COMMITTEE HEARING

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

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	)

Staff Workshop on Proposed Lighting
Efficiency Measures for Residential and
Nonresidential Buildings

CALIFORNIA ENERGY COMMISSION
HEARING ROOM B
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

FRIDAY, July 11, 2014

9:34 A.M.

REPORTED BY:
Peter Petty

APPEARANCES

Commissioners

David Hochschild

Emilio Camacho, His Advisor

Gabriel Taylor, His Advisor

CEC Staff Present

Kate Zocchetti

Emily Chisolm

Angie Gould

Gabriel Herrera

Theresa Daniels (Via Telephone)

Brian McCullough (Via Telephone

Also Present

Public Comment

Andy Schwartz, Alliance for Solar Choice (SolarCity)

Don Ouchley, Merced Irrigation District (MID)

Justin Wynne, MID

Linda Johnson, Small POUs

John Pappas, PG&E

Antonio Goncalves, City of Roseville, California

William Westerfield, SMUD

Walker Wright, Sunrun

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P R O C E E D I N G S

JULY 11, 2014 9:34 A.M.

MS. ZOCCHETTI: Good morning, happy Friday to everyone. I'm Kate Zocchetti. I'm the Office Manager of the Renewable Energy Office here at the Energy Commission.

Before we have introductions, I'd like to just go over the agenda, briefly, and then some housekeeping.

We'll have a little slide about how you can participate in today's workshop, welcome and opening remarks from Commissioner Hochschild.

The purpose of our workshop today, then we will give a short staff presentation, followed by the opportunity for public comments. And we'll talk about how that happens. And then we'll go into next steps.

You can find handouts of today's presentation, and also the workshop notice, and Attachment A on the front desk.

The restrooms are located right outside these main doors and to the left.

We have a snack bar on the second floor. We don't think we'll go into the afternoon, but if we do we will break for lunch, and there are local restaurants within walking distance.

The emergency evacuation procedures, if you hear a bell, see flashing lights please following staff out the main doors here and we'll convene at the park kiddie-corner here.

And please remain orderly and follow traffic lights, and wait there until you get the okay to come back in.

We are on WebEx today and today's workshop is being recorded.

We will have our presentation from today posted on our website probably next week.

To participate in today's workshop, if you are here in person and you'd like to comment, please fill out a blue card that's located on the desk when you came in, and give it to one of the staff members.

If you're on WebEx, we will take your comments by using the little "raise hand" function or you can type in your question to our WebEx folks here in the room.

We will also have opportunities to comment via phone. All the phones are muted at this time. Please mute your own phone, as well, and only unmute it when you want to ask a question.

We will be taking written comments up until July 28th, and those instructions will be provided later.

So, at this time I'd like to introduce my colleagues. Emily Chisolm is closest on the desk here. Angie Gould, who is just back from maternity leave, congratulations Angie, so she's trying to get up to speed, again.

And Gabe Herrera, our staff counsel.

And on our WebEx is Theresa Daniels and Brian McCullough.

And I'd like to introduce Commissioner Hochschild and his advisors.

And, Commissioner Hochschild, would you like to have some opening remarks?

COMMISSIONER HOCHSCHILD: Sure, thank you, Kate, and good morning and welcome to everybody.

For those of you who were there on Monday, at the Intersolar Conference, we had -- Governor Brown gave a spectacular speech on sort of the vision for the future and for solar in California. And it was very inspiring.

And so, part of this workshop is really to make sure, as we're proceeding down the RPS path that we have the regs where they need to be.

It's a very difficult choice, obviously. Every time you make a change, there's a lot of ramifications for that.

So, we're going to stay as long as it takes to hear everybody’s views on this today. I want to really dig as deep as we can.

And, actually, for my benefit if I could ask if we could do a quick round of introductions for the people who are in the room? Just quickly just say your name and your organization.

And when we come to staff, if you can also just say, again, your area of responsibility so people know what you’re doing.

So, if we could just do that quickly. Walker, maybe we could just start with you.

(Whereupon, the audience introduces themselves off the record)

COMMISSIONER HOCHSCHILD: I’d like to add, the people who introduced yourself, can you please drop a business card off with the court reporter at some point during the day, just to make his job a little easier.

MS. CHISOLM: I’m Emily Chisolm, I’m over POU compliance.

MS. GOULD: Angie Gould, POU compliance and verification.

MR. HERRERA: Gabe Herrera with the Energy Commission’s Legal Office. I provide advice to the Commission on the RPS implementation, including POU regs.

