STATE OF CALIFORNIA
BEFORE THE CALIFORNIA ENERGY COMMISSION

In the matter of:	)	Docket No. 14-RPS-01
	)	
Amendments to Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities	))))))	SMUD Comments Pursuant to: STAFF WORKSHOP RE: Enforcement Procedures for the Renewables Portfolio Standard for Publicly Owned Electric Utilities
	)	July 28, 2014

Comments of the Sacramento Municipal Utility District (SMUD) Pursuant to the Staff Workshop RE:

Enforcement Procedures for the Renewables Portfolio Standard for Publicly Owned Electric Utilities

Thank you for the opportunity to provide comments on the topic of potential changes to the ***Enforcement Procedures for the Renewables Portfolio Standard for Publicly Owned Electric Utilities*** (RPS Regulations). A variety of important issues were discussed at the July 11, 2014, Staff Workshop and raised in Attachment A to the workshop notice. SMUD provides answers to the questions in Attachment A and supports related and additional changes to the RPS Regulations as described below.

While the July 11th workshop notice identified five general topics where changes to the RPS Regulations would be considered, SMUD does not believe that these are the only areas where regulatory changes should be considered. SMUD notes that these regulations are relatively new, having been adopted just one year ago and having not yet been amended. There have been several compliance reporting filings, including the overall compliance filing for the first three-year compliance period, that document renewable procurement activities by POUs pursuant to the RPS Regulations. Informally, SMUD and other POUs were assured that there would be a general "Scoping Workshop" to elicit public opinion about the scope of a set of regulatory amendments, similar to that held in January to elicit opinion about potential changes to the RPS Eligibility Guidebook. Given that the proposed rulemaking is still in a preliminary phase, SMUD asserts that regulatory changes outside the five topics identified should be considered, and this set of initial comments by POUs and others be considered to be helping to identify the "scope" of potential changes to the RPS Regulations.

SMUD's comments below are divided into three main sections. First, SMUD provides concise and specific answers to the questions in Attachment A. Second, SMUD elaborates in particular on the subject raised by Topic 2 – the question of how POU-owned or procured DG systems should be treated with respect to product content categorization. SMUD continues to believe that distributed generation resources that are connected to a distribution system within a California balancing authority should be a Product Content Category 1 (PCC1) resource, consistent with the plain language of SBX1 2. For many such installations, in which energy is procured bundled with the RECs from the systems, there should be no question as to the PCC1 status, regardless of where that energy is used. Third, SMUD provides recommendations on additional changes to the RPS Regulations that should be considered in this rulemaking.

Section 1: Attachment A Issues

1. Implementation of Senate Bill 591

Senate Bill 591 (Cannella, Chapter 520, Statutes of 2013), was signed into law on October 3, 2013. SB 591 amended Public Utilities Code (PUC) section 399.30 (k) and establishes an RPS exemption for a local publicly-owned electric utility (POU) that receives greater than 50 percent of its annual retail sales from its own hydroelectric generation that is not an eligible renewable energy resource (and that meets other specific criteria), and excuses the POU from having to procure additional eligible renewable energy resources in excess of either:

- the portion of the POU's retail sales not supplied by its own qualifying hydroelectric generation, or
- the POU's adopted cost limitation.

If a POU qualifies for this exemption, the POU is not required to purchase additional eligible renewable energy resources in excess of the procurement requirements of subdivision (c) of PUC section 399.30 (c).

… [Text not included] …

SMUD Response: *SMUD does not qualify for a SB 591 exemption and has no comments on this issue.*

2. Portfolio Content Category for POU Owned or Procured DG System

The Energy Commission is exploring whether generation from a RPS certified facility consisting of a distributed generation system either owned by a POU or from which the POU procures generation could be classified as PCC1 under PUC §399.16 (b)(1) and §3203 of the POU regulations. Is it appropriate to classify generation from an RPS-certified DG system as PCC1 if it is either owned by a POU or the POU procures bundled electricity generation from the DG system? If so, under what conditions?

Issue: It may be appropriate under the statute and regulations to characterize electricity generation from POU-owned DG systems as PCC1, because: i) the DG facility is owned by the POU, ii) ownership is synonymous with procurement under PUC §399.11

(f), iii) the DG system is interconnected to a California Balancing Authority (CBA) or distribution facilities used to serve end user within a CBA, and iv) the POU (as the owner of the DG system) is acquiring both the electricity generation and the associated renewable energy credits (RECs/WREGIS Certificates) from the DG system as a bundled product.

a. Are there circumstances when it would <u>not</u> be appropriate to classify electricity generation from a POU-owned DG system as PCC1? Would it matter if the electricity generation was immediately sold to a POU customer, rather than transmitted to the POU's distribution system? This could occur where the POU-owned DG systems was located on the customer's site.

SMUD Response: *There are no circumstances in which electricity generation from a POU-owned DG system should be thought of as anything other than PCC1. The law certainly does not point to any other categorization for a resource that meets the written requirements of PCC1* ***and*** *also meets the "bundled" requirement that the CEC has interpreted in the law. Policy considerations also strongly suggest that PCC1 categorization is appropriate for these resources. It does not matter that the electricity generation is immediately sold to a POU customer on the POUs distribution system. Any distinction between electricity used by one POU customer on the distribution system as opposed to others cannot be found in or derived from the law, and there is no policy basis to attempt to make such a distinction.*

SMUD believes that ***all*** *distributed generation interconnected to our distribution system should be PCC1. In particular, systems in which there is not only the interconnection requirement from the law, but also a bundled purchase by the POU of energy and RECs must be PCC1, regardless of where or to whom the POU sells the electricity. At that point, the POU has procured a PCC1 product. The RPS already affords PCC1 status to RECs in which a POU purchases bundled electricity and RECs from a resource connected to a California BA but sells the electricity outside its service area and keeps the RECs on behalf of its customers. The RPS also allows a POU to procure bundled PCC1 product and hold the RECs for later use. Hence, procuring a bundled PCC1 product from an interconnected and POU-owned DG system must also be considered a viable PCC1 procurement, even if the electricity is immediately sold to a POU distribution customer. There is nothing wrong with this.*

