually to reflect a fixed prospective rate for the first 10 years of the life of an onsite generation system.[5]

In addition to the direct avoided cost benefits calculated in the public tool, TURN proposes to include a Distributed Generation Adder (DGA) that would function as a proxy for any additional value needed to satisfy the statutory requirement that the NEM successor tariff "ensures that customer-sited renewable distributed

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[4] TURN's proposal is designed to provide a fair rate structure, consistent with State policy for customers that primarily generate energy for their own use, and for whom excess generation is only incidental to generation for use. Customers choosing to install generation for sale are not meant to be included in this proposal.

[5] This means that any new system installed in a given year would be eligible to receive a fixed compensation rate for the first 10 years.

generation continues to grow sustainably".[6] The DGA is essentially an incentive payment tied to the amounts of renewable distributed generation needed to achieve defined deployment outcomes consistent with adopted public policy.[7]

The DGA should be calibrated to balance the impacts on non-participants with the achievement of Commission-approved targets for the deployment of distributed generation within a defined timeframe.[8] The DGA would be provided as a cents/kwh production incentive. TURN proposes that the DGA be set to ensure a payback of less than 10 years, a Participant Cost Test value greater than 1.0 and a Ratepayer Impact Measure of no less than 0.9. The DGA would only be available for the first 10 years of system operation, after which the customer would continue to receive the annual avoided-cost derived value for production through the life of the system.

The Public Tool can be used to calculate an appropriate DGA using forecasted installations over the identified timeframe using the most recent data on solar costs for the initial year and base case assumptions regarding avoided energy, capacity, distribution, transmission, Renewable Portfolio Standard and Greenhouse Gas (GHG) costs. However, TURN was unable to use the Public Tool to calculate a pure 10-year DGA because the model lacks the functionality to force value-based compensation to terminate after 10 years.

The initial DGA would be provided as a fixed adder (on a cents/kwh basis) to the avoided cost calculation for all production and remain fixed for new installations until defined deployment triggers are achieved, at which point a new DGA would be calculated based on updated forecasts of direct benefits,

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[6] Cal. Pub. Util. Code §2827.1(c)(1).

[7] Because the DGA would be set to promote public policy goals, these costs should be separately identified and recovered as a non-bypassable component of customer rates consistent with the collection of public purpose program costs.

[8] An appropriate target could be based on the Governor's Clean Energy Jobs Plan that calls for 12,000 MW of distributed energy resources to be deployed by 2020.

revised solar costs, tax benefits, the pace of installations, and adopted deployment targets. While the avoided cost portion of the VODE tariff would be recalculated annually (but fixed for 10 years), TURN recommends that the first DGA reset occur based on the cumulative installation of MW blocks with the first reset occurring after 2,000 MW of onsite generation are installed in the service territories of the three Investor-Owned Utilities (IOUs). Reliance on this installation trigger should allow several years to pass prior to any revisions to the DGA being revised. The reset process will allow the Commission to recalibrate the DGA prospectively to ensure that the compensation is sufficient to achieve state goals while not resulting in excessive costs to non-participating customers.

Although both the DGA and direct avoided cost benefits would change over time, both credits would be vintage and fixed over a 10-year period for any new installation. The use of a 10-year timeframe is intended to ensure that there is a predictable revenue stream that allows onsite generation systems to be financeable. This predictability will eliminate any need for the customer or third party vendors to forecast annual changes in VODE compensation to justify the savings forecasted over this period.

After 10 years of production by the onsite system, the DGA would sunset and the VODE would be reset annually for participating customers to properly reflect the direct benefits of the onsite generation.[9] This approach would ensure that the ongoing costs and benefits of the VODE are equivalent after year 10. Starting in year 11, a customer would remain eligible to continue to receive compensation at the annually recalculated avoided cost rate (without the DGA) indefinitely.

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[9] For example, a customer installing a new onsite system in 2020 would receive compensation at the current DGA rate and direct avoided cost benefit rate and fixed for 10 years. Beginning in 2030, the customer would no longer receive the DGA and would be compensated at the new direct avoided cost benefit rate.

III. RATIONALES FOR A VALUE OF DISTRIBUTED ENERGY TARIFF STRUCTURE

TURN believes that the VODE efficiently balances the interests of participants and non-participants while allowing the Commission and other state policymakers to achieve defined long-term goals for the deployment of onsite distributed renewable generation. The two-part value of distributed energy tariff recognizes that cost-based methods can be used to set compensation rates and that cost of service can support consumption charges, while at the same time preserving the character of self-generation primarily "for use" (as opposed to "for sale") on which the net metering model is based. In particular, the VODE tariff is consistent with the following seven key principles that argue in favor of its adoption.

First, the NEM successor tariff should be fair to non-participating customers. Many customers do not have the ability to host or utilize onsite generation and should not be penalized for structural barriers that make installations difficult or impossible.[10] To the maximum extent feasible, and consistent with the direction in §2827.1, non-participating customers should be indifferent to the deployment of distributed generation by participating customers.

Second, the NEM successor tariff should provide fair compensation to the customer generator for the value that their onsite generation brings to the utility system. Value-based analysis can quantify the benefits that distributed solar systems bring to the utility system. TURN's VODE proposal would ensure that the customer generator receives this value in the form of credits to their retail bill.

[10] For example, customers who rent their dwellings are typically unable to install onsite generation. According to the 2010 census, approximately 45% of housing in California is not owner-occupied. Even when housing is owner-occupied, onsite generation can be difficult for customers living in multi-family dwellings or single-family dwellings with extensive shading.

Third, the NEM successor tariff should distinguish value-based compensation from other financial incentives deemed necessary to overcome market failures or achieve defined state policy goals. TURN's VODE tariff would make this distinction through a combination of value-based compensation and a transparent incentive designed to ensure that deployments occur at levels sufficient to achieve public policy outcomes. The incentive would sunset after 10 years, leaving the customer to receive value-based compensation recalculated annually over the remainder of the system life. This approach avoids concerns that legacy projects could receive excessive compensation over the entire life of the system while ensuring that such projects are compensated based on the actual value they continue to provide.

Fourth, the NEM successor tariff should provide the minimum amount of above-market incentives needed to ensure that specific levels of deployment occur to satisfy adopted public policy goals. The VODE tariff is explicitly designed to calibrate incentives to achieve deployment outcomes within defined time frames at least cost.

Fifth, the NEM successor tariff should not frustrate other policy goals such as promoting efficiency and conservation. TURN's VODE tariff concept delinks compensation for onsite generation from retail rate design and thereby ensures that those with onsite generation face the same pricing signals for retail consumption as all other customers.

Sixth, the NEM successor tariff should be sufficiently predictable to allow customers (or third parties) to finance the installation of onsite generation with reliable expectations regarding payback periods and savings. TURN's VODE tariff would provide a locked in compensation rate for the first 10 years of system operation and would be set at levels that yield payback periods of less than 10 years. The promise of predictable bill credits regardless of future changes to retail rate design promotes certainty that should allow for financing on more favorable terms.

Finally, the NEM successor tariff should be intuitively sound and administratively simple to implement and manage. Analytical inputs should be rationally related to the character of solar systems and the quantity and character of energy output associated with the technology. Inputs should also be simply calculated from information the utility already routinely produces.

The cost-based approach represented by the Value of Distributed Energy tariff can be used to align compensation with actual value, minimize market distortions, limit cross-subsidization, and ensure that onsite distributed generation deployments can scale without creating unacceptable costs for non-participating customers.

IV. CONCERNS REGARDING THE USE OF TRADITIONAL NET METERING FOR THE SUCCESSOR TARIFF

The structure of traditional net metering is simple because customers "net" their production of onsite renewable generation against their household energy consumption. This is often described as "spinning the meter backwards"—a nod to the phenomena that local generation can actually cause mechanical meters to spin backwards when generation exceeds consumption in real time. At the time of its introduction, net metering was a major step forward for distributed generation markets because it established a mechanism for compensating retail customers for production from onsite systems that was administratively simple, required few transaction costs, and did not require the calculation of new metrics to determine the appropriate compensation. Traditional net metering also has significant limitations and drawbacks that make it a poor choice for a successor tariff design for at least the following four reasons.

First, although the simple netting of energy consumption and production assigns a retail value to onsite renewable generation, this value may have little relationship to the actual value of incremental renewable generation located on the customer premises. Retail rates are designed to collect a variety of costs, some of which are not avoided through the deployment of customer-side generation. Though convenient, the use of retail rates as a proxy for the value of generation is not based on any solid methodology or empirical approach.

Moreover, a customer taking service under tiered rates receives a different level of compensation for generation production based solely upon the tier of usage. Customers on discounted rates such as CARE would receive a fraction of the bill credit available to a non-CARE customer with usage in the highest tier that can be offset using onsite generation. While TURN believes that tiered rates are appropriate for incentivizing changes to customer behavior, there is no similar rationale that supports different levels of compensation for onsite generation.

Second, the traditional net metering approach fails to protect non-participating customers against cost shifting. A customer with onsite generation could offset most or all utility charges (except for the minimum bill) even though they continue to require electric service at night, during early evening distribution circuit peaks, and on an as-needed basis over the electric distribution network. The resulting potential misalignment in cost responsibility for these participating customers means that other utility customers could be required to pay some of these avoided retail costs. While tying distributed generation compensation to retail rates was appropriate at relatively low market penetration rates, this approach no longer makes sense given the precipitous drop in solar and other distributed generation costs. Moreover, the use of a retail rate credit cannot be scaled up to support far higher levels of onsite distributed energy deployment without creating a risk of significant and unacceptable amounts of cross-subsidization.

Third, traditional net metering can distort and undermine retail rate incentives that seek to encourage customers to lower their usage, shift their demand, and invest in efficiency and conservation. For a customer served under a tiered rate, onsite generation is credited at the marginal tier price and may result in incremental usage being charged at a lower marginal rate. With remaining usage being billed at lower rates, the customer has fewer incentives for conservation and efficiency. Any customer with sufficient distributed generation production to trigger a minimum bill would be further incentivized to increase their monthly usage up to the level of the minimum bill since this incremental consumption is effectively priced at zero. Net metering therefore can work at cross-purposes with the goal of maximizing energy efficiency and conservation for distributed generation customers.

This perverse incentive also occurs in the event that the customer produces excess energy over the course of a 12-month period. Under this situation, the net surplus production is eligible for compensation based on the value of the electricity and the value of any renewable attributes provided to the utility.[11] Because the avoided cost approach for valuing net surplus production is far lower than rates charged for retail consumption, a customer with excess annual production is motivated to increase overall usage given the relatively minimal incremental costs. This customer also faces very severe disincentives to invest in energy efficiency or conservation since the value of any reductions in usage would effectively be valued at the low net surplus compensation rate.

[11] Cal. Pub. Util. Code §2827(h)(5).

Fourth, traditional net metering does not provide sufficient predictability regarding compensation over the first 10 years of system operations and therefore undermines the goal of promoting the financeability of new onsite generation. It is not possible to predict with any degree of accuracy future changes to average retail rates or the rate structure itself. Future actions by the Commission or Legislature can significantly impact the design and overall level of retail rates. For example, a residential customer may be subject to a future fixed customer charge of unknown magnitude, changes in TOU rate periods, adjustments to inclining block tier ratios, and other unforeseeable changes that will effect the value of onsite generation if compensation is tied to retail rate design. This uncertainty makes it harder to justify investments in new systems unless the near-term savings appear large and expected payback periods are short. The result is that retail NEM effectively requires retail rates to provide a healthy margin over system costs in order to induce customer investments in new onsite generation. This healthy margin is unnecessary once system payback has occurred but, under net metering, remains in place for the life of the system.