MR. CAMACHO: So, Emilio Camacho. I'm advisor to Commissioner Hochschild.

MR. TAYLOR: And Gabriel Taylor, advisor also to Commissioner Hochschild.

COMMISSIONER HOCHSCHILD: Great, okay, thanks everybody and welcome.

Take it away, Kate.

MS. ZOCCHETTI: Thank you. Again, I'd like to remind everyone, if you do have comments today, when we get to that portion you can give your business card to the court reporter and also announce yourself at the podium so that the folks on WebEx and on the phone can know who's speaking.

And at this time I'd like to invite Emily Chisolm to come up and provide the staff presentation. Thank you.

MS. CHISOLM: Hi everyone. So, first is the purpose of the workshop. Today we will introduce the proposed scope of amendments and issues identified to date, a preliminary schedule for adoption of the amendments to the regulations.

And we will be soliciting initial comments from stakeholders regarding the scope of amendments and options for addressing issues.

A little recent legislative background, the 33-

percent RPS was established by SB X12, in 2011. And the Energy Commission adopted implementing regulation in June of 2013, which were effective in October of 2013.

The RPS was revised by Senate Bill 591 in 2013, by adding an exemption for a POU that receives at least 50 percent of its retail sales from qualifying hydro.

The topics for amendments are implementing Senate Bill 591; clarifying the portfolio content category for POU-owned or procured DG systems; clarifying the definition of retail sales; clarifying the meaning of resale, clarifying the subtraction of generation under amended contracts less than 10 years for purposes of excess procurement; and hourly data for dynamic transfer agreements.

Topic one is implementing Senate Bill 591. SB 591 exempts a POU that receives greater than 50 percent of its retail sales from its own hydro-electric generation, and excuses the POU from having to procure additional renewables in excess of either the portion of the POU’s retail sales not supplied by its own qualifying hydro-electric generation, or the POU’s adopted cost limitation.

The first set of questions is how to qualify for the exemption. When should 50 percent of retail sales be calculated and when should the POU report info on qualifying conditions?

The second set of the questions are for how the exemption will be applied.

Should the RPS target be based on a POU's total retail sales or remaining retail sales not met by qualifying hydro?

Should the portfolio balance requirements be applied?

Should the RPS requirements be annual or based on a compliance period?

And how should the Energy Commission verify the RPS exemption is being applied correctly?

Topic two is the portfolio content category for POU-owned or procured distributed generation.

Should the generation from a DG system at an RPS-certified facility, be classed as PCC-1 if the system is POU owned or a POU procures bundled electricity generation from the system owner?

Does it matter if the procured generation is measured behind the meter?

If generation is used on site, is it available to be procured by a POU?

Does it violate section 302(a)(1) if the POU procures a bundled product and sells electricity to the system owner?

Should the rules change if a third party owns or installs the DG system?

And could a facility do net metering if a POU procures bundled electricity and sells electricity to the system owner?

Topic three is the definition of retail sales. Should the definition of retail sales be clarified to properly exclude POUs' consumptive load?

And if so, how can consumptive demand be differentiated from retail sales?

We do have the current definition for retail sales there for anyone who hasn't memorized it.

And the definition of resale is topic four. Should resale be defined in the regulations?

We currently have a definition in our frequently asked questions that says a resale is a POU purchase from another RPS-obligated entity.

Topic five is contract amendments and excess procurement. Should the regulations address the term of amended contracts for calculating excess procurement?

Considering that section 3206(a)(1)(a) requires subtraction of generation under contracts less than 10 years from excess procurement, unless the contract is counted full, how should contracts be treated for excess procurement if amended to lengthen the contract term?

And the last topic, 6, dynamic transfer agreements. There are two types of dynamic transfers, dynamically scheduled and pseudo-ties.

Because the electricity products under a dynamically scheduled agreement are not necessarily scheduled into a CBA, we are asking should the Energy Commission verify dynamic schedules on an hourly basis?

Oh, sorry, okay. Next we have the Energy Commission's preliminary schedule. The first four dates there are the current workshop and the comment period that are happening right now.

And then the next set of dates, kind of the bottom half, those are dates associated with the formal rulemaking beginning with the notice of proposed action and then they are all tentative.

All right, short and sweet, we are now into public comments. And maybe I'll switch places with Kate.

MS. ZOCCHETTI: So, of course, you can continue to provide blue cards if something comes up and you want to comment here, at the workshop.