From a policy perspective, SMUD believes that it will become increasingly important to consider DG as a PCC1 resource under the law. Failure to do so establishes disincentives to procure DG, or consider DG as a renewable resource. The Legislature has seen fit to place significant constraints on the amount of PCC3 resources that RPS entities can procure, with decreasing "caps" that eventually reach just 10% of one's overall RPS procurement. If DG remains considered PCC3, there is an inexorable crash in the future as DG such as distributed DG grows to exceed the 10% limit. With the potential loss of SB 1 incentives, likely reductions in the value of net-metering, and the potential loss of favorable federal and state tax treatment, the value of participation in the RPS becomes more important. Failure to recognize this value as a state policy *tool runs counter to achieving the Governor's 12000 MW DG goal, and cannot help but constrain the growth of distributed solar resources.*

Furthermore, because of the lower PCC3 value currently accorded to most distributed generation installations, there is a tendency to consider the transaction costs of RPS participation as "outweighing" the value of RPS inclusion for these systems. This simply increases RPS costs, as resources that are being installed are not counted and costs are then incurred to procure other resources. In addition, it reduces utility incentives to facilitate and procure distributed solar resources, potentially causing slower growth in the distributed solar PV marketplace.

These issues are elaborated on further in Section 2 of these comments.

Issue: POU-owned DG systems can be distinguished from DG systems owned by a customer or third party to offset the customer's on-site load. When a DG system is owned by the customer or a third party to offset the customer's on-site load, some or all of the electricity generated by the DG system is consumed on-site. Typically, under this scenario only the RECs associated with the generation from the DG system and the net surplus generation from the system is available to be procured by a POU. The RECs associated with the electricity generation consumed on-site would be unbundled and classified as PCC3, and the RECs associated with the net surplus electricity generation from the system would be characterized as PCC1. This is consistent with the net-energy metering provisions of PUC §2827 (h), which provides that an electric utility shall own any RECs for net surplus electricity purchased pursuant to the utility's net surplus electricity compensation rate, and that any RECs associated with electricity generated by the customer-generator and utilized by the customer-generator shall remain the property of the customer-generator.

b. Under what circumstances, if at all, would it be appropriate to classify electricity generation from a customer-owned or third party-owned DG system as PCC1, when that electricity generation is used to meet the customer's on-site load?

SMUD Response: *As mentioned above, SMUD believes that **all** distributed generation interconnected to our distribution system should be PCC1. If the electricity is used to meet onsite load, then it is serving our distribution customers and system. SMUD has a significant amount of renewable procurement where we have purchased the RECs from systems installed with SB 1 rebates (a lower rebate is available if the customer wants to retain the RECs from their system). This is in contrast to IOU service areas where the utilities have not been allowed to retain the RECs. The CEC may consider such procurement where some of the electricity is used on-site as "unbundled", and under that interpretation, SMUD still maintains that the procurement is PCC1, because bundling is not required for a resource interconnected to our distribution system.*

SMUD would also suggest that electricity used onsite can be considered as "bundled"; meeting the CEC's current stringent interpretation here. The logic here is that SMUD is in effect buying the electricity along with the REC at the customers retail rate – we are *not simply buying a set of RECs, but actually procuring electricity from the generator and selling it back to our customer under a net metering agreement. When an on-site system is exporting to the grid, we purchase the electricity at retail cost; when an on-site system is generating to serve load on the site, the customer is receiving value from the system equivalent to our purchase of that electricity at retail cost. This is a reasonable interpretation of how net metering works that results in the proper assignment of the higher-value PCC1 label to these systems. TURN provided very similar logic in initial comments at the CPUC on the content category decision, suggesting that electricity from a system that is procured through a net metering tariff could be considered bundled, and hence treated as PCC1:*

> *"For behind the meter renewable generation taking service under a net metering tariff, TURN believes that any transaction involving the transfer of the RECs to the retail seller serving the net metered customer should count as a §399.16(b)(1) product. In this situation, the retail seller is essentially purchasing a bundled renewable product since the customer/generator is being compensated for both the energy provided to the retail seller and the RECs associated with the energy." [TURN Opening Comments On Implementation Of Portfolio Content Categories, August 8, 2011]*

One only need consider the difference in actual physical result between the case described in the question and a true purchase of out of state unbundled RECs to see the rightness of this path. In the case described, the utility is procuring RECs and electricity from a DG resource, and the distribution customers of the utility (including the on-site customer) are receiving that electricity. In an unbundled RECs purchase, the utility is only procuring RECs, and their distribution customers do not receive any electricity whatsoever from the underlying resource. This is a fundamental difference that is essentially ignored in the current framework.

These issues are elaborated on further in Section 2 of these comments.

c. Would it be appropriate for a POU to procure all of the bundled electricity generated by a customer-owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load and claim the procurement as PCC1? Could such a transaction comport with §3203 (a)(1) of the Energy Commission's regulations that precludes a POU from buying a bundled electricity product and then reselling the underlying electricity from the bundled product back to generator from which the electricity product was purchased?