Finally, the changing usage profile of a customer over time can effect the compensation received under a NEM structure. Under a tiered rate structure, a customer would anticipate receiving compensation based on the marginal tier price. If the customer undertakes energy efficiency or conservation measures, more production from onsite generation could end up being compensated at a lower tier price. This makes it challenging to accurately forecast the actual bill impacts of onsite renewable energy production under net metering.

V. TURN'S PROPOSAL IS CONSISTENT WITH STATE AND FEDERAL LAW

The proposal for a VODE tariff as a successor to the current net metering approach is consistent with the new requirements enacted in AB 327 that govern the “standard contract or tariff” available to new customers no later than July 1, 2017. These requirements are found in §2827.1 of the Public Utilities Code and apply to the successor tariff “notwithstanding any other law”. TURN was actively involved in negotiations over this portion of AB 327 and believes that the VODE tariff fits squarely within the requirements laid out in this section.

A. Alignment between TURN’s VODE Tariff and §2827.1

Consistent with the language in §2827.1(a) and (b), TURN’s proposal is a “standard tariff” that would be available to any customer that meets the requirements of “eligible customer-generator” as defined in §2827(b)(4). Eligibility would be limited to customers with onsite renewable generation sized to offset part or all of the customer-generator’s annual electrical consumption. The other requirements of §2827.1 are discussed in the following sections.

1. Ensuring that customer-sited renewable distributed generation continues to grow sustainably

In enacting AB 327, the Legislature intended for the Commission to reduce the embedded subsidies in current NEM through the development of a successor tariff that more explicitly balances non-participant costs and benefits. But the Legislature also clearly wanted to ensure that bringing compensation rates more in line with the costs and benefits of the distributed energy generation. The VODE tariff is balanced with the desire to allow the recent boom in distributed generation to continue.

TURN does not believe that Public Utilities Code §2827.1(b)(1) requires the Commission to adopt any particular quantitative methodology for determining whether a successor tariff would permit “sustainable growth” of renewable distributed generation. However, TURN recognizes that the purpose of this paragraph is to “ensure” meaningful progress in the coming years. At the time of this filing, the three IOUs reported 3175.6 MW of net metered capacity installed on their system since 1996 or awaiting installation and in the queue.[12] The pace of installations has grown in recent years with annual installations forecasted to exceed 800 MW in 2015 and 2016.[13] Just maintaining this pace between 2017 and 2025 (the period shown in the Public Tool) would result in more than 7,000 MW of additional installations. In TURN's view, an outcome that leads to installed capacity increasing from approximately 5,000 MW to over 12,000 MW between 2017 and 2025 should be understood to satisfy "sustainable growth" in customer side renewable distributed generation.

TURN believes that §2827.1(b)(1) provides the Commission with some degree of flexibility to augment the purely mechanical exercise in balancing these costs and benefits with additional incentives designed to "ensure" the achievement of identified targets for additional customer-side installations over a defined time period. TURN's proposal incorporates a Distributed Generation Adder (DGA) intended to provide a fixed level of additional compensation to the customer-generator for the first 10 years of project life. The DGA is designed to bridge the gap between the value of distributed renewable energy, on a cost basis, and the level of compensation needed to allow "sustainable growth" in distributed renewable generation. Because the DGA would be fixed for a 10-year period (as would the value-based portion of the compensation), customers could rely on the predictability of this revenue stream to finance and develop new distributed renewable generation projects.

TURN is not proposing to select a particular installation target through 2025 but is proposing certain criteria and processes to guide the initial calculation of the DGA and subsequent revisions. First, TURN believes that the DGA should be set to ensure an implied payback period of less than 10 years. Because the DGA itself

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[12] According to the latest monthly reports, PG&E has 1549.5 MW, SCE has 1204.1 MW, and SDG&E has 422 MW.
[13] Energy Division staff report, page 1-29.

would sunset after year 10, the payback period should not extend beyond the duration of the DGA itself. Second, the DGA would be set in combination with the value-based compensation, to ensure a RIM ratio of at least 0.9 and a PCT ratio of at least 1.0. These constraints represent an effort to balance the goal of "sustainable growth" with the goal of minimizing cost impacts for non-participants. Moreover, they are consistent with the Energy Division staff repor that identifies these same factors – adoption rates and PCT/RIM ratios, as the proper way to balance the competing objectives of the statute.[14]

To ensure that the DGA can be used to achieve these goals over time, TURN recommends that the level be reset (for new customers) after defined installation triggers have been met. TURN suggests that the first trigger should be tied to 2,000 MW of new installations, at which time the DGA would reset to a new level designed to balance adoption rates with costs to non-participants. This ongoing process of recalibration would help to minimize the amount of subsidies required to satisfy the "sustainable growth" goal and should ultimately allow for a successor tariff that achieves indifference for utilities and non-participants.

2. *Ensuring that the successor tariff is "based on the costs and benefits of the renewable electrical generation facility."*

The development of a VODE tariff is explicitly intended to link compensation to the "costs and benefits" of distributed renewable generation and not to the ongoing evolution of retail rate design. TURN's proposal represents a shift to value-based compensation calculated based on avoided costs and net benefits to the utility system. This approach, described in detail in Sections V and VI, represents a true cost and value-based tariff.

The only portion of TURN's proposal not tied to avoided costs and net benefits is the DGA described in the previous section. But the DGA is an incentive payment

[14] ED Staff Report, pages 1-24, 1-25.

that should be set at the minimum level necessary, based on the expected costs of future installations, to ensure specified levels of adoption over time. Because the DGA is fully transparent and not baked into the value-based component of compensation, the VODE constitutes a hybrid approach compensates the customer "based" on costs and benefits of production while also providing additional incentives tied to the "costs" of developing financeable new projects.

TURN proposes that the value-based compensation element be fixed for the first 10 years of system operations to provide a predictable revenue stream based on anticipated production. The fixed compensation, which would be time differentiated, should be calculated as a levelized 10-year value that reflects the Public Tool forecast of the avoided costs and net benefits to be realized over this period. Over this same period, the DGA would be fixed. Beginning in year 11, the DGA would sunset and prospective compensation would be based exclusively upon an annually determined value-based payment that would precisely reflect avoided costs and net benefits.

The VODE represents the most cost-based approach to compensation amongst the options that can be modeled with the Public Tool. Compared to alternative approaches that rely on retail rates as the basis for bill credits, the VODE tariff offers a superior approach to satisfying the requirement by being based specifically on costs and benefits.

3. Ensuring that the "total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs."

TURN's two-part VODE tariff is designed to align the costs and benefits of the program to all customers and thereby achieve non-participant indifference to the maximum extent feasible. The primary measure of indifference in the Public Tool is the RIM test. While TURN would prefer that the VODE tariff result in a RIM that exceeds 1.0, the need for a DGA to satisfy the statutory requirement for "sustainable growth" means that such an outcome is difficult to achieve unless distributed generation and solar costs are below the base case assumptions. In an effort to solve for both non-participant indifference and sustainable growth, TURN proposes that the final tariff result in a RIM that exceeds 0.9. While this ratio would not satisfy a strict indifference test, it does represent "approximate" indifference for purposes of implementing the successor tariff.

Moreover, the Public Tool does not adequately show the extent to which the VODE tariff would produce long-term non-participant indifference. After the first 10 years, participants would receive value-based compensation reassessed annually. The calculation of "value" would be limited to the same avoided cost factors that TURN relies upon in its Public Tool scenario. Because compensation after year 10 would more precisely align costs and benefits, the VODE tariff is designed to avoid a situation in which cost shifting becomes more pronounced over time. Once the DGA sunsets, customers with distributed generation would receive fair value and non-participants should be indifferent to the continued operation of these units.

Furthermore, the VODE tariff methodology can be refined over time so that prospective compensation rates properly reflect the latest information and analysis on the costs and benefits of distributed generation to the electric system. This means that the approach is flexible and can adapt, over time, to incorporate new data and changing system conditions. This flexibility should allow the Commission to monitor the relationship between costs and benefits and make mid-course adjustments as needed to achieve "approximate" non-participant indifference.

B. Other Legal Issues

1. Compliance with the Public Utility Regulatory Policies Act

TURN's VODE tariff proposal retains the structure and approach that is the basis for net metering's exemption from regulation under the Public Utility Regulatory Policies Act (PURPA). The change in the compensation rate applied to the gross production billing determinant under the VODE tariff does not change the net billing arrangement that exists under the current net metering model and therefore does not create a "sale" that would be treated by FERC as a wholesale transaction subject to avoided cost pricing.

In rejecting a challenge to net metering by MidAmerican Energy, FERC concluded "no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting."[15] FERC has reaffirmed this holding in subsequent decisions, and state commissions have relied upon these precedents to design net metering tariffs that provide retail rate credits for production during a billing period.[16] The Commission previously agreed that "FERC has held that a net billing arrangement is not subject to FERC jurisdiction so long as no "net sale" is made to the utility."[17]

Under existing NEM, excess credits accumulated over a billing period may not be paid out to a customer in cash. California allows NEM customers to carry forward any surplus balance for 12 calendar months. Any credit balances that remain after 12 months are zeroed out if there is no excess production on a kWh basis.[18] If the customer has net surplus production (on a kWh basis) over a 12-

[15] Midwestern Energy Co., 94 FERC ¶61, 340 (2001)
[16] Sun Edison LLC, 129 FERC ¶61, 146 (2009).
[17] D.11-06-016, page 9.
[18] Many existing NEM customers have surplus bill credits that are not attributable to excess production over a 12-month period. This is due to the fact that customers on time of use rates

month period, they are eligible for compensation based on the value of the electricity and the value of any renewable attributes provided to the utility.[19] This approach, authorized by AB 920 (Huffman, 2009) is consistent with the PURPA requirements governing the pricing of energy purchased from cogenerators and other "qualified facilities."

TURN proposes that the treatment of surplus production under the VODE tariff be identical to the treatment under current NEM. Any net surplus production over a 12-month calendar period should remain subject to the treatment required under AB 920. This treatment ensures that customers with DER taking advantage of the successor tariff will calibrate the size of onsite facilities so as not to exceed the annual consumption by the customer.

2. *Tax Implications for Participating Customers*

The federal Internal Revenue Service primarily distinguishes solar energy generation as "generation for use," or "generation for sale." The change in the compensation rate applied to the gross production billing determinant under the VODE does not change the net billing arrangement that exists under today's net metering model, and therefore, does not create a "sale." There is no reason to believe that credits applied to the customer bill would receive differential tax treatment based solely upon the valuation approach selected by the Commission. To the extent that customers are not engaging in net sales of energy, there should be no taxable obligation. In attachment 2, TURN provides a detailed policy and technical review of tax issues related to a Value of Solar tariff authored by Karl R. Rábago, the Executive Director at the Pace Energy and Climate Center.[20]

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receive bill credits based on the timing of solar production exported to the grid. Excess production during peak periods can generate bill credits that exceed the rate charges for consumption of a similar quantity of energy during off-peak hours.

[19] Cal. Pub. Util. Code §2827(h)(5).

[20] Attachment 2, *A Policy and Technical Review of Tax Issues and Distributed Solar Tariffs.*

VI. DESCRIPTION OF TURN'S PROPOSAL

A. Description & Evaluation of Proposal

The VODE tariff has been described in previous sections of this pleading. TURN proposes this two-part standard tariff available to all eligible customer-generators as a method of separating gross generation and gross consumption for separate presentation on the bill and applying separate rates for each billing determinant. The two-part rate structure, which credits all generation at the VODE rate and charges for all consumption at the otherwise applicable retail rate, aligns customer value with energy efficiency policy objectives and allows tiered rates or other rate designs to continue to work effectively.