I am taking these in no particular order. Andy Schwartz.

And I should just clarify that we aren't taking any topic in any particular order. We didn't want to have people coming up and back, and up and back for each topic. So, we thought we do the whole presentation and then topics are whatever you care to comment on.

MR. SCHWARTZ: Great. Commissioner and Commissioner’s staff, thank you for the opportunity to speak today.

So, I’m here on -- my name is Andy Schwartz. I’m here on behalf of the Alliance for Solar Choice.

The Alliance is a membership organization comprised of the leading solar installers in the country, comprising the vast majority of installations that are going in today.

I’m here to speak on, I guess it’s question number two, primarily, related to the portfolio content category designations.

So, I think I can keep my comments fairly brief. We’ll provide more detailed feedback, on the questions that were asked, in our written comments.

So, the Alliance for Solar Choice, or TASC, does support the categorization of RECs that are sold to utilities from behind-the-meter facilities as portfolio content category one.

We believe that from the stand point of public policy it’s unequivocal that these systems provide -- fulfill all of the objections that the RPS program was intended to achieve.

And for those reasons, you know, again, from the perspective of public policy, do not see a sound basis for merit and categorizing them in a way that’s sort of -- that significantly diminishes their value.

These resources are located in-State, are clearly delivering energy to end-use customers in California, and provide the full spectrum of economic development, environmental reliability and hedging benefits that have motivated the RPS program.

The characterization of RECs associated with these facilities as portfolio consent category three dramatically reduces the value of these resources, both in economic terms, given the dramatically lower value associated with that portfolio content category, and in terms of their ability for -- they’re ability to facilitate utility achievement of RPS goals at reduced costs by increasing the number of compliance options that those utilities have.

Furthermore, as State and local incentives went down, as we looked to schedule reductions in the ITC, potential adverse outcomes of the Federal Trade Case involving solar, and rate design changes were implemented, as well as net energy metering looked at the value of renewable energy credits and facilitating ongoing deployment. And the sustainable solar industry becomes that much more important.

Again, for these reasons we support any movement that would allow these resources to be treated as portfolio content category one.

One other note that I would like to point out is that a number of states do allow RECs associated with customer-side of the metered DG facilities to fully participate and contribute to their respective RPS programs.

For example, Colorado, Massachusetts, New Jersey, Maryland, Ohio, Delaware and Pennsylvania are among the states that do not place limits, to my knowledge, or otherwise institute differentiated policies that adversely affect the value and ability of RECs to be used for RPS compliance purposes.

In fact, in a number of cases, RECs associated with solar, whether DG or otherwise, actually hold enhanced status within those programs.

California appears somewhat unique in establishing a rule that effectively regulates the customer-side-of-the-meter generation and the RECs produced to these systems to what’s essentially second-class citizen status within the regulatory regime.

So, as I said, we’ll provide more detailed comments on the specific questions that were asked, but I'm happy to take any questions now.

MR. HERRERA: So, Andy, I've got a quick question for you --

MR. SCHWARTZ: Sure.

MR. HERRERA: -- and maybe, actually, longer.

So, is there a need to distinguish between certain types of behind-the-meter DG?

For example, if it's owned by a utility, owned by a customer? That's the first part of my question.

And the second part is, if we do allow that categorized as PCC-1, how do you guard against situations where you have existing load behind the meter being served by on-site renewable generation?

And now, categorizing that as a PCC-1, rather than a PCC-3 in the case, for example, where you have the generator, again supplying some of his on-site load, now entering into a PPA to sell all the power to a utility and then immediately buying back that portion needed for on-site load?

I mean, should we be concerned about that?

MR. SCHWARTZ: Well, you know, I think there is a distinction to be made between RECs that are unbundled from wholesale energy and RECs that are unbundled from retail energy that's been used for end-use consumption.

In the case of customer-side systems, all of the energy from that system is being delivered and consumed on site.

And maybe this is different from the scenario that you laid out. But in general for the systems, for example that SolarCity is deploying, and most of TASC’s members are deploying and all the energy is being consumed on site.

So, it’s a retail -- it’s essentially a retail use of that energy.

It served kind of that final purpose, which is distinct from a wholesale transaction where you have a wholesale generator selling energy and RECs to a utility, the utility immediately turning around and selling that energy back for resale in the wholesale market.

And so I think there’s probably some light that can be built between RECs being unbundled from -- or from energy being used for final retail consumption purposes versus RECs being unbundled from a wholesale transaction.