SMUD Response: *Yes, it would be appropriate for a POU to procure all of the bundled electricity generated by a customer-owned DG system and immediately sell back to the customer all of the commodity electricity to serve their on-site load, and have this transaction be deemed PCC1. Such a transaction should not be considered a violation of §3203 (a)(1) of the RPS Regulations. One must simply look at the underlying* *justification for §3203 (a)(1) – that a transaction in which electricity is sold back to the generator is undistinguishable from an out-of-state unbundled REC transaction, where no actual electricity is interconnected to or scheduled to California. In the cases intended to be prohibited by §3203 (a)(1), the generator in the transaction is expected to be then reselling energy to another procurer. However, in the subject case, the utility is in reality purchasing RECs and energy and reselling that energy to a* ***customer*** *for on-site use. This is fundamentally different in physical effect. In the former case, the utility has no energy from the initial procurement to sell to their customers and must use substituted energy to associate with the RECs. In the latter case, the utility has the electricity from the original procurement to sell to customers, and it should not matter that some or even all of the electricity is sold to a particular customer – the one with the on-site DG system.*

These issues are elaborated on further in Section 2 of these comments.

d. If the customer installed the DG system to offset the customer's on-site load, and the system is being operated for this purpose, is the system's electricity generation available to be procured by a POU? How would the generation under such a transaction compare with generation from a central station facility that uses a portion of the facility's generation to satisfy on-site load, and sells the facility's net surplus generation to a utility via a power purchase agreement? An example of a central station facility could be a biomass facility that uses a portion of the facility's electricity generation to meet the on-site electrical load of related timber milling operations. How would your response differ, if at all, if a third party owned and installed the system?

SMUD Response: *Yes, DG systems to offset on-site load are available for procurement by the POU. As mentioned above, SMUD procures the RECs from the majority of its on-site SB 1 systems. We also sell electricity, obviously, to our customers. Electricity generated on-site by our customers is clearly available to those customers, and when that electricity is exported, to other customers connected to our distribution network. There is not a significant difference in terms of "availability" to our customers between a system interconnected to our distribution network on the customer size of the meter and one interconnected to our distribution network on the utility side, because in both cases, the electricity is available to be procured and is provided to our distribution customers. There is only a potential difference in how much electricity is provided to one distribution customer versus another. The key issue that arises with this set of questions is who owns or procures the RECs that may be associated with on-site generation.*

In the example situation described in the question – a biomass facility that uses some energy to serve on-site lumber mill load – neither the energy used on-site or the associated RECs are procured by SMUD. SMUD would typically purchase only the bundled energy and RECs exported by the system to the electricity grid. There would be no commercial arrangement involving SMUD associated with the on-site electricity use

– that would be solely the province of the biomass facility and the lumber mill. Presumably, if allowed and available, the RECs associated with on-site lumber mill use would be available for purchase by the host utility or any other RPS participant as a PCC3 product. However, in the case of the typical on-site SB 1 system, SMUD is procuring the RECs from the entire system, and has a commercial arrangement called net metering that is associated with all of the on-site energy as well as exported energy. As described above, this can reasonably be considered a bundled procurement of RECs and energy, with that energy, as with all RPS procurement, resold to our distribution customers. The key difference is the commercial arrangement, or "contract", that involves both energy and RECs.

TURN supported the distinction argued above in reply comments to the CPUC regarding the initial portfolio content category determination for the RPS:

> *"The real question is whether the procurement of RECs from these facilities [behind the meter renewable generators such as wastewater digester gas generators] is properly classified as bundled or unbundled. Consistent with TURN's proposal in opening comments, a transaction should count as bundled if the retail seller serving the customer with distributed generation procures the RECs and compensates the customer for the associated energy produced by providing the facility with a retail rate credit. Under this arrangement, the retail seller entering into this arrangement is purchasing a bundled renewable energy product and the transaction should not be considered equivalent to unbundled renewable energy credits. So long as the underlying generation facility meets the relevant interconnection or scheduling requirements, the retail seller may count the transaction towards the first product category. If the procurement of RECs occurs without compensation for the associated energy produced by the distributed generation facility, then the transaction should be treated as unbundled and assigned to the third product category." [TURN PCC Reply Comments, August 19, 2011]*

e. How, if at all, would the net-energy metering provisions of PUC §2827 be implicated if a POU were to procure all of the bundled electricity generated by a customer owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load?

SMUD Response: *This would not be a typical net metering arrangement. Up to the legislated net-metering cap, a utility would be required to accept net metering, but could offer an alternative arrangement as described. Under such an arrangement, the contractual structure could include rates similar to the retail rate compensation available under net-metering or could reflect a different compensation to the customer for generation provided. Regardless of the compensation structure, this arrangement would not likely be considered net metering, and would not likely have any "implication" on the separate net metering structure. It would, however, be a bundled procurement of*

RECs and energy, and hence be properly classified as PCC1 even under the CEC's interpretation of the category (requiring bundling).

3. Definition of "retail sales"

The Energy Commission is considering whether the current definition of "retail sales" should be clarified in §3201 (bb) of the Energy Commission's regulations for POUs.

Issue: Based on conversations with POU representatives, it is not clear that POUs are determining their "retail sales" in the same manner. For example, some POUs may be excluding electricity demand from other departments, units, or enterprises within the municipality, while other POUs may not be doing so. It may be difficult for a POU to determine where to draw the line between the POU/municipality's consumptive demand and "retail sales," particularly if the POU serves related, but separate, entities within or associated with the municipality, such as enterprise zones or joint powers authorities.

a. Does the definition of "retail sales" need be to clarified to ensure POUs are properly excluding their consumptive loads in determining retail sales?

SMUD Response: *SMUD has no comments on this issue.*

b. If clarifications are needed, how should the definition of "retail sales" be revised to properly exclude a POU's own consumptive demand, but capture all sales to its retail customers?

SMUD Response: *SMUD has no comments on this issue.*

4. Definition of "resale"

The Energy Commission is considering whether "resale" should be defined in the Energy Commission's regulations for POUs. Please respond to the following question.

a. The Frequently Asked Questions posted on our website includes the following definition of resale: A purchase is considered a "resale" if the POU is buying the electricity product from another California RPS□obligated utility.

b. Is this guidance sufficient or is additional guidance needed, and if so in what areas and why?