The two-part rate allows consumption to be accurately and fully billed according to approved rates. There is no need for a separate or unique rate for gross consumption and no limitation on the participating customer's ability to select any approved consumption rate structure. The second part of the tariff credits the customer for gross production by the onsite distributed energy resource using both a value-based calculation and a distributed generation adder. These two parts would be shown on the customer bill and netted against each other on a monthly basis as follows:

Participating customer bill
(Gross consumption x applicable retail rate)
– (DER gross production x value-based calculation)
– (DER gross production x distributed generation adder)

Under this approach, gross production and gross consumption are measured on a monthly basis. Any net charges for the billing cycle are paid by the customer and any excess credits are carried forward for up to one year. At the end of the yearly period, the customer could be compensated for any net surplus production based on the existing formula under §2827(h).[21]

The value-based rate for gross production would be developed based on the following parameters:

- Calculated based on a levelized 10-year forecast of avoided costs using the inputs described in Section VII.[22] Value-based compensation is recalculated annually and vintaged for new customers.

- Fixed for the first 10 years that a customer remains on the VODE tariff. Floats and resets annually beginning year 11.

- Provided on a time-differentiated basis to reflect changes in value by hour and season.

The Distributed Generation Adder (DGA) for gross production would be developed based on the following parameters:

- Calculated to ensure that total compensation for gross production, in combination with the value-based rate, is sufficient to justify the installation of a defined quantity of new distributed renewable generation over a 10-year period. This defined quantity should be tied to Commission

[21] The formula is tied to the average weighted Default Load Aggregation Point (DLAP) price for each electric utility. The Commission already publishes the average net surplus compensation rates on its website (http://www.cpuc.ca.gov/PUC/energy/DistGen/netmetering.htm).
[22] These include avoided RPS and conventional energy procurement, avoided generation capacity and some credit for marginal avoided transmission, subtransmission and distribution costs. TURN also assumes that Renewable Portfolio Standard (RPS) requirements increase from 33% in 2020 to 50% by 2030. Distributed Renewable Energy Resources located behind the customer meter are used to reduce retail sales under the RPS and do not count as a Product Content Category 1 procurement resource.

findings regarding the minimum pace of installations needed to satisfy the "sustainable growth" standard.

• Calibrated to ensure an implied payback of less than 10 years for new installations, a Participant Cost Test value greater than 1.0 and a Ratepayer Impact Measure of no less than 0.9.

• Initial DGA is available to the first 2,000 MW of installations and is recalculated for the next tranche of installations. Customers keep the DGA in place at the time of initial subscription (vintaged).

• Provided as a flat cents/kWh production incentive (not time differentiated)

• Fixed for the first 10 years that a customer remains on the VODE tariff, sunsets at the end of year 10, and may not be extended or renewed.

• Costs of the DGA should be recovered from all ratepayers and treated as a public purpose program cost for purposes of inter-class allocation.

TURN's modeling of this proposal is shown in Section VI and evaluates results under both bookend cases provided by the Energy Division and one alternative case that represent TURN's preferred input assumptions. In each case, TURN offers a range of DGA levels that illustrate the potential impacts on new installations and benefit cost ratios for both participants and non-participants.

B. Treatment of systems sized larger than 1 MW

Pursuant to AB 327, the successor tariff shall allow projects larger than 1 MW to be built to the size of onsite loads so long as there is no significant impact on the distribution grid.[23] TURN has not proposed any differential treatment of systems larger than 1 MW under the VODE tariff.

As a general matter, these customers would be treated identically to those with smaller systems. However, TURN recognizes that larger projects will be less costly (on a $/watt basis) than smaller projects. As a result, it would be appropriate to retain the same value-based rate for gross production but calculate a different DGA for projects at this size level. Since the DGA is explicitly calculated based on anticipated solar installation costs, and is very sensitive to this assumption, the DGA level could be set at different levels for various project sizes. This approach would ensure that only the minimum DGA level needed to achieve the four evaluation criteria (minimum installations to achieve sustainable growth, payback period < 10 years, PCT ≥ 1, RIM ≥ 0.9) is authorized. Setting a separate DGA for these large systems is consistent with the statutory requirement to ensure that the costs and benefits of the successor tariff are "approximately equal".

C. Applicability to current variations of NEM

TURN does not anticipate that the VODE tariff would require any specific adjustments to accommodate virtual net metering or aggregation arrangements. Participant accounts would be billed for their gross consumption at the applicable retail rate and receive bill credits based on their pre-authorized share of the gross output of the generation. This approach greatly simplifies the process of providing bill credits for projects under either arrangement. The VODE tariff should provide certainty of compensation over a 10-year period and the DGA could be additionally calibrated to address any public policy goals relating to unique barriers at multi-unit properties.

[23] §2827.1(b)(5).

TURN does not believe that systems located on the utility side of the meter should be eligible for the VODE tariff under a virtual net metering or aggregation arrangement. Moreover, TURN does not support providing bill credits to a customer not located on the same property as the distributed generation system. This type of expansion is not contemplated under §2827.1 and would require a different mechanism and valuation approach.

D. Treatment of interconnection costs, standby charges, and non-bypassable charges

TURN's proposal does not contemplate any special or additional exemptions from interconnection application and study fees and distribution upgrade fees. The policy, economic, and technical justifications for such exemptions are not necessarily impacted by the use of the VODE tariff. As noted above, however, application of the rate to certain virtual and aggregated net metering systems located on properties with greater barriers (like multi-unit housing) could provide a basis for a policy decision to grant special fee exemptions.

For example, fee exemptions could be used as an added incentive to developers to identify high value aggregated net metering sites in economically and environmentally disadvantaged community locations. TURN has not developed a specific proposal for situations in which interconnection costs would be waived but believes this is worth additional review if the Commission adopts the basic VODE tariff structure.

TURN is not proposing any changes to rates to account for standby charges or the collection of non-bypassable charges. These costs, to the extent included in retail rates, would be fully collected from all participating customers under the VODE tariff because they are embedded into the relevant consumption rates. Participating customers would remain responsible for their share of such costs to the extent applicable.

E. <u>Safety issues</u>

TURN has not proposed any particular elements that address safety issues but will review proposals made by other parties to determine whether particular safety elements are appropriate. To the extent that any reasonable new safety requirements create incremental costs, such costs should be the responsibility of the solar customer generator.

F. <u>Consumer protection issues</u>

TURN believes that the Commission should condition eligibility for the NEM successor tariff on a demonstration that any vendor selling an onsite system to a customer has complied with a series of particular disclosure requirements. These requirements should ensure that customers receive accurate information before committing to acquire an onsite solar system or enter into a long-term contract with a third-party provider in the form of a lease or a Power Purchase Agreement (PPA). The Commission should consider requiring certain standardized assumptions and disclosures by any third party seeking to sell or lease a renewable generation system or proposing a PPA that is eligible for the NEM successor tariff. TURN suggests that the following items be included in the standardized assumptions:

<u>Projections of expected savings</u>

The Commission should establish a standard methodology for any presentation of expected savings in order to prevent vendors and installers from offering projections that are inaccurate or cannot be reasonably compared amongst options being considered by potential customers. Ideally, the Commission would provide this functionality on its own website. Alternatively, the Commission could direct each IOU to make such a calculator available for customers to use in estimating the expected credits to their bills over time. While TURN recognizes that savings beyond year 10 of the tariff (when the DGA sunsets) may be more challenging to predict with accuracy, there is a great need for standard approaches to allow customers to fairly compare various offers provided by competing vendors.

Uniform disclosure of all contract costs over time

Many third parties offering leasing or PPA arrangements include annual price escalators. A potential customer should be informed of the price to be charged in each year of the contract rather than simply provided the cost or price in the first year of the agreement with a reference to annual escalation. TURN is concerned that these escalators are buried within the estimates of net savings provided by vendors and are not easily understood. Since the VODE tariff would provide a predictable compensation rate over the first 10 years of system operations, any third party arrangements should specify how the year-by-year costs compare to expected compensation over the term of the agreement.

Clear and understandable disclosures related to sale of the property

Customers entering into leases or PPAs who sell their home prior to the end of the agreement may be responsible for a balloon payment in the event that the new owner is unable or unwilling to assume the remaining obligations. There should be standard disclosures that clearly identify customer responsibility for unpaid obligations at the end of each year of a proposed agreement. This would assist customers in assessing their potential financial obligations if they leave their home and are unable to find a new owner who can or will assume the contract.

Clear and understandable disclosures related to treatment of RECs

Third-party vendors and leasing agents should be required to provide more comprehensible disclosures relating to the treatment of Renewable Energy Credits (RECs) and the consequences of specific contract provisions for NEM customers. There is little evidence that customers have any comprehension of this issue or the obligations they assume if they do not retain their RECs. Third parties offering leases or PPAs typically retain the right to certify and sell these RECs.

Under current law, RECs associated with production at a customer's property may be sold to another entity for use in voluntary "green" programs or compliance with Renewable Portfolio Standard (RPS) obligations. If the arrangement does not allocate the right to these RECs to the customer, there should be express notification that the customer may not publicly claim that they are receiving renewable energy. Claims regarding the "renewable" attribute should be limited to the owner of the associated RECs.[24] It would be impermissible double counting in the event that a customer claims that they are receiving renewable energy and another entity (such as an Electric Service Provider or Publicly Owned Utility) makes the same claim for the RECs associated with the same output from the same generation facility. This is particularly important to for-profit businesses subject to Federal Trade Commission jurisdiction.

VII. MODELING THE POTENTIAL TARIFFS RESULTING FROM TURN'S VODE PROPOSAL

The following includes an identification and discussion of the results of TURN's compensation proposal ('Value Based Compensation' selected in the 'Compensation Structure' field on the 'Basic Rate Inputs' tab) overlaid on the two Energy Division bookend cases, as well as, a third case, which consists of TURN's perspective on key drivers, such as anticipated future RPS requirements, avoided costs, Distributed Energy Resource costs, and discount rate

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[24] This extends to any entity with the right to claim such RECs even if the system is not registered with the regional tracking system and the credits are not actually certified for use or sale.

environments. Given uncertainties regarding the true trajectory of solar costs, TURN ran its policy proposal twice to illustrate its performance under two different cost-trajectory assumptions. The first involves a base-case solar cost trajectory, and the other uses a low-case solar cost trajectory. These two sensitivities form bookends relating to TURN's policy and avoided cost assumptions and yield somewhat different results from overlaying TURN's compensation structure over ED's bookend cases.

Under TURN's VODE tariff the compensation levels, payback periods and benefit ratios do not vary depending upon which retail rate design is selected in the model. This outcome is expected given that the VODE proposal compensates DER owners on the basis of the value of production from onsite generation regardless of the retail consumption rate selected by the customer. TURN therefore presents only one set of results for each of the cases described above and does not offer separate results based on each of the rate design options described in July 20, 2015 ALJ Ruling.

TURN notes that the Public Tool is not designed to model several key elements of the VODE. Specifically, the Public Tool is not configured calculate a pure 10-year DGA because the model lacks the functionality to force value-based compensation to terminate after 10 years. Also, the Public Tool does not allow for the modeling of a fixed value-based compensation rate for the first 10 years followed by a floating rate beginning in year 11. The results of TURN's modeling should therefore be considered to be illustrative and would require further modifications to the Public Tool to set rates based on the actual design of the VODE (including the 10-year DGA).

A. Model Results

A summary of the modeling results from TURN's scenarios is presented in Table 1 below. Each case is presented with a sensitivity analysis tied to assumptions for four different DGA levels. These four DGA levels are shown to illustrate the potential adoption rates and benefit-cost ratios for both participants and non-participants. This presentation is intended to show the Commission that TURN's basic proposal can be adjusted through different DGA levels to achieve a desired installation level, cost-benefit ratio, or payback period. The four DGA levels are shown under TURN's assumptions using both a base case carbon/base-case solar cost trajectories and a base case carbon/ low case solar-cost trajectory.