In terms of the specific scenario, kind of the buy/sell back arrangement, you know, again, from a policy stand point if those facilities are achieving all of the goals that the RPS was intended to achieve, then

I don’t think a distinction should be made.

You know, the final -- we could keep in mind the final objectives or the ultimate objectives of that program which is, you know, hedging value, resource diversification that would provide the hedging value and environmental benefits, job creation benefits.

And there should be efforts made to interpret and implement a policy that facilitates those objectives.

So, I guess in the scenario you’ve described, I don’t know, as long as the facility is delivering energy to final -- to its retail customers in California, I guess I don’t know if there’s a major concern to be addressed.

MR. HERRERA: Thanks.

MR. SCHWARTZ: Sure. Thank you.

MS. ZOCCHETTI: Thank you, Andy.

Next is Don Duchley (sic).

MR. OUCHLEY: It’s actually Don Ouchley. I know it’s a --

MS. ZOCCHETTI: I apologize, sorry.

MR. OUCHLEY: That’s okay. Good morning Commissioner and Commission staff.

My name is Don Ouchley and I’m the Deputy General Manager of Energy Resources at Merced Irrigation

District.

We really appreciate the opportunity to be here this morning to discuss Senate Bill 591 and how it will be implemented by the Commission.

I'd like to provide kind of an overview of this legislation and our organization so you can understand the background behind Senate Bill 591.

Merced Irrigation District has a long history of delivering water, for irrigation purposes, to the San Joaquin Valley.

More recently, in 1997 the District decided to get into the electric distribution business in order to benefit the ratepayers in our area and provide them affordable electric energy.

We're a very small utility. We only have 8,000 customers, a combination of commercial and business customers.

And to put that in perspective, that's three-tens of one percent of the total electric customers in California.

We're not only a small utility, but we're a new utility. As I said, we got into business in 1997. We issued bonds back that time. We had a business plan. Incidentally, those bonds are still outstanding.

And we had a plan to grow the utility to be able to pay the debt and at the same time provide our customers with affordable energy.

We represent a very rural and extremely disadvantaged community.

The authors of Senate Bill 591 actually recognized that.

We're in the San Joaquin Valley, with a large minority population.

By just about any metric that you use, our community struggles. You can look at our unemployment levels, the economic development, whatever you want to use, we're at the bottom.

Even in the best of times our area is near the bottom of the scale in the economics.

We do serve the public that we do serve with affordable power. Twenty-six percent of the residents are below the Federal poverty level in our area.

And the median income of the residents there is approximately half of the State average.

So, I think you get the picture about our situation in the San Joaquin Valley, in our service area.

The other thing I'd like to point out is we're rather unique as an electric utility provider because our entire service area is overlapped with another service provider which means that on any day, any time our customers can go to the other provider. We compete every day for every customer that we have.

The benefits of our service, we're a public-owned utility. We're not a private corporation. We don't have investors. It's all to benefit the people that are in our community.

And Senate Bill 591, as I said before, was put together and passed for that purpose.

We are committed to renewable energy. The fact is, though, that we have some special circumstances in our area and the Legislature, once again, recognized that.

The special circumstances related to the economic conditions in our area are almost a unique factor in looking at the formulation of Senate Bill 591.

Our hydroelectric facilities that were built in the late 60's, and we had a long-term contract with an investor-owned utility to purchase the output. That contract terminated on June the 30th at this year. And at this time, the 1st of July, the first of this year we've taken over the complete operation, the benefits, and the expenses of that facility.

At certain times that hydro facility generates more power than our retail load. At other times it generates less.

And you might imagine, this year it's generating less because of the water situation.

And we have no intent to undermine the RPS program as it's laid out. But what we don't want to do is place an extra burden on our customers at this time, whenever the economics are so bad.

We're very proud of the fact that we've supported renewable resources. And, in fact, we were the very first sponsor with the University of California's Solar Institute, and we work right with them every day. Their research facility is one of our customers and we're working with them to improve the technology of solar. And that will be a benefit to the RPS effort, also.

I do understand that there's questions about how SB 591 should be implemented. Obviously, there's questions.

What you should not question is that the Legislature had specific intent to assist some of these most disadvantaged people that we serve, and without passing unburdened cost onto them.

The State Legislature understood the challenges faced by our customers and as well as the other side of the story, the situation that we're in.

Had they not, we wouldn't all be here today talking about Senate Bill 591.

Any questions?

COMMISSIONER HOCHSCHILD: No, thank you.