SMUD Response: *SMUD believes that changes to the RPS Regulations and additional guidance should be considered here. Changes to the definitions of the content categories should be made so that there is no need for a specific rule or definition involving "resale" of products. A PCC1 resource is properly defined by the simple geographic and scheduling options listed in the law, without additional reference to the transaction question of bundling or unbundling that is not listed in the law. With that definition, there is no need to distinguish between a "resale" transaction involving* *the sale of bundled energy and RECs from a resource already procured by an RPS-obligated entity and the simple selling of RECs from the resource. These RECs would still be PCC1 per the initial meeting of the PCC1 requirements under the law.*

The current interpretation allows an RPS obligated entity to "reuse" the RECs from a PCC1 transaction by banking them, and later associating them with other procured energy while still counting them as PCC1, but prohibits the RPS obligated entity from selling these same RECs without bundled energy as a PCC1 product. Such a distinction based on the ownership of the RECs is not apparent in the law and makes little if any sense in practice, serving only to complicate RPS implementation unnecessarily. It is a limitation on commercial transactions that can only serve to increase costs and threaten compliance for no perceivable policy benefit. The expected benefits from a PCC1 product have already been conveyed by the original procurement and scheduling structure.

Similarly for a PCC2 product, the initial procurement and scheduling of incremental substitute energy into California conveys the expected benefits of that product, so there should be no need to distinguish between the subsequent "resale" of both RECs and some other substitute energy from the sale of the PCC2 RECs themselves. There is no real market or policy benefit from this distinction. For a PCC3 product, in which the original procurement did not meet the criteria for PCC1 or 2, any resale cannot or will not convey any sense of meeting these criteria, and so still remains a PCC3 transaction.

The only exception to this structure of implementation is that grandfathered, or PCC0, procurement would likely be altered upon resale, either bundled or just RECs, to one of the three categories explicitly mentioned in the law. This is because PCC0 procurement is explicitly defined in the law as involving contracts signed prior to a specific date – June 1, 2010, and any resale contract for this energy and/or just RECs can be arguably interpreted as a new contract signed after that date. There is no such contract timing in the law for the other "categories" of procurement.

Note that there is still a "bright line" between categories in this simpler RPS construct – it is simply a line based on the initial procurement criteria found in the law, rather than the nature of the final procurement contract. This recommended "bright line" allows simpler implementation and verification of RPS compliance, as the CEC and CPUC could determine PCC categorization with the initial procurement, even by looking at the proposed criteria for the initial contract, rather than having to wait until the final procurement used as RECs are retired, and examining the contract path and structure that that procurement has acquired over time. In addition, this RPS construct does not discriminate against "out of state" procurement any more than the currently established construct. Out of state resources can be PCC1, 2 or 3 (or grandfathered) resources under the law, and under the proposed construct RECs that are subsequently sold from these resources can remain as PCC1, 2 or 3 resources, just as for resources located in-state that meet the product content criteria.

5. Contract Amendments and Excess Procurement

The Energy Commission is seeking input on whether the Energy Commission's regulations for POUs should address subtraction of short term contracts for purposes of excess procurement. Please consider and respond to the following issue and question.

Issue: Section 3206 (a)(1)(A) of the Energy Commission's regulations requires that electricity products procured under contracts of less than 10 years in duration be subtracted from the calculation of excess procurement, unless the electricity product is deemed "count in full." However, the regulations do not currently address how the term of the contract is calculated when the original contract term is amended. For example, if the term of the original contract is 7 years, and the contract is amended shortly before it ends to add an additional 5 years, should the term of the contract now be considered 12 years for purposes of calculating and subtracting excess procurement or should the 5-year addition be considered the term for calculating and subtracting excess procurement, since the duration of time from the amendment date to the end of the original contract is less than 10 years.

a. Should the regulations be clarified regarding the term of amended contracts for purposes of calculating and subtracting excess procurement? If so, how and why?

SMUD Response: *Yes, the regulations should be clarified to ensure that the common practice of amending contracts over time when beneficial to both contractual parties can continue without artificial constraints. Contracts of less than 10 years are disfavored by the law by virtue of being subtracted from any excess procurement calculations at the end of a compliance period. Of course, this likely has the intended effect of favoring terms of 10 years or more during consideration of new contracts, but leaves existing short term contracts orphaned unless they are either "count in full" or can be modified to be longer than 10 years in length or both.*

While the law is not explicit or clear on amendments to such contracts, the CEC may wish to avoid the situation where an entity signs up a new short term contract and later extends that contract to a longer length to avoid implications on the excess procurement calculation. However, this concept is moot for already existing short term contracts – there can be no incentive to engage in short-term then amended to long-term procurement from a historical perspective. When an entity has such a historical contract that is not a "count in full" contract, the only way to avoid a negative effect upon the excess procurement calculation is to reduce procurement so that there is no excess procurement to calculate. The CEC should not establish policy that has that negative implication.

Hence, SMUD suggests that the CEC include in the RPS Regulations and provide guidance indicating that historical short-term contracts (less than 10 years in term) that are amended to increase the term to 10 years or more in total be treated so that they do not affect the excess procurement calculations – similarly to new long-term contracts.