Table 1: Sensitivity-Analysis Results of TURN's Policy Proposal

Scenarios	Total DER Adoptions	Forecasted Installations Post 2016 (MW)	Average Implied Payback (years)	Average PCT	Average RIM (All Gen)	Constant Compensation (c/kWh) by Utility and Climate Zone Example[1]		
						Constant Compensation PGE (Zone PS)	Constant Compensation SCE (Zone 56)	Constant Compensation SDGE (Zone 1)
Low bookend Case w/ Value-Based Compensation								
DGA $.00/kWh	1,421,037	2,194	20.10	0.49	0.928	8.83	8.95	8.87
DGA $.03/kWh	1,484,402	2,251	14.91	0.66	0.670	12.38	12.52	12.43
DGA $.06/kWh	1,649,545	2,491	11.84	0.83	0.554	15.91	16.05	15.96
DGA $.10/kWh	2,100,366	4,059	9.60	1.02	0.504	20.56	20.71	20.60
High Bookend Case w/ Value-Based Compensation								
DGA $.00/kWh	2,564,290	10,937	7.40	1.33	0.905	10.38	11.02	10.40
DGA $.03/kWh	2,951,093	13,861	6.19	1.59	0.715	13.05	13.70	13.05
DGA $.06/kWh	3,158,262	15,362	5.27	1.86	0.583	16.16	16.82	16.16
DGA $.10/kWh	3,317,719	16,505	4.35	2.26	0.464	20.55	21.23	20.55
TURN Assumptions w/ Base Solar Cost Value								
DGA $.00	1,416,381	2,567	9.91	1.08	1.202	9.96	10.43	9.90
DGA $.03	1,858,427	5,345	9.17	1.16	1.046	13.57	14.05	13.51
DGA $.06	2,246,778	8,124	8.57	1.25	0.916	17.02	17.48	16.92
DGA $.10	2,641,379	11,214	7.76	1.38	0.768	21.27	21.73	21.16
TURN Assumptions, w/ Low Solar Cost Value								
DGA $.00/kWh	2,369,961	9,119	8.40	1.27	1.214	9.58	10.02	9.48
DGA $.03/kWh	2,749,951	12,106	7.52	1.42	1.026	12.40	12.84	12.29
DGA $.06/kWh	2,999,146	14,029	6.59	1.62	0.866	15.11	15.57	15.02
DGA $.10/kWh	3,196,863	15,552	5.51	1.94	0.691	19.04	19.51	18.95

[1] The constant-compensation values provided here are the weighted average TOU rate and are for comparison purposes, only. The actual model run was done using TOU compensation.

NOTE: the DGA values are incorporated into the model as societal values of avoided cost not as adders to the compensation rate. Therefore, the amount of the DGA is not strictly reflected in the difference in rates for any given DGA values.

Table 1 illustrates the critical impact of the underlying policy and avoided-cost assumptions on results. Under the TURN VODE with no DGA, the implied payback period ranges from 7.4 years under the high bookend case to 20.1 years under the low bookend case with Participant Cost Test (PCT) ratios ranging from 1.33 under the high bookend case to 0.49 under the low bookend case.

A review of the TURN scenarios that differ only by the choice of either base-case and low-case solar trajectory assumptions highlights the critical role that solar costs have on expected installations and benefit cost ratios for participants. While the compensation rates under the TURN assumptions using base-case and low-case solar costs are similar (especially for the sensitivity where the DGA equals zero), forecasted installations differ significantly. The case with a base-cost trajectory yields 1.4 million adoptions and 2,567 MW of capacity whereas the case with a low-cost trajectory yields 2.4 million adoptions and 9,119 MW of capacity.[25] This is further evidence that much of the expected adoption results hinge on variables (e.g. the cost of solar installation and maintenance) over which neither the Commission nor the utilities have any control. This high level of sensitivity argues in favor TURN's proposal to reset the DGA after the first 2,000 MW of installations. This approach allows the Commission to respond to actual changes in solar costs over time through changes to the DGA.

The results in Table 1 are intended to provide the range of results possible under various policy and avoided-cost assumptions along with a variety of DGA alternatives. If the Commission adopts a value-based compensation tariff that includes a VGA and meets the minimum criteria for the PCT and RIM suggested by TURN (PCT ≥ 1.0 and RIM ≥ 0.9), TURN's value-based compensation proposal with a DGA of no more than 6 cents/kWh would be appropriate as an initial tariff. Under a base solar cost trajectory, the 6 cents/kWh DGA yields a PCT of 1.25 and a RIM of 0.905 with expected installations of 8,124 MW. If solar were to follow the low-cost trajectory, the PCT and installations (1.62 and 14,029 MW) are more robust. In this case, the Commission could adjust the DGA downward after the first 2,000 MW to ensure that the RIM remains above the 0.9 threshold.

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[25] This result occurs even though compensation rates for the low solar cost trajectory are lower than they are for the base solar cost trajectory. The fact that compensation rates differ under these two scenarios is not a feature of TURN's proposal but a result produced by the Public Tool. It is not obvious to TURN why the choice of solar costs yields different compensation values that are tied to avoided cost inputs.

B. Identification and Discussion of TURN's Modeling Inputs

TURN's input selections are shown on Table 2 (see next page) along with the bookend-case inputs provided by the Energy Division. In the following sections, TURN discusses the rationale for the inputs assumed in the TURN scenario.

Table 2: Summary of Input Selections for ED's Bookend Cases and TURN's Proposal

	Bookend Cases (with Value-Based Compensation Selected)		**TURN Proposal (with Value-Based Compensation Selected)**
	High Bookend	**Low Bookend**	**High Renewable DG Value Cas**
Policy Inputs			
2030 RPS Target	33% RPS from Utility-Scale Renewables	50% RPS from Utility-Scale Renewables	**50%** RPS from Utility-Scale Renewables
Marg. Gen Capacity Avoided Cost Treatment	Renewable DG Generation is vintaged	Renewable DG Generation is NOT vintaged	Renewable DG Generation is **vintaged**
EV Penetration & Charging Scenario	Base EV Penetration (4.227 million EVs and 2.528 million fuel cell vehicles in 2030). More daytime charging (35% of all EV charging occurs between 9am-4pm).	Base EV Penetration (4.227 million EVs and 2.528 million fuel cell vehicles in 2030). Less daytime charging (10% of all EV charging occurs between 9am-4pm).	Base EV Penetration (4.227 million EVs and 2.528 million fuel cell vehicles in 2030). **Less** daytime charging (10% of all EV charging occurs between 9am-4pm).
ZNE Homes	ZNE Not Implemented	ZNE implemented: All new residential homes have solar starting in 2020 (approx. 410 MW per year)	ZNE **Not** Implemented
REC Scenario	NEM Reduces RPS via bundled sales	NEM Reduces RPS via bundled sales	NEM Reduces RPS via bundled sales
Avoided Cost Inputs			
Natural Gas Price	Default Value	Default Value	Default Value
RPS Power Puchase Agreement Costs	Default Value	Default Value	Default Value
Carbon Market Costs	High Value	Base value	**Base** Value
Resource Balance year	2017	Model will calculate	**2017**
Anicllary Service Costs	1% of Market Energy Purchases	1% of Market Energy Purchases	1% of Market Energy Purchases
Marg. Avoided Trans. Costs	No Value	No Value	**$12.50/kW-yr.**
Marg. Avoided Energy Cost Locational Multiplier	100%	100%	100%
Marg. Avoided Subtrans. Costs	100% (In $2011, PG&E: $19.29/kW-year; SCE: $23.29/kW-year; SDG&E: NA)	No Value	100% (In $2011, PG&E: $19.29/kW-year; SCE: $23.29/kW-year; SDG&E: NA)
Marg. Avoided Dist. Costs	100% (In $2011, ~ $45/kW-year)	No Value	**65% (In $2011, ~ $45/kW-year)**
Utility Distribution Capital Expenses			
PG&E, SCE, SDG&E	Default Value (100%)	Default Value (100%)	Default Value (100%)
DER Costs			
Solar Cost Case	Low Cost	High Cost	**Base** and **Low** Cost[1]
Successor Tariff/Contract Program Costs Paid By	All Customers	All Customers	All Customers
Utility Rate Escalation Assump.	5%	5%	**N/A when using the Value-Based Consumption structure**
Compensation Tax Treatment	Tax Exempt	Tax Exempt	Tax Exempt
Societal Inputs	**None**	**None**	**None**
Discount Rate Inputes			
Part. Discount Rate	9%	9%	**8%**
Utility Discount Rate	7%	7%	**8%**
Societal Discount Rate	5%	5%	5%
Inflation Rate	2%	2%	2%

1. *Policy Inputs*

a) <u>2030 Renewable Portfolio Standard (RPS) Policy Target</u>

The Energy Division used 2030 RPS targets of 50% in the low bookend case and 33%in the high bookend. TURN recommends that the Commission assume a 50% RPS target for purposes of this analysis. In his inaugural address to the Legislature earlier this year, Governor Brown called for the state to "increase from one-third to 50 percent our electricity derived from renewable sources" by 2030.[26] Consistent with this goal, the Legislature is actively considering several major bills to expand the RPS program to 50% by 2030.[27] Moreover, the Legislature already provided the Commission with authority in AB 327 to increase the RPS target for all retail sellers beyond the 33% cap that was previously in state law. Given the wide support for a 50% RPS target by 2030 by an array of elected officials and stakeholders, TURN believes it is appropriate include this assumption in the Public Tool for purposes of modeling the successor tariff.

b) <u>Marginal Generation Capacity Avoided Cost Treatment</u>

The Energy Division includes Non-Vintaged and Vintaged selections for Marginal Generation Capacity Avoided Cost Treatment for the low and high adoption cases. TURN recommends that the Commission use Vintaged as the assumption for marginal Generation Capacity Avoided Cost. As noted by the Energy Division, the ability of a DER system to reduce net load is affected by the addition of other resources to the system.[28] The treatment of this phenomenon is largely a conceptual exercise in deciding whether to assign the reduction in capacity benefits to the marginal unit or all existing units. TURN supports assigning changes in capacity benefits on a vintage basis for purposes of

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[26] Governor Brown inauguration speech, January 5, 2015. (http://gov.ca.gov/news.php?id=18828)
[27] See SB 350 (DeLeon/Leno) and AB 645 (Williams/Rendon).
[28] Energy Division workshop presentation, December 16, 2014, page 41.

modeling solar compensation rates since this assumption aligns incremental installations with incremental changes in system value. The decline in capacity value only occurs if one assumes that there is no complementary technology, such as tracking systems or storage, available to enhance the capacity value of the incremental unit.

c) Electric Vehicle Penetration and Charging Scenario

The model includes two variables for electric vehicles (EVs). First, it allows the choice of EV Penetration (i.e., Low Penetration (1 million vehicles by 2030); Base Penetration (2 million EVs by 2030); and High Penetration (6 million vehicles by 2030)). Second, it allows the choice between "More" and "Less" Daytime EV charging.[29] ED chooses the Base assumption for EV Penetration for both bookend cases, but assumes "Less Daytime" charging for the Low Bookend and "More Daytime" charging for the High Bookend. TURN's scenario assumes Base EV Penetration and "Less Daytime" EV charging in order to be conservative regarding the impact of DER production on non-participants.

d) Zero Net Energy Homes

Energy Division included the choice of Zero Net Energy (ZNE) implemented and in effect as of 2020 or as a policy initiative that is not implemented. The ED bookend cases assume ZNE is not implemented in the high bookend and is implemented in the low bookend. TURN elected to assume that ZNE will not be implemented by 2020. It appears that ZNE policy has a *de minimus* effect on the ultimate value of solar, payback period, PCT or RIM, and only effects how many DER systems (and resulting capacity) are installed with TURN's preferred compensation mechanism (*i.e.* value-based, not retail rate-based) and policy input selection. The following table highlights this impact under a scenario using the low bookend case and a DGA equal to 5 cents/kWh:

[29] The More daytime charging selection assumes 35 percent of all EV charging occurs between 9am and 4pm. The Less daytime charging selection assumes 10 percent of all EV charging occurs between 9am and 4pm.