The previous CEC guidance on this issue for "count in full" short term contracts, originally posted in the summer of 2013 but subsequently removed, was found in question 31 and the CEC's answer from the "frequently asked questions" document:

> ***31. For the purposes of calculating excess procurement, if a contract that is less than 10 years in duration but meets the criteria of section 3202 (a)(2) of the regulations is extended, is the new contract length the total calculated from the original contract execution date, or is the new contract length the length of the extended term?***
>
> *If no other terms of the contract changed, the new contract length is equal to the duration between the original contract execution date and the new contract end date set by the amendment. If other terms of the contract (for example, substituting a different eligible renewable energy resource, adding a new eligible renewable energy resource, or increasing the nameplate capacity or expected quantities of annual generation) changed as a result of the amendment, then the new contract length is equal to the duration between the date of execution of the contract amendment and the new contract end date set by the amendment….*

This guidance was reasonable except for one aspect. The phrase "If no other terms of the contract changed…" implied that even administrative changes such as updating the contact information due to personnel changes on either side would not be allowed. This is commercially unreasonable. The CEC's regulations and/or guidance should delineate what changes to the contract would be sufficiently major to imply that the extended term of the contract is essentially a "new" contract with a "new" length or term that does not include the original term of the contract through the effective date of the amendment. Hence, changes such as the examples mentioned in the previous guidance – substituting a different renewable resource, or increasing the capacity or amount of generation under the amendment, could be considered as effectively a new contract, while changes that are not material would be considered an extension so that the revised contract includes the entire original term of the contract.

It does not make sense, in SMUD's mind, to consider any amendment of a short term contract as implying a "new" term from the effective date forward, while considering any amendment of a long-term contract as merely extending the existing term of the contract. Under such an interpretation, an entity could have a 10 year contract, extend it by one month in order to get more procurement in a compliance period, and have the entire procurement counted without impact on the excess procurement calculation. In contrast, an entity could have a 9.9 year contract and extend it for a second 9.9 years, implicitly fulfilling the intended favoring of long-term contracts, and yet have the procurement from the contract devalued by subtraction from the excess procurement calculation. Neither does it make sense to prohibit (by devaluing) any amendments of short-term contracts into longer term contracts whatsoever, unless the amended portion of the term is 10 years or greater -- this is an unnecessary and counterproductive restriction on commercial transactions.

Section 2: Generation from In-State DG Systems Should Be Classified as PCC1 Because In-State Systems Meet the Statutory Requirement for PCC1.

A. Topic 2: Generation from In-State DG Systems at RPS-certified facilities Should Be Classified as PCC 1 Because In-State Systems Meet the Statutory Requirement for PCC 1.

SMUD's urges the CEC to reconsider its classification of electricity generated by a DG system in California and consumed on-site as PCC 3, or Category 3. On balance, the legal and policy reasons to classify in-state DG as Category 1 outweigh the alternative interpretation reached previously by the Energy Commission, embodied in section 3203(a) of the *Enforcement* Procedures *for the Renewables Portfolio Standard (RPS) For Local Publicly Owned Electric Utilities* ("regulations").

First, the law explicitly imbues eligible resources, *including DG*, connected to the distribution grid with Category 1 attributes. (PUC section 399.16(b)(1).) The statutory language in subsection (b)(1) that defines a Category 1 product does not require bundled procurement of energy and RECs, whether or not the DG system is net metered. Second, section 399.16(b)(3) does not explicitly or implicitly modify subsection (b)(1) to remove the portfolio content category attribute it conveys to in-state renewables. Subsection (b)(3) is a residual category of electricity products that do not meet the definitions of subsections (b)(1) and (b)(2). Third, the distinction in the definition of a Category 3 product between bundling and unbundling is material to the question of who owns the REC, not which attributes the REC carries. This is consistent with PUC section 2827(h). That section does not support a reading of the statute that electricity generation consumed on-site, which in some transactions is procured unbundled, *must* be classified as Category 3. There are other policy and practical reasons to change paths here as well.

In addition, CPUC precedent is not binding upon the Energy Commission. While the CPUC in Decision 11-12-056 viewed on-site load as inherently Category 3, there are several reasonable interpretations of the statute and the CPUC's judgment is only one view. SMUD urges the CEC to see another reasonable perspective, just as valid, that the "including unbundled RECs" language of (b)(3) does not mean all unbundled RECs must be Category 3, but rather unbundled RECs are a subset of RECs that do not qualify under the criteria of paragraph (1) or (2). Viewing unbundled RECs as a subset of Category 3 products rather than the complete universe of Category 3 products, would enable the Energy Commission to make a policy choice that will enable SMUD and other distribution utilities to foster more local renewable generation on the distribution grid. This interpretation is the superior policy choice because it furthers the goals of California's RPS law in a way that creates a more stable electric grid. In our following comments, SMUD will first discuss why the statute has more flexibility than previously thought.

1. Pub. Util. Code Section 399.16(b)(1) explicitly imbues eligible resources, *including DG*, connected to the distribution grid with Category 1 attributes.

The RPS law defines Category 1 resources, and their attributes, to:

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source or dynamically scheduled

If the eligible renewable energy resources meets any of the four conditions of (b)(1), then by statute it is a Category 1 resource. Thus, an eligible renewable energy resource, including distributed solar generation, having its “first point of interconnection with distribution facilities used to serve end users in a California balancing authority”, is by definition a Category 1 resource. Obviously, the Legislature intended to include distributed solar generation as a Category 1 resource or it would never have provided for the criteria of interconnection with a utility’s distribution facilities. Re-classifying large proportions of generation from Category 1 would appear to be inconsistent with that intent. In any event, when an eligible resource so interconnected generates electricity it has the attribute of Category 1.

There is nothing in this statutory language about bundling or unbundling. The words simply do not appear in subsection 399.16(b)(1). Those words are not a condition, implied or otherwise, for distributed solar generation interconnected with distribution facilities to be classified as Category 1. The expressed purpose of the Legislature in subsection (b)(1) is that the eligible renewable energy resource be interconnected with distribution facilities used to serve end users within a California balancing authority area. That is satisfied by in-state distributed solar generation, whether the connection with the distribution grid is net energy metered or is sold to the utility through a power purchase agreement (PPA).

The standard rules of statutory construction require that the plain meaning of words of a law be honored, but leave room for using the law’s purpose, legislative history, and public policy considerations if there is ambiguity.[1] There is no ambiguity here, that the plain meaning of paragraph (b)(1) is that distributed solar generation is a Category 1 resource whose RECs bear a Category 1 attribute.

[1] Imperial Merchant Services, Inc. v. Hunt (2009) 47 Cal. 4th 381, 387-388. (“... look to the statute's words and give them their usual and ordinary meaning. The statute's plain meaning controls the court's interpretation unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy. . . .”)

2. Section 399.16(b)(3) does not explicitly or implicitly modify subsection (b)(1) to remove the portfolio content category attribute it conveys to in-state renewables.

The statute defines Category 3 resources, and their attributes, as a residual category of resources that do not fall within Categories 1 and 2:

> 399.16(b)(3): Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, **that do not qualify under the criteria of paragraph (1) or (2). (emphasis added)**

The existing Regulations, on the other hand, define Category 3 resources somewhat differently as:

> (c) Portfolio Content Category 3
>
> > (1) All unbundled renewable energy credits and other electricity products procured from eligible renewable energy resources located within the WECC transmission grid that do not meet the requirements of either Portfolio Content Category 1 or Portfolio Content Category 2 fall within Portfolio Content Category 3.

In the first place, the Regulations change the statutory definition of Category 3 resources by changing the text of the statute. Where the statute says "*including* unbundled renewable energy credits", the Regulations read "*All* unbundled energy credits", and then place this re-written phrase at the beginning of the definition, rather than in the subordinate clause found in the statute. In addition, the Regulations add the word "other" in front of "electricity products", cementing the change that eliminates the reasonable construction that some "unbundled energy credits" can meet the requirements of Categories 1 or 2.

The usual and ordinary meaning of a phrase that starts with the word "including …" is that there exists a subset of things identified in the dominant clause that are being referenced in the subordinate clause.[2] "Including" means "an example" or a "part of a group or as a part of something".[3] The plain meaning of including does not mean "all" or "exclusively". There is no ambiguity about this phrase that should somehow convert a word that means a "part of" into "all of". SMUD has found no recognized authority that

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[2] This convention is used by the Legislature throughout California statutes. See PUC section 2827(i)(3) ("Any net credit to the eligible customer-generator of electricity costs may be carried forward to subsequent billing periods, provided that a local publicly owned electric utility may choose to carry the credit over as a kilowatt hour credit consistent with the provisions of any applicable contract or tariff, including any differences attributable to the time of generation of the electricity.

[3] Including is a preposition, defined as "Containing as part of the whole being considered." Example phrase, "languages including Welsh, Cornish, and Breton." Oxford Dictionaries on-line. According to Merriam-Webster on-line dictionary, "include" means "to have (someone or something) as part of a group or total: to contain (someone or something) in a group or as a part of something."

defines "including" to mean "all" or "exclusively".

The Regulations also read out the last clause of paragraph (b)(3). The phrase "that do not qualify under the criteria of paragraph (1) or (2)" plainly relegates those eligible renewable energy resources "that do not qualify" under (b)(1) to Category 3. If a resource does qualify under (b)(1) then it does not fit within the residual (b)(3) category. The statutory construction of paragraph (b)(3) contained in the Regulations is not a usual and ordinary meaning of the phrase "that do not qualify under the criteria of paragraph (1) or (2)" because it simply ignores that phrase. California law requires that when a statute has potentially conflicting forms of construction, preference is given to the interpretation giving effect to the entire statue, rather than an interpretation "which would destroy any portion of it and to that extent defeat the legislative intent."[4] Reading out a portion of the statutory text necessarily destroys it and in this case defeats the legislative intent to classify distributed resources as Category 1. The proper reading of (b)(3) gives full weight to what is really the main defining characteristic of Category 3 – electricity products that: "… **do not qualify under the criteria of paragraph (1) or (2)**."

The Final Statement of Reasons (FSOR) published by the Energy Commission, as required by law, attempts to explain the Energy Commission's de-construction of paragraphs (b)(1) and (b)(3). In response to numerous comments on this issue by SMUD, CMUA, and others, the Energy Commission wrote:

> Bundled products are required for PCC 1 and PCC 2, because PCC 3 in statute is defined to include unbundled RECs. PCC 1 and PCC 2 must exclude unbundled RECs to remain distinct categories and avoid a situation in which a REC could be classified in more than one PCC. In order for a REC to be considered bundled, it must be procured bundled by the POU retiring the REC. Regarding statutory construction, Public Utilities Code section 399.16(b)(3) defines PCC 3 as "eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraphs (1) and (2) [i.e., PCCs 1 and 2]." The phrase "including renewable energy credits" would be incongruous if it were intended by the Legislature as an example of a type of electricity product that could be counted as PCC 3. Neither PCC1 nor PCC 2 include examples, and using the phrase "including unbundled renewable energy credits" to mean anything other than "including **<u>all</u>** unbundled renewable energy credits" would render the inclusion of the phrase pointless.
>
> In addition, while the legislative history of the SBX1-2 specifically refers to unbundled RECs associated with eligible renewable energy resources located outside a California balancing authority, as CMUA indicates in its comments, the language of the statute itself does not evidence desire by the Legislature to limit the application of PCC 3 to just unbundled RECs from resources located outside

[4] See Cal. Civil Code § 354 L("An interpretation which gives effect is preferred to one which makes void."); and Fay v. Dist. Ct. of Appeal, Second Appellate Dist., Division 2 (1927) 200 Cal. 522, 896.

a California balancing authority. Had the Legislature wanted to treat unbundled RECs from resources located within a California balancing authority differently from resources located outside a California balancing authority it could have explicitly stated so in SBX1-2.