Table 3: Comparison of TURN's Base Case with and without ZNE

Scenarios	Total DER Adoptions	Forecasted Installations Post 2016 (MW)	Average Implied Payback (years)	Average PCT	Average RIM (All Gen)	Constant Compensation by Utility and Climate Zone Example[1]		
						Constant Compensation PGE (Zone PS)	Constant Compensation SCE (Zone 56)	Constant Compensation SDGE (Zone 1)
Low bookend Case w/ Value-Based Compensation								
SocV $.05	2,987,443	13,951	6.62	1.61	0.880	15.14	15.62	15.05
SocV $.05 + ZNE Policy by 2020	3,651,048	16,160	6.54	1.63	0.856	14.51	14.97	14.41

[1] The constant-compensation values provided here are the weighted average TOU rate and are for comparison purposes, only. The actual model run was done using TOU compensation.

This table shows that the primary impact of the ZNE assumption is to change forecasted installations from 13,951 MW to 16,160 MW while compensation rates and PCT/RIM ratios are not significantly affected. TURN recommends that the Commission develop the first VODE tariff without assuming ZNE policy will be implemented. Over time, the Commission can update this assumption based on actual developments for purposes of resetting the DGA value at the appropriate trigger point.

e) <u>Renewable Energy Credit (REC) Scenario</u>

The Energy Division assumes that behind the meter renewable generation reduces RPS obligations by serving as a bundled sales reduction for both the low and high bookend cases. TURN agrees with this approach based on current law and policy. This assumption should be revisited to the extent that any additional statutory direction is provided in legislation enacted during the current session.

2. *Avoided Costs*

The Energy Division models both the low and high bookend cases with identical values for Natural Gas Prices (default value), RPS Power Purchase Agreement Costs (default value), Ancillary Services Costs (1% of Market energy Purchases), and Marginal Avoided Energy Cost Locational Multiplier (100%). TURN uses these same assumptions for these categories. TURN offers recommendations for other avoided cost inputs in the following sections.

a) Carbon Market Costs

ED includes Carbon Market Costs at Base Value and High Value for the low and high adoption cases, respectively. While the higher trajectory is certainly possible, TURN conservatively chooses the Base Value to model its proposal in this case.

b) Resource Balance Year

The assumptions ED uses for the Resource Balance Year comprise "Model will Calculate" and the year 2017 for the low and high adoption cases. TURN believes that 2024 is close to the Resource Balance Year if one includes future additions of Energy Efficiency, DER, and renewables. However, it is not appropriate to include the very resources being evaluated when performing Loss of Load Expectation (LOLE) calculations for the purposes of understanding the resources' benefits, especially given that such resources are near the top of the loading order. As such, one should not assume that the resource being evaluated—in this case, DER—already exists in order to calculate its benefit, as when performing Loss of Load Expectation (LOLE) calculations for resources such as large gas plants. To avoid this problem, TURN believes that 2017 is the correct Resource Balance Year.

c) Marginal Avoided Transmission Costs

ED did not include a value for MATC in either bookend case. TURN recommends that the Commission include a value of $12.50/kW-yr ($2015) to account for the transmission investment that DER could displace. This value is based on PG&E's calculation of its demand-related marginal transmission capacity cost (MTCC), which it uses for "setting marginal cost-based price floors under Tariff E-31 and other non-ratemaking analysis where an MTCC may be needed."[30] Given that Federal Energy Regulatory Commission (FERC) has primary authority over transmission rates and is not a marginal-cost jurisdiction, there are few transmission marginal cost estimates, other than PG&E's available for use. TURN is not aware of any such calculations published by either San Diego Gas and Electric (SDG&E) or Southern California Electric (SCE). It is therefore reasonable and perhaps even conservative to use PG&E's estimate for this purpose.

d) Marginal Avoided Subtransmission Costs

The Energy Division includes Subtransmission at No Value and 100% for the low and high adoption cases, respectively. TURN recommends that the Commission use 100% for modeling purposes given that DER displaces utility investment at the subtransmission level because of significant diversity between customers and subtransmission substations.

e) Marginal Avoided Distribution Costs

The Energy Division includes a Marginal Avoided Distribution Cost (MADC) multiplier of 0% for the low bookend case and 100% for the high bookend case. TURN recommends that the Commission use 65% for modeling purposes given that not all distribution investments are avoided through DER additions. Specifically, distribution investment for new construction and secondary

[30] A.13-04-012. Ex. PG&E-2, Vol. 1 (Marginal Costs), pp. 4-2 – 4-3.

distribution infrastructure are by and large not avoided with installations of DER on the existing system. Since new distribution infrastructure is tied to new construction, additional DER should not be assumed to avoid the necessity for new construction of this infrastructure.

Regarding secondary distribution, DER should not be assumed to avoid these costs for the following reasons:

- Secondary distribution loads are unpredictable and based on loads at the final line transformer which may or may not be coincident with solar.

- Secondary distribution demand marginal costs only exist in a few places and are not spread over the entire system. The older secondary distribution that is related to demand for marginal costs is built in older neighborhoods and may be networked over several transformers but not a large area (a neighborhood block, which would not be considered a larger area, may be networked over several transformers).

- Modern secondary distribution is generally customer-related. It is essentially an economic choice on costs versus losses made by utility planners/engineers between attaching all the service drops directly to a transformer or running some secondary and attaching some of the service drops directly to the secondary.

TURN's recommendation of a 65% credit relies on information from PG&E's 2014 General Rate Case (GRC) Phase II filing.[31]

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[31] PG&E's distribution infrastructure capital spending forecast in its 2014 GRC Phase II: $576.6 million (Primary); $302.8 million (New Construction); $52.0 million (Secondary). The investment

3. *Distributed Energy Resource Costs*

a) Solar Cost Case

The Energy Division uses the High Cost case for the low bookend case and the Low Cost case for the high bookend case. While there is broad agreement that solar costs are continuing to fall, it is difficult to accurately predict the future trajectory of solar costs. TURN includes two runs of its proposal—one with the Base Cost trajectory and the other with the Low Cost trajectory—in order to illustrate the large effect that this assumption has on adoption rates.

b) Successor Tariff/Contract Program Cost Allocation

The Energy Division indicates in Table 1 of the Staff Paper that the allocation of program costs between participants and non-participants depends on the specific proposal to be modeled.[32] However, the model inputs provided by ED run both bookend cases with the assumption that the general body of ratepayers are responsible for net program costs. TURN models its proposal using the same assumption because we have added the transparent DGA to encourage development. Requiring DER customers to pay for net program costs would effectively remove the benefit of the DGA and defeat its purpose.

c) Assumed Utility Rate Escalation

The Energy Division assumes a 5% nominal utility rate escalation rate for both of the bookend cases. TURN believes that utility rate escalation is not relevant to the value-based compensation structure setting in the model that is consistent with the VODE tariff. For parties with proposals that rely on compensation structures tied to any portion of retail rates, TURN suggests that a 5% nominal/3% real rate, along with the model's default assumption of 2% inflation,

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for primary distribution infrastructure is, therefore, about 62%, which TURN rounds to 65% for purposes of modeling the NEM successor tariff. See PG&E's Excel-based marginal cost/revenue allocation workpapers (whose model, but not values, are confidential) in A.13-04-012.

[32] ED Staff Report, page 1-17.

is not a realistic or sustainable assumption. TURN supports an estimated increase of 1-2% in real terms. Depending upon how parties treat this assumption in their proposals, TURN may conduct further analysis and offer suggested modifications in comments.

d) Compensation Tax Treatment

The Energy Division assumes that compensation is Tax Exempt in both bookend cases. TURN adopts the same assumption and addresses the rationale for assuming that compensation remains tax exempt in Section IV(f).

4. Societal Inputs

The Public Tool contains fields for several categories of societal inputs in the Key Driver Inputs tab including the societal value of NOx reduction, PM-10 reduction, additional carbon reduction, reducing externalities related to RPS assets, and energy security. The ED bookend cases do not include values for these. TURN does not endorse non-zero values for these particular inputs. Instead, TURN models its proposed DGA by including a range of values (the default value of zero, followed by three, six, and ten) in the Societal Value Adder field within the fields included in the Public Tool's Base Rate Inputs tab. For each of the non-zero values in the range TURN models, we assume adder escalation of 2%.

5. Discount Rate Inputs

TURN agrees with the Energy Division assumed inflation rate of 2%. Although TURN does not recommend that the Commission use the societal discount rate for any purpose, TURN has not changed the default Societal Discount Rate (5%) in its model runs.

a) Participant Discount Rate

The Energy Division uses 9% as the discount rate for participants. TURN believes this rate is too high and elects a more modest 8% discount rate. This rate is probably overstated for the higher income customers likely to install solar.[33] Home-equity lines of credit can currently be financed with interest rates of between 3.5% and 6.38%,[34] or about half of the default discount rate assumed by ED. TURN uses 8% because some up-front cash (not borrowed) may be required from participants. This cash contribution would have a higher implicit cost of capital. While interest rates may increase from the current environment during the program period, they are unlikely to rise by such an amount that participants will face borrowing costs of 9% for solar and other DER in the foreseeable future.

b) Utility Discount Rate

The Energy Division uses 7% for the utility discount rate. TURN believes that the discount rate used in this case should be at least the 7.94% that is equivalent to the utilities' currently authorized rate of return on ratebase.[35] TURN rounds this value to 8% but understands that it may increase at some point during the program period if interest rates generally rise.

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[33] TURN is not estimating the discount rate for participants as the general body of residential ratepayers, for whom a higher participant discount rate might be required to evaluate programs of broader applicability like energy efficiency.

[34] Rates from CHASE bank, as of June 19, 2015 (see www.chase.com/home-equity, accessed on July 31, 2015). They are on an Average Percentage Rate (APR) basis and vary on the basis of the size of the line of credit and the borrower's strength.

[35] D.12-12-034, page 3. The average of 7.94% is the non-weighted average of the returns on ratebase for the four California Investor-Owned, which are, respectively, 7.90% (Southern California Edison), 7.79% (San Diego Gas and Electric), 8.02% (Southern California Gas), and 8.06% (Pacific Gas & Electric). An average weighted by customers, sales, revenue, etc., would be higher than 7.94% because SDG&E, which is much smaller than SCE and PG&E, receives a somewhat lower return on ratebase relative to those larger utilities. The return on ratebase received by the two largest utilities (i.e., SCE and PG&E) averages 7.98%.

VIII. SUMMARY OF TURN'S PROPOSAL FOR ADDRESSING GROWTH IN DISADVANTAGED COMMUNITIES

In order to encourage growth in the adoption of renewable DG for residential customers in Disadvantaged Communities (DACs), TURN recommends that an upfront financial incentive be provided to property owners of low-income housing in DACs (DAC alternative incentive). This proposal is similar to the second Energy Division Staff (Staff) proposal detailed in Attachment 2 to the ALJ Ruling Seeking Party Proposals issued on June 4, 2015.[36] Qualifying systems would then participate in TURN's proposed VODE tariff and receive value-based compensation including the Distributed Generation Adder.

The second Staff Proposal of an "incentive enhancement" to the standard NEM tariff proposed to apply the eligibility criteria used for the Multifamily Affordable Solar Housing (MASH) and the Single Family Affordable Solar Homes (SASH) programs. Participation in the MASH and SASH programs is limited to properties that are designated "low-income residential housing" pursuant to §2852(3) and whose residents have an annual income that is 80% or less than the area median income (AMI). TURN supports the use of these eligibility criteria because they will ensure that DG installations that qualify for the DAC alternative incentive will actually benefit low-income customers as well as be located in DACs.