Likewise the language of the statute does not evince a desire by the Legislature to limit the application of PCC 1 to just bundled RECs. Had the Legislature wanted to exclude unbundled RECs from eligible renewable energy resources having its first point of interconnection with distribution facilities used to serve end users within a California balancing authority area it could have explicitly said so in paragraphs (b)(1) and (b)(2). It expressly included unbundled RECs in Category 3 only if the renewable resource does "not qualify under the criteria of paragraph (1) or (2)". It also expressly did not state in paragraph (3) that all unbundled RECs are Category 3.

At the heart of the Energy Commission's statutory construction that all unbundled RECs are Category 3 is not what the Legislature said in SBX 1 2 but the assertion that the phrase "including unbundled renewable energy credits" would be "incongruous" if the Legislature meant "including" in the sense of an example of a type of electricity product. The incongruity that the FSOR refers to is an absence of symmetry between paragraph (b)(3) and paragraphs (1) and (2). Because paragraphs (1) and (2) do not "include examples"[5] of types of electricity products, the Legislature could not have meant unbundled RECs as an example of a type of Category 3 product. In other words, in order to read "including" in its usual and ordinary sense in paragraph (3) the Legislature should have added examples in other parts of 399.16(b). According to this theory of statutory construction, the Legislature is not free to provide an example of what it means in one of three categories without providing examples in the other two. However, the Legislature is not so constrained. It is certainly free to emphasize that unbundled RECs, among other electricity products, should be classified as Category 3 if they do not qualify under the criteria of paragraphs (1) and (2). It is certainly free to provide an example of a PCC and not give examples of all kinds of categories. It is unreasonable to surmise that the Legislature could not have meant to give the word "including" its usual and ordinary meaning because it didn't use it elsewhere in the statute.

Nor does the objection made in passing in the FSOR, that PCC 1 and PCC 2 must exclude unbundled RECs to remain distinct categories, hold because unbundled RECs can be distinctly classified in Category 1 or 2 if they qualify under the criteria of either category. Thus, an unbundled REC procured from a Nevada distributed solar system would not be classified in Category 1 because the facility is not connected to the distribution facilities of a California balancing authority.

As SMUD has said before, there are other examples of unbundled resources that retain their Category 1 classification despite unbundling. For example, when a utility procures Category 1 RECs, banks them, and carries them forward from one compliance period to the next, these RECs are unbundled from the underlying generation. When the banked

[5] Tellingly, the FSOR uses the word "include" in its usual and customary way, as an example of a part of a group.

RECs are associated with subsequent or substitute energy in the compliance period when claimed for compliance, they do not lose their Category 1 compliance status. No one in these proceedings has suggested that this unbundling removes the Category 1 attribute. Also, when a Category 1 resource generates within California, but is procured by an entity that cannot get transmission from the eligible resource to its load, the generation is sold into the ISO market or a similar market, and the RECs from the unconnected resource are associated with other energy purchased to serve load. Again, no one suggests that this "within-the-state-market-transaction" unbundling removes the Category 1 attribute. In both cases the procuring entity keeps the REC, although the REC is unbundled from the underlying energy. There is nothing in the statutory definition of a REC that supports the proposed policy that an unbundled REC keeps its Category 1 attribute if retained for compliance by the initial procuring entity, but loses that attribute if resold by that entity and used for another entity's compliance. There is no ambiguity in the definition of a REC that allows or supports this interpretation.

3. The distinction between bundling and unbundling is material to the question of who owns the REC, and does not change the attributes that the REC carries.

The discussion of Topic 2 in Attachment A states that electricity generation consumed on-site is unbundled and classified as PCC 3, and is consistent with the net-energy metering provisions of Pub. Util. Code section 2827(h). However, the discussion takes a leap of logic that section 2827(h) supports the notion that electricity generation consumed on-site is necessarily PCC 3.

As Attachment A points out, the net-energy metering provisions of section 2827(h)(6)(A) state that RECs associated with electricity generated and utilized by the customer-generator shall remain the property of the customer-generator. The statute thereby addresses the question of ownership of the REC. However, it says nothing about what attributes the REC carries. The issue of who owns the attributes is a different one from what they are, and section 2827(h) says nothing about what they are.

Nevertheless, staff is using section 2827(h) to make an argument that statutory mandate about ownership of the REC somehow changes its attributes. In other words, ownership changes the nature of the thing generated – from a PCC 1 REC with high value to a PCC 3 REC with a lower value. SMUD does not believe that this is what the Legislature meant to express with this part of the net-energy metering law. SMUD believes that the Legislature meant to address who gets the value of the REC, not what it should be.[6]

[6] This language, now codified in Section 2827(h)(6)(A), was added by AB 920 in 2009, after the CPUC ruled that RECs associated with electricity generation consumed on-site belonged to the facility owner. The Legislature in effect codified the CPUC's ruling. This happened before the PCCs were added to the RPS laws.

The value of the eligible renewable energy resource electricity product is determined by the kind and location of the resource that made it. That is evident in section 399.16, which created the portfolio content categories after section 2827(h)(6)(A) was enacted.

Paragraph (b) of section 399.16 provides in part:

> (b) Consistent with the goals of procuring the least-cost and best-fit electricity products … and that provide the benefits set forth in Section 399.11, a balanced portfolio of eligible renewable energy resources shall be procured consisting of the following portfolio content categories:

The benefits set forth in section 399.11 are numerous, but among them are:

> (b)(1) Displacing fossil fuel consumption within the state.
> (2) Adding new electrical generating facilities in the transmission network within the Western Electricity Coordinating Council service area.
> (3) Reducing air pollution in the state.
> (4) Meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation.
> (5) Promoting stable retail rates for electric service.
> (6) Meeting the state's need for a diversified and balanced energy generation portfolio.