A. Proposed Methodology for Defining Disadvantaged Communities

TURN agrees with Staff that the methodology for defining DACs should be based on both environmental pollution factors and socioeconomic factors. TURN supports Staff's proposal to define disadvantaged communities as the top 25% of impacted communities statewide as identified using the California Environment

[36] Energy Division Disadvantaged Communities NEM 2.0 Staff Proposal, pp. 2-16 – 2-19.

Protection Agency's (CalEPA) California Communities Environmental Health Screening Tool: CalEnviroScreen 2.0 (CalEnviroScreen).[37] TURN further suggests that some type of income eligibility criteria be applied for participation in the DAC alternative incentive program and recommends applying the same eligibility criteria used for the MASH and SASH programs. TURN also supports Staff's recommendation to use any updated version of the CalEnviroScreen methodology over time for the purposes of ongoing implementation of the DAC alternative incentive program.[38]

B. TURN's Proposal Addresses the Primary Barriers to Adoption of Renewable DG among Residential Customers in Disadvantaged Communities

Since TURN's proposed VODE tariff is designed to allow for a payback period of less than 10 years, any additional support for projects sited in DACs should come in the form of an upfront incentive. An upfront financial incentive is the best way to encourage growth of renewable DG adoption in DACs because it addresses one of the primary barriers to DG adoption—upfront installation costs. TURN agrees with Staff that an upfront incentive program "would overcome the economic barrier of accessing capital for the upfront costs of owning a system."[39] Furthermore, an upfront incentive can assist customers to qualify for credit to purchase or lease a renewable DG system.

Under both the existing NEM tariff and any successor tariff that ties compensation to the retail rate structure, CARE customers receive a lower compensation rate than non-CARE customers due to the discounted CARE retail rates that would be the basis for the bill credits. There is no reasonable basis for applying discounted rate credits for the valuation of Distributed Energy

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[37] *Id.* at p. 2-4.
[38] *Id.* at p. 2-6.
[39] *Id.* at p. 2-18.

Resources serving low-income customers. Because TURN's VODE proposal is independent of the retail rate structure, all residential customers would be eligible to receive the same value for the output of their renewable DG system. This change would help overcome some of the economic barriers to renewable DG adoption by low-income customers.

TURN acknowledges that an upfront incentive does not address property ownership barriers for single-family renters but it could, similar to the MASH program, help overcome ownership barriers for multifamily renters as was noted by Staff.[40] The upfront incentive proposal also does not directly address property structure barriers identified by Staff,[41] but it could free up participant funds for structural improvements. Marketing, outreach and linguistic barriers could be addressed with targeted marketing and outreach to low-income customers in DACs.

C. <u>Proposed Definition and Measurement of Growth Among Residential Customers in Disadvantage Communities</u>

TURN believes that given the low level of renewable DG deployment in DACs that the definition of "growth among residential customers" must result in a strategy that promotes growth beyond historic adoption levels in DACs. TURN supports the proposed Staff definition of growth as an

> increase in the total annual capacity installed by residential customers in disadvantaged communities in each IOU service territory beyond the total annual capacity installed in the year prior to implementation of the alternative for disadvantaged communities.[42]

Growth in renewable DG adoption in DACs is important for policy and equity reasons and the Commission must evaluate the success of the alternative

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[40] *Id.*
[41] *Id.* at p. 2-11.
[42] *Id.* at p. 2-8.

proposal relatively early into the adoption of the NEM successor tariff. Therefore, TURN supports the Staff recommendation that the Commission "revisit the alternative to determine if adjustments are warranted," and if the alternative does not result in adequate adoption of renewable DG "to surpass the capacity installation benchmark in at least one of the years over the first three years of the program."[43] TURN also recommends that installation benchmarks be set to levels that deliver annual net increases in DG adoption until the percentage of residential DG in DACs reaches an adoption target set by the Commission in the second phase of proceeding.[44]

D. The Requirements of Section 2927.1(b) should not be applied to the Disadvantaged Communities Alternative Incentive Program

Due to the unique characteristics of DACs and the historically low DG adoption rates in these communities, it is permissible if the DAC alternative incentive program provides benefits to all customers and the electrical system that are not approximately equal to the total costs. Under TURN's proposed VODE tariff, the primary subsidies qualifying DAC projects will receive are the proposed upfront incentive and the same DGA provided to all participants. The VODE ensures that compensation provided under the tariff is based on the costs and benefits of the renewable DG plus any additional amount needed to ensure sustainable growth in solar adoptions.

E. Costs and Benefits of Alternative Incentive Program Relative to the Costs and Benefits of TURN's Proposed Value of Distributed Energy Tariff

Since TURN's DAC alternative incentive proposal uses the same VODE tariff to compensate renewable DG for eligible customers, the only additional cost of the

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[43] *Id.*

[44] See subsection F below for an explanation of other activities related to the DAC alternative incentive that are appropriate for consideration in a subsequent phase of this proceeding.

DAC alternative incentive proposal is the cost of these upfront incentives. Given the low level of adoption of renewable DG in DACs and the potential economic benefits to low-income customers of increased DG adoption in DACs, the fact that the costs of the upfront incentives are not directly offset by the benefits is warranted in this situation. TURN echoes Staff's succinct and thoughtful recommendation that "due to the particular characteristics of the barriers to adoption, a cost impact to nonparticipating customers may be necessary and justified." TURN recommends that the Commission strive to minimize the cost impact to nonparticipating customers as much as possible.

F. Additional Funding will be required for the Disadvantaged Communities Alternative Incentive Program

Additional funding will be required for the upfront incentives TURN proposes in its DAC alternative incentive proposal. The upfront incentives must be substantial enough to help overcome the economic barriers to adoption that have historically resulted in low adoption rates in DACs. Regarding specific funding levels, Staff recommends that program funding levels and the incentive structure be developed in a second phase of this proceeding[45] and TURN agrees with this recommendation. A potential source of funding for the upfront incentives could be greenhouse gas allowance revenues. This source has the added benefit of not directly resulting in upward rate pressure for non-participating customers.

To the extent that such funding comes from rates, TURN recommends that the costs be allocated across all customers consistent with the treatment of the CARE program. This treatment recognizes that support for renewable DG in disadvantaged communities represents a public benefit that has been traditionally supported by all customers and not just those in the residential class.

[45] *Id*. at p. 2-17.

G. Legal Issues Associated with TURN's Proposed Disadvantaged Communities Alternative Incentive Program

TURN does not believe that there are any legal issues related to TURN's DAC alternative incentive proposal. TURN addresses legal issues relating to the VODE tariff in Section V.

IX. CONCLUSION

For the reasons provided in the prior sections, TURN urges the Commission to adopt a two-part successor tariff that incorporates the Value of Distributed Energy approach.

Respectfully submitted,

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Dated: August 3, 2015

ATTACHMENT 1

The Austin Energy "Value of Solar" Tariff

The Austin Energy "Value of Solar" Tariff

Austin Energy created the first "Value of Solar" (VOS) distributed solar rate applicable to residential customers. The tariff design has two basic components. First, the VOS tariff, or "VOST" relies on an annually-updated value of solar calculation designed to reveal the value to the utility (and other ratepayers) of a unit of generated solar energy. Like a full avoided cost methodology, the VOS calculation seeks to identify the "indifference price" at which the utility is neutral to the solar energy. Second, the tariff reconfigures the netting process to ensure that the utility recovers its full cost of serving the solar customer before any credit for solar generation is applied. This is accomplished in the VOST by creating a two-part tariff that fully charges for gross consumption, and fully credits the customer for gross production. These two steps result in a distributed solar rate that is more fair to the solar customer, the utility, and other utility customers. The VOST is administratively simple, aligns with other policy objectives, and decouples solar energy compensation from both consumption and incentives.

Austin Energy had adopted a VOS calculation methodology several years before applying the calculation to distributed rates. Previously, the calculation had been used to generate a reference or benchmark value against which to evaluate purchased power proposals, calibrate rebate and incentive levels, and evaluate resource plan components. As used by Austin Energy, the VOS calculation generates a long term levelized value of solar in cents per kilowatt/hour, based on five components.

These value components are energy, capacity, transmission capacity, transmission and distribution losses, and environmental value. More full-featured VOS calculations have emerged since Austin Energy first established its VOS model.

The goal of the calculation process is to estimate the total value of a unit of solar energy generated in the distribution grid, at or very near the point of consumption. Put another way, it is the conservative estimate of the cost that the utility would face in seeking to fill an order for a unit of energy with the same character as that generated from a local solar facility. That is, the utility would have to buy some energy, which would include some capacity value. The energy would have to be transmitted, with losses, over a delivery system, and pay transmission costs as well. Finally, the energy's environmental impacts would have to be equivalent through some kind of direct access transaction, or offset or "greened" with some kind of renewable energy credit or certificate.

The calculation is conservative for several reasons. It does not include so-called externality values related to local economic benefits, local environmental benefits or other valuable attributes of distributed solar. The levelized value is recalculated annually, so as to reflect current utility costs and prevent overpayments when system prices fall.

The concept behind applying the VOS calculation to a distributed rate stemmed from recognition of the limitations of traditional net metering, discussed above. The calculation confirms the common sense perception that locally generated clean energy, produced at or very near the point of use has “above average” value—that is, it does the work of generic system energy, but with no water use, environmental regulatory risk, fuel price volatility, or capital investment by the utility. Over time, distributed solar can extend the life of distribution and transmission assets, and defer the need for some of these investments. A 25- or 30-year levelization of avoided costs is essential to capture the benefits produced when a customer invests in distributed solar generation.

Once the VOS rate calculation methodology is set, the issue of tariff design arises. First, the VOS rate should be recalculated on an annual basis. The term at which the compensation rate is updated requires a balance of two key factors—current price signals and compensation stability. That is, annual resetting of the compensation rate to match the current VOS minimizes the risk that solar customers are over- or under-compensated for the energy they generate. On the other hand, stabilizing the compensation rate could improve customer confidence and reduce implicit hurdle rates for financing or calculating payback on solar investment. It should be noted that even with annual resetting of the VOS compensation rate, the use of a 25- or 30-year levelization dampens the impact of short-term market fluctuations on the VOS.

Second, in order to account for utility fixed and variable cost recovery requirements that remain with solar customers, the billing process under the VOST charges every customer for total energy consumption (whether offset by solar production or not) at their premises using the applicable existing distributed service rates. Then, a credit is applied for every unit of solar energy produced, at the value of solar rate. Excess credit is carried forward each month until the end of the year, when any remaining balance at the end of the year is erased. While little or no balance is anticipated, the use of a credit, rather than payment, and annual zeroing-out of excess balances helps preserve the status of the net metering calculation as “non-refundable credit” for tax purposes. In a 2-meter model, the solar production meter is situated on the customer side of the utility revenue meter. The netting process is exactly the same as with traditional net metering, with only the compensation rate applied to the gross production billing determinant changed to the VOS rate.

Under the VOST, customers have a strong incentive to use energy efficiently, in order to maximize the economic value they receive. They can be expected to make more on-peak energy available to the utility. Because the value is recalculated frequently, both the customer and the utility are treated fairly as solar and general system costs change. In the event that the system fails to generate as expected, the netting methodology ensures that the utility always recovers its costs of serving the customer because of the gross consumption charge. The calculation and netting approach eliminate the argument that other customers subsidize solar (except to the extent that such subsidies are embedded in the cost of service rates for consumption), and the VOS credit ensures that solar customers are not asked to unfairly subsidize other ratepayers. In the months following adoption of the VOST, Austin Energy reported continued strong growth in distributed solar installations and the opportunity to reduce capacity-denominated incentive rebates by more than 30%.

Though Austin implemented the concept with residential customers, it can be applied to commercial solar rates as well. The concept of distributed solar valuation as a foundation for setting an economically efficient compensation rate has potential application for use in setting rates for storage, energy efficiency and demand response, smart grid-enabled services, and other distributed energy resources.

ATTACHMENT 2

A Policy and Technical Review of Tax Issues and Distributed Solar Tariffs

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March 5, 2015

A Policy and Technical Review of Tax Issues and Distributed Solar Tariffs

Disclaimer: The author is NOT a tax attorney. This memorandum is a policy and technical review. Taxpayers or others seeking tax advice should consult a professional tax advisor.

This memorandum provides a policy and technical review of tax issues related to distributed solar tariffs. Specifically, this memorandum addresses issues raised in a highly publicized Information Letter Request submitted by a taxpayer in Austin, Texas. Though not expressly claiming credit for submitting the IL Request, The Alliance for Solar Choice (TASC) and SolarCity broadly distributed the Request with commentary in the trade press media.

In order to assess taxpayer eligibility for the incentive under Section 25D of the Internal Revenue Code ("Code") for "property which uses solar energy to generate electricity for use in a dwelling unit" located in Austin, Texas, I believe it is important to be apprised of the correct facts about the nature of the VOST and the design elements built into the rate. The key point is that the VOST was designed to be structurally identical to traditional Net Energy Metering ("NEM") in all respects except the rate applied to the solar energy system energy production billing determinant. That is, the VOST was designed as an offsetting credit tariff, and not as an instrument for a sale of electricity. The VOST was created to serve residential customers seeking to use solar energy to generate electricity for use in a dwelling unit served by Austin Energy, the municipal electric utility in Austin, Texas. I specifically designed the VOST under the advice of City of Austin General Counsel's office with the intention to preserve eligibility for the Section 25D incentive and to avoid the characterization of the credit for solar energy production as taxable income where a customer does not generate more than a minimal amount of excess energy.

Karl R. Rábago

MEMORANDUM ADDRESSING SECTION 25D AND RELATED ISSUES ASSOCIATED WITH UTILITY TARIFFS (INCLUDING THE AUSTIN ENERGY VALUE OF SOLAR TARIFF) APPLICABLE TO SOLAR ELECTRIC GENERATION AND USE

QUESTION PRESENTED

Is a customer/taxpayer who installs a solar generator on the customer side of the utility meter at their residential dwelling unit entitled to take a § 25D credit on the investment when the taxpayer receives bill credit under a Value of Solar Tariff ("VOST") as implemented by the City of Austin, Texas Electric Utility Department (dba "Austin Energy") for generation used to meet electricity demand at the dwelling unit?

SHORT ANSWER

Yes, because the VOST method of calculating solar energy value for behind the meter solar energy systems only changes the credit value of solar energy generated at the dwelling unit used as a residence by the taxpayer; the VOST only provides bill credit compensation for solar energy generated for use in that taxpayer residential dwelling unit; and the crediting of value on the customer bill at the value of solar rate does not change the fact that the customer is using the solar equipment to offset consumption charges by using the produced solar energy at the dwelling unit.

BACKGROUND

My name is Karl R. Rábago. I currently serve as the Executive Director of the Pace Energy and Climate Center, located at the Pace University School of Law, in White Plains, New York. I have some 24 years experience working in electric utility regulation and specifically with renewable and clean energy regulation, policy, programs, and markets. My experience includes service as the vice president for Distributed Energy Services at Austin Energy from April 2009 through June 2012, during which time I designed, developed, and implemented the Value of Solar Tariff in the course of my official duties. Additional experience includes service as a Public Utility Commission for the State of Texas, as a Deputy Assistant Secretary for the U.S. Department of Energy, and as an advocate, consultant, and executive in various electric utility-related positions in the private and public sector.

The Information Letter Request, attached, was made known to me through electricity industry media reporters, advocates, and others who received redacted versions of the request. The redacted IL Request is at Attachment A. The Request has been heavily publicized by the organization known as "The

Alliance for Solar Choice" (TASC) and its member companies. These publicity efforts are documented at Attachment B.

Working with my staff, stakeholders, and other members of the executive team at Austin Energy, I developed the VOST to improve upon and replace the traditional NEM tariff applicable to residential customers who installed solar energy generating equipment for use on their homes/dwelling units.[46] The VOST was designed to encourage the increased deployment and use of solar equipment by residential customers. Design criteria around which the VOST was developed included:

- Preservation of the basic electrical structure of the customer solar energy generation as a "behind the meter" system where the customer dwelling, including the solar equipment, only makes electrical contact with the utility through the utility revenue meter.
- Preservation of the familiar and effective "offsetting" methodology from NEM, whereby solar energy generation is used in the dwelling unit where the equipment is installed, and effectuated when the customer bill is credited for that generation against their total electricity charges on the bill.
- Preservation of the simple crediting mechanism for solar generation and avoiding the conditions and indicia of a "sale" of electricity from the customer to the utility.
- Improvement of the crediting or compensation rate for customer solar generation by changing the rate applied to the gross energy production billing determinant from the rough approximation of value inherent in credit at the otherwise applicable retail consumption rate to a more carefully and objectively calculated "value of solar" using a methodology first adopted by the utility in 2006.
- Preservation of the charge for energy use by the customer as the product of the retail rate times gross consumption that exists with net metering, while making the charge explicit on the customer bill in order to re-install the incentive for efficient use of energy that is often obscured under compressed net billing arrangements.

[46] A description of the issues and process relating to the development of the VOST can be found in an article published in the ICER Chronicle, at http://digitalcommons.pace.edu/cgi/viewcontent.cgi?article=1950&context=lawfaculty

APPLICABLE LAW

Under Section 25D of the Internal Revenue Code ("Code"), an individual is eligible to receive a personal tax credit equal to "30 percent of qualified solar electric property expenditures made by the taxpayer during such year."[47] The Code defines a qualified solar electric property [QSEP] expenditure as "an expenditure for property which uses solar energy to generate electricity for use in a dwelling unit located in the United States and used as a residence by the taxpayer."[48] The § 25D credit is subject to the "80-20 Rule" where the credit is only applied to the entire expenditure if "at least 80 percent of the use of a component or item of property is for personal residential purposes . . . ."[49] If less than 80 percent of the use of the component is for non-business use, then the credit is only applicable to that proportion of the use allocable to personal residential use.[50]

In its Q&A on Tax Credits for Sections 25C and 25D of the Code, the IRS provided further explanation of the energy credit:

> Q-26: A taxpayer purchases solar panels that are placed on an off-site solar array and connected to the local public utility's electrical grid that supplies electricity to the taxpayer's residence. The taxpayer enters into a direct contractual arrangement with the local public utility that supplies electricity to the taxpayer's residence to allow the taxpayer to provide electricity to the grid using a net metering system that measures the amount of electricity produced by the taxpayer's solar panels and transmitted to the grid and the amount of electricity used by the taxpayer's residence and drawn from the grid. The contract states that the taxpayer owns the energy transmitted by the solar panels to the utility grid until drawn from the grid at their residence. Absent unusual circumstances, the panels will not generate electricity for a specified period in excess of the amount expected to be consumed at the taxpayer's residence during that specified period. Can the taxpayer claim the § 25D credit?
>
> A-26: Yes. Section 25D(d)(2) defines a qualified solar electric property expenditure, in part, as an expenditure for property that uses solar energy to generate electricity for use in a dwelling unit used as a residence by the taxpayer. The taxpayer's expenditure for off-site solar panels under this type of contractual arrangement with a local public

47 I.R.C. § 25D(a)(1) (2012), 26 U.S.C. §25D (2013).
48 I.R.C. § 25D(d)(2).
49 26 C.F.R. § 1.23-3(g) (2014).
50 *Id*.

utility that supplies electricity to the taxpayer's residence meets the definition of qualified solar electric property expenditure.

Q-27: A taxpayer purchases and installs solar electric property to generate electricity for the taxpayer's own home and to allow the taxpayer to sell excess electricity to a utility. Unlike the taxpayer in Q-26, this taxpayer generates more than a minimal amount of excess electricity. Does this taxpayer qualify for the § 25D credit on the full amount of the solar electric property?

A-27: No. Under these facts, the taxpayer may not claim the § 25D credit for the *full amount* of the solar electric property expenditure because the property not only generates electricity for use in the taxpayer's home, but it also generates electricity for sale by the taxpayer. The taxpayer may only claim the § 25D credit *for the portion of the solar electric property expenditure that relates to the electricity generated for use in the taxpayer's home*. In addition, the taxpayer may be able to claim the § 48 credit for a portion of the solar electric property expenditure if the requirements of § 48 are satisfied.[51]

THE AUSTIN ENERGY VALUE OF SOLAR TARIFF (VOST)

Ordinance No. 20120607-055 of the City of Austin, Texas ("Austin Ordinance") provides a solar credit for "any customer receiving residential electric service who owns or operates an on-site solar photovoltaic system with a capacity of 20 kW or less that is interconnected with Austin Energy's electric distribution system."[52] The Residential Solar page of the Ordinance is at Attachment C.

Monthly Charges
Billable kWh under this rate schedule shall be based on the customer's total energy consumption during the billing month, including energy delivered by Austin Energy's electric system and *energy consumed from an on-site solar system.*

Solar Credit
For each billing month the customer shall receive a *non-refundable credit* equal to the metered kWh output of the customer's photovoltaic system, times the current Value-of-Solar Factor plus any *carry-over credit* from the previous billing month. . . .

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[51] I.R.S. Notice 2009-41, Sec. 3.03 (May 11, 2009) (emphasis added).
[52] Austin, TX, Ordinance 20120607-055 (June 18, 2012). (Austin Energy's current rates can be found at www.austinenergy.com, and then navigating to "rates," and "approved rate schedules.")

> Any amount of *solar credit* in excess of the customer's total charges for electric service under the residential rate schedule *shall be carried forward and applied to the customer's next electric bill. . . .* [53]

Under the VOST as adopted, any remaining credit balance at the end of the year is zeroed out.[54] Under a Resolution adopted by the Austin City Counsel in August 2014, at Attachment D, the credit under the VOST rolls over until the solar-generating customer ceases to be an Austin Energy customer, but the credits are not transferable and cannot be applied to anything other than the customer's electric bills, though this has not yet been implemented in a revised tariff.[55] The solar customer never receives monetary compensation; the most the customer can gain from the solar credit is a net-zero electric bill.

ELECTRICAL SYSTEM PHYSICAL DESCRIPTION UNDER VOST AND NEM

An important indicator of whether the solar equipment is used for non-business purposes at a dwelling unit appears in the physical layout and arrangement of solar and electrical equipment at the dwelling unit. In the electric industry, the interconnection of electric generators is typically described as either of two arrangements - a "behind the meter" configuration or a "utility side of the meter" configuration.

Both traditional NEM and VOST use a "behind the meter" connection configuration. The solar equipment on the roof feeds into an inverter and often, a solar production meter that is connected to the dwelling unit electrical system. The dwelling unit electrical system is consolidated in the circuit breaker box, which is connected to the utility revenue meter. In this configuration, solar energy production blends with electricity consumption from the utility. The solar energy is used at the dwelling unit to the extent that it can be used there, and is exported to the utility grid only in situations of excess production. The result produces the net consumption or excess production that is seen by the utility meter.

In a utility side of the meter arrangement, sometimes called an "in front of the meter" configuration, the solar system is connected directly to the utility grid through a dedicated solar meter on a circuit that is separate from the dwelling unit electrical circuit. In this configuration, solar generation is separately measured and flows directly to the utility without being electrically used in the dwelling unit. This is *not* the arrangement used in traditional NEM or the VOST.