Thus, the Legislature intended for the portfolio content categories created in that section to be differentiated, in part, by their benefits to the grid. In the case of customer-owned DG, there no rational basis to differentiate between the benefits of the electricity generated by the DG system that is consumed on site as compared to net surplus generation fed to the distribution grid. Both displace fossil fuel consumption with California to the same degree. (b)(1) Neither add new electrical generating facilities to the transmission network in the WECC. (b)(2) Both reduce air pollution in the state to the same degree. (b)(3) Both meet the state climate change goals by generating electricity from resources that emit no GHGs. (b)(4) Arguably, net surplus DG may do less to promote stable retail rates because of its high cost, but this impact would likely be minimal and hard to quantify. (b)(5) And certainly, it’s the existence of the DG system itself that promotes the state’s need for a diversified and balanced energy generation portfolio, not whether it generates a surplus. (b)(6)

It is these benefits that the Legislature was trying to achieve by differentiating electricity products into the portfolio content categories, and whether the DG from a California solar PV facility is consumed on-site or fed into the distribution grid makes no difference. The same benefits enumerated in section 399.11 are achieved as long as the DG system is connected to the distribution facilities of a California balancing area, as stated plainly by the Legislature in paragraph (b)(1)(A). It is the consumption of the electricity from the DG system in California that determines these benefits, and thus should determine its attributes. If the DG system were located outside of California (and in the WECC), and a California utility were to buy those RECs for RPS compliance, then it's easy to see why those RECs (bearing fundamentally less valuable attributes) should be relegated to PCC 3 because few of the benefits valued by the Legislature would be carried by those RECs. But that is not the case with in-state DG connected to the distribution grid. This fact has been wholly overlooked in the logic of equating PCC 3 value with unbundled RECs from California DG facilities.

Section 3: Additional Regulatory Modifications for Consideration

Again, although the July 11th workshop notice limited consideration of changes to the RPS Regulations to the 5 general topics listed, SMUD believes that other regulatory changes should be considered. The RPS Regulations are newly minted, adopted just one year ago with no subsequent amendments to date. There has been limited experience under the RPS Regulations to date but that experience should be brought into the picture for potential amendments from the perspective of the obligated parties, not just through a CEC workshop notice. CEC staff had previously suggested that a general "Scoping Workshop" to elicit public opinion about necessary regulatory amendments would be held, similar to that held in January to elicit opinion about potential changes to the RPS Eligibility Guidebook. SMUD provides a few comments outside of the 5 topics below, expecting that these recommended changes can be considered to be helping to identify the "scope" of potential changes to the RPS Regulations.

First, SMUD recommends that the CEC consider changes in Section 3202 with respect to the restrictions on procurement of RECs for a prior compliance period. Section 3202(e) states that a POU cannot "procure" RECs for a compliance period, if that procurement occurs after the end of the compliance period. Added near the end of the regulatory process for the initial regulations, it seems clear that this provision did not receive adequate stakeholder discussion or CEC consideration. There is no legal requirement preventing such procurement, nor is there any policy reason to prohibit a POU from purchasing additional RECs for a compliance period after the end of the period but prior to their compliance filing.

In practice, a POU does not know with certainty the final RPS obligation nor the final amount of procurement it has toward that obligation until several months after the end of the compliance period (neither retail sales nor the amount of RECs procured is known on December 31st at the end year of a compliance period). It is eminently reasonable to allow a POU to take stock of its compliance status with complete information – a few months after the end of a compliance period – and "true up" with the purchase of additional RECs if necessary.

Second, SMUD believes that the CEC should strive to reduce duplication between the RPS Regulations and the RPS Guidebook, and to favor inclusion in the RPS Guidebook where appropriate rather than in the RPS Regulations – due to the inherent flexibility of the RPS Guidebook. For example, again near the end of the regulatory process for the initial RPS Regulations, wording added to Section 3203(a)(1)(C) included in the regulations the need to have an “hourly” comparison between the metered generation of a facility and the amount of electricity scheduled in each hour into a California balancing authority, with the lesser amount considered PCC1 under the regulations. However, this hourly requirement is also in the RPS Guidebook, and SMUD suggests that the text be removed from the RPS Regulations. SMUD has argued that the hourly “lesser of” calculation is not necessary nor required and has negative market implications, and has suggested that leaving the language in the RPS Guidebook would make it easier for market experience and impacts to lead to consideration of changes to this practice.

Third, SMUD again questions the usefulness of Section 3202(a)(3). This portion of the regulations conceptually captures the unique cases of resources that would be “count in full” by virtue of a signed contract prior to June 1, 2010, but are not afforded that status due to the fact that they did not meet the RPS eligibility requirements established by the CEC at the time of signing. Per the regulations, these resources must be categorized into PCC1, 2, or 3, but will not be included in the portfolio balance requirements that apply to those categories. In essence this provides these resources with “exalted” “count in full” status. For purposes of compliance they are treated exactly like “count in full” resources, except that unlike “count in full” resources, modifications of the underlying contracts has no impact whatsoever on the categorization of the resources. And, the categorization of the resources in to PCC 1, 2 or 3 has no material impact on the RPS (e.g. not counted toward the PCC1 minimum nor the PCC3 maximum), other than to make reporting, retirement, and compliance more complicated. For example, while the CEC expects WREGIS retirement into categorical subaccounts, there is none established or expected for these resources (nor would the additional complication of doing so be useful – it just clutters up the retirement process). SMUD recommends deletion of Section 3202(a)(3) and consideration of these resources as PCC0 resources, because they impact compliance under the RPS nearly indistinguishably from these much more numerous resources.

Other aspects of the RPS Regulations surely could be considered for modification with a more robust scoping process, and SMUD encourages the CEC to allow such additional scope at the beginning of this rulemaking.

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Thank you again for the opportunity to comment.

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cc: Corporate Files {LEG 2014-0626}