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[53] *Id. Emphasis added.*
[54] *Id.*
[55] Austin, TX. Resolution No. 20140828-157 § 2(b) (Aug. 28, 2014).

Q&A-26 presents a hypothetical situation regarding off-site solar generation and virtual net metering. It establishes that, when a renewable energy system is offsite or in front of the meter, an explicit provision that title is not transferred can be indicative of personal non-residential use. Under traditional NEM and the VOST, such a provision is not necessary and is implied by the connection of the system *behind the meter*. Many NEM tariffs make no mention of title of transfer, but there is no doubt that net metering credits come with § 25D's non-residential use limitation only for excess generation.[56] Lack of mention of title transfer is not dispositive of whether a VOST falls outside the scope of § 25D, especially when the VOST is designed to operate behind the meter like a traditional NEM.[57]

DISCUSSION

Net Metering versus VOST

Under a traditional net energy metering (NEM) billing system, the utility credits the customer's production of solar energy against household consumption, resulting in "net" energy consumption.[58] If production exceeds consumption during the netting period, the electricity provider usually gives the customer a credit at a certain rate (sometimes the utility avoided cost).[59] Traditionally, NEM billing systems only produce a single number representing the net positive or negative energy consumption by a customer, to which the appropriate rates can be applied. (This was, in fact, the only way that utility bills could be calculated and presented in the era of mechanical disk residential meters, and before the modern era of digital meters.) The single number presented under NEM has always been the sum of two numbers, known as billing determinants: production and consumption. Under NEM, the value of solar production up to the point of consumption equals the utility rate for regular consumption (i.e. the retail rate).

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[56] *See, e.g.*, Distributed Generation from Renewable Sources Rider, City of Austin Electric Rate Schedules, http://austinenergy.com (Navigate to "rates," then "approved rate schedules." Also available at http://goo.gl/nUpa5N). *See also* I.R.S. Notice 2009-41, Sec. 3.03, Q&A-27 (May 11, 2009) (Under NEM, a customer that generates more than the minimal amount of energy may not claim the § 25D credit for the full amount of the expenditure, but can still claim partial credit for generation for use in the taxpayer's home).

[57] Unlike Austin Energy's VOST, some NEM and VOST rates could be designed, hypothetically, to operate as a Feed-in Tariff (FIT) to expressly transfer ownership of all energy production to the utility. In such a case, with express title transfer and with "utility side of the meter" installation, the customer would not be using the solar energy generated at the residential dwelling unit under § 25D.

[58] Karl R Rábago, *The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff*, SOLAR INDUSTRY (Feb. 2013), *available at* digitalcommons.pace.edu/cgi/viewcontent.cgi?article=1949&context=lawfaculty.

[59] *Id.*

The tariff formula, excluding irrelevant fixed customer charges, is as follows:

$$1. [Gross\ Consumption - Gross\ Production]\ x\ Retail\ Rate = Bill$$

expanded and equal to:

$$2. [Gross\ Consumption\ x\ Retail\ Rate] - [Gross\ Production\ x\ Retail\ Rate] = Bill$$

The tariff formula for NEM is more complex when the compensation rate for solar generation that is in excess of gross consumption during the billing period differs from the retail rate. In such NEM programs, only production up the point of gross consumption receives the retail rate. Excess production receives a different rate, and is carried over at that rate or cashed out to the customer. It is important to note that the receipt of a credit at a different rate for excess production during the billing period does not define whether the excess production is or is not for non-business use. The purpose of the use and the guidance provided by the 80-20 rule make it clear that the use, and not the rate, is determinative.

The VOST tariff structure is built on the NEM tariff structure. The VOST changes the rate applied to the gross production billing determinant, and eliminates the need for a separate rate for generation that is excess to gross production. The VOST uses the value of solar rate in lieu of the retail rate for application to the gross production billing determinant in order to improve the economic accuracy and, therefore, efficiency in the rate for customer generators. As a result, the tariff formula for the VOST can be represented as:

$$3. [Gross\ Consumption \times Retail\ Rate] - [Gross\ Production\ x\ VOS\ Rate] = Bill$$

Structurally, then, a VOST is identical to traditional NEM in all respects (i.e., formula 3 is structurally identical to formula 2, which is equal to formula 1), except for the rate applied to solar energy billing determinant, which takes into account such things as utility cost savings and environmental values to create a separate rate.[60] Like an NEM system, the ultimate purpose is to offset a customer's consumption before any excess production is transferred to the utility.

Production and consumption are calculated separately because the VOST and retail rates differ. If the VOST value exactly matched the retail rate for

[60] Austin, TX, Ordinance 20120607-055 (June 18, 2012) ("The Value-of-Solar Factor … shall be administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits.") See also, Karl R Rábago, *The 'Value of Solar' Rate*, *supra* note 13.

consumption, the amount of credit received by the customer would equal the amount received in an NEM system.

The VOST results in a single monthly transaction between the utility and the customer, just as with conventional NEM. The bill presented to the customer explicitly reveals the gross consumption and the gross production billing determinants used in both NEM and VOST but often obscured in NEM billing. This change in bill presentment does not create multiple transactions. Instead it was implemented in order to improve customer understanding of their electricity use and production, and to provide the customer with prices signals that would inform efficiency and conservation investment decisions.[61]

<u>The VOST credit is conditioned on Residential Use</u>

The VOST credit is conditioned on the customer's retail consumption – the energy used in the dwelling. Under the VOST, the customer cannot receive cash.[62] The credit is only applicable to offset energy use at the customers dwelling.[63] The taxpayer Information Letter Request pending before the Service addresses a situation in which all produced solar energy must be sold to the utility, a condition that does not exist in the VOST. The condition represented in the Request is hypothetical only.

Under the Austin VOST tariff, as with NEM, residential use is a necessary condition for the production credit to have any value. When customers generate electricity at their residence, they earn temporary credit with Austin Energy, which is applied against their monthly energy consumption bill. It cannot be redeemed without retail consumption – the credit is non-refundable. Excess production credits rollover to the next month's retail consumption costs. As a result, the customer gains no benefit unless the condition of residential use has been met.[64]

<u>Errors in the Information Letter Request</u>

As discussed above, the Request misstates and mischaracterizes key facts about the structure of the Austin Energy VOST. Rather than addressing the application of § 25D and other Service Notice provisions to these incorrect and, therefore, hypothetical circumstances, it is more appropriate to address the actual situation that exists in the Austin Energy VOST.

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[61] *Id.*
[62] Austin, TX. Ordinance No. 20120607-055 (June 7, 2012) ("…the customer shall receive a non-refundable credit equal to the metered kWh output of the customer's photovoltaic system").
[63] *Id.*
[64] *Id.*

The Request essentially asserts that a credit for solar generation from a behind the meter solar system at a value different from the otherwise applicable retail rate transforms generation for residential use into generation for business sale. The crediting rate, in and of itself, is not a determining factor under § 25D, and is not relevant when the tariff in question is structured identically to traditional net metering. The determining factor is the use made of the solar energy. In this regard, the electrical arrangement of the system, the tariff structure, and the amount of energy generation relative to consumption (the 80-20 rule) are relevant in informing the use determination.

The Request takes the position that the VOST creates and constitutes two separate transactions because two different rates are used for the customer/taxpayer gross consumption and gross production. As explained above, the VOST is structurally identical to NEM and closes the single monthly transaction between the customer and the utility with a single bill. The Request confuses the use of multiple rates and multiple billing determinants on a single bill with the existence of multiple transactions. In fact, most customer monthly bills include multiple rates and multiple determinants.

The position taken in the Request is that ineligibility for the § 25D results from changes in the crediting rate applied to solar energy production, regardless of the use that the taxpayer makes of the energy or of the quantity of energy produced by the solar energy system. Such an interpretation is an absurd result, contrary to the purpose of the § 25D.[65] Differences in the crediting rate between that applied to production that offsets consumption and production that is excess to consumption exist under many NEM statutes and programs. These differences cannot and do not give rise to ineligibility for the § 25D credit.

The Request erroneously concludes that VOST credits constitute a "sale" for business use by ignoring the VOST's condition precedent of residential use. By claiming that the customer "sells" all of their solar-generated electricity for credit, in isolation of their consumption, the Request misstates the facts, and asserts a claim unsupported by the plain language or operation of the VOST. A better interpretation of the Code is to align it with Q&A-27, cited above, wherein only more than a minimal amount of *excess* production is treated as non-residential use. This remains a correct test, and retains the incentive to offset

[65] 154 Cong. Rec. S9238-02 (Sept. 23, 2008) ("…Within [§25D] there are strong incentives for all types of clean energy, including solar power, geothermal, wind and biofuels. If somebody wants to add solar power panels to their home, there are currently some incentives in today's law, but those incentives are not adequate. We encourage more and more people to put solar power into their own homes so they can actually help solve the energy problems we have in this country in their own home.") ("Here is where America is headed…We will produce a lot of energy from renewable sources. We will maximize the opportunity to receive energy from the Sun.") The Renewable Energy and Job Creation Act of 2008 extended 25D tax incentives for residential use originally provided for in the Energy Policy Act of 2005.

energy consumption by installing a solar generator for the taxpayer residence. For customers looking to profit from selling energy to the utility, the 80-20 Rule already effectively limits the amount of residential credit they can receive for investing in solar generation.

The Request asserts that the Austin Energy tariff creates an implied or quasi contract in an effort to bolster its argument that crediting solar energy production at the value of solar rate creates a mandatory sale of all of the generation from the solar equipment. The Request bases this argument on the use of the word "any" in the VOST. This argument strains the plain meaning of words in an effort to create evidence of a transfer of title and ownership of the generated solar energy that was expressly not made a part of the VOST.

The Request attempts to argue that the credit provided in NEM or VOST constitutes a payment within a "transaction" and therefore is gross income and not excluded under § 136 as a subsidy to the taxpayer. This jumbled logic confuses a number of important concepts and facts. First, as explained above, the credit and the charges for consumption on the taxpayer's electricity bill that is provided under the structurally identical NEM and VOST tariffs is not a payment associated with a sale. Second, the credit applied to the customer bill is not a subsidy, but an incident of the customer's use of the solar generation equipment. Third, use of the system is governed by the 80-20 safe harbor rule, whereby "[i]f less than 80 percent of the use of an item is for nonbusiness purposes, only that portion of the expenditures for such item which is properly allocable to use for nonbusiness purposes shall be taken into account."[66]

CONCLUSION

A production credit based on the value of solar as incorporated in the VOST does not transform an otherwise non-business use into a business use of solar generating property. The taxpayer should be entitled to the appropriate tax credits for solar electric generation.

[66] I.R.C. § 25D(e)(7).

ATTACHMENT 3

TURN's Public Tool Input Modifications

A summary of the public tool input selections TURN used to evaluate its proposal are included in Table 2 "Summary of Input Selections for ED's Bookend Cases and TURN's Proposal." Section VI of the proposal includes justifications for the following modeling inputs that TURN modified:

1. Policy inputs
    a. 2030 RPS Policy Target
    b. Marginal Generation Capacity Avoided Cost Treatment
    c. EV Penetration & Charging Scenario
    d. ZNE Homes
    e. REC Scenario
2. Avoided cost inputs
    a. Carbon Market Costs
    b. Resource Balance year
    c. Marginal Avoided Transmission Costs
    d. Marginal Avoided Subtransmission Costs
    e. Marginal Avoided Distribution Costs
3. DER costs
    a. Solar Cost Case
    b. Successor Tariff/Contract Program Cost Allocation
    c. Utility Rate Escalation Assumption
    d. Compensation Tax Treatment
4. Societal inputs
5. Discount rate inputs
    a. Participant Discount Rate
    b. Utility Discount Rate