MS. ZOCCHETTI: Thank you very much.

Next is Justin Wynne.

MR. WYNNE: Good morning. My name's Justin Wynne. I'm also speaking on behalf of the Merced Irrigation District.

And we are going to provide much more detailed comments in our written comments, but I just wanted to give a couple of initial responses to the questions in Attachment A.

But I just wanted to reiterate one of the points that Don had made. This wasn't -- SB 591 wasn't just about a utility that had a lot of large hydro resources. The discussion at the Legislature, the an analysis always mentioned the extreme economic conditions that they have in their service territory.

And so the goal isn't just to address the unique situation of the hydro, it's also to protect their community from rate hikes, and then also to protect the industry in the local area to ensure that the economic conditions can improve.

Just as we're going through the process of implementing the bill, I think it may make sense in some circumstances to look at the rationale or the actual regulatory language that was used in the previous rulemaking, where there were similar types of provisions that were implemented.

I think, specifically, one of the most relevant would be San Francisco's provision pursuant to section 39930(j) and then also, to some extent, the Power and Water Resources Pooling Authorities calculation that was under 39930(i).

But as we're looking at that, it's also important to note that the subdivision (k), the section that SB 591 was adopted under, is a completely unique and stand-alone provision.

And so, we need to make sure that it's being implemented pursuant to its language and gets implemented correctly.

As far as some of the responses to the questions, on the first set of questions relating to determining if SB 591 applies, and that's something that we're still looking at. I think it's a complicated question.

I think that a multi-year averaging methodology seems to make a lot of sense to us. We're still determining if the seven years is appropriate, and if that’s the correct metric to go off of.

And then, also determining whether this would be done on an annual basis or on a compliance period basis, I think that’s also something we’re still taking a look at.

But stepping back from that, I think it’s important to recognize that that 50 percent language was really in there to designate that this is applying to Merced. I don’t think the Legislature intended that to be a metric, a performance metric that Merced was supposed to be meeting. It was to make sure that this was describing one specific utility.

And that 50 percent number I think describes typical operations for the Merced Irrigation District.

But, obviously, with some of the unique drought challenges, the way that the calculation might actually work on an individual basis is something that we’re still taking a lot at.

And like I said, that’s something we’ll provide a lot more detailed comments on, on the 28th.

And then on to the next question as far as if it does apply how the provision applies.

I think that it’s consistent with the Legislature’s intent to provide genuine relief to the community that’s served by the Merced Irrigation

District, as well as it’s consistent with the language of the statue that the RPS obligations apply to the portion of the load that isn’t being served by the X-Checker (phonetic) facility.

As far as some of the mechanics of how that would be implemented, I think that’s something that we can talk further with staff on and something that we’ll follow up with in our comments.

On the issue of the bucket limitations, that’s one of the places I think it’s useful to look at the San Francisco provision and how that was implemented.

And so, as I look through the initial statement of reasons and look at the legal, and policy justifications for why the San Francisco provision was implemented in the way it was, as far as bucket limitations, those all seem to apply equally to the Merced Irrigation District.

I think subdivision (k) of section 39930, is a stand-alone provision. I think it can be viewed as a stand-alone provision in the same way that San Francisco’s (j) subdivision can be viewed as a stand-alone provision.

There isn’t any express reference to the 39916 requirements.

And then, if you just think about it from a policy and practical perspective of where they would need to be complying with the bucket one requirements through, you know, a PPA, as a 20-year PPA or through ownership.

But if their hydro resources are varying so much from year to year, that adds a whole level of complexity.

Where, if they had three really great hydro years, they've now got all this excess bucket one, but because of the bundle requirements they would have to sell off at a huge loss as a bucket three product.

And so, given the variability from year to year of what their obligation is going to be, I think in the same that it would apply with San Francisco it makes sense to have them comply without regard to the bucket requirements.

And then, as far as the annual and then just some of the implementation issues, I think those are things that we're going to have to discuss with staff, what makes sense as far as when things are reported, what the forms look like, what documentation is going to be needed.

So, I think, obviously, there's going to be somewhat of a process as we move forward. So, I think we just look forward to working with staff and we'll elaborate on a lot of these issues in our comments on the 28th.

So, any questions?

MR. CAMACHO: I have a couple questions. So, could you discuss why not annually? I mean, I heard that you would prefer multi-average.

Well, one, if you prefer multi-average over how many years? That's the first question.

MR. WYNNE: Yeah, and I think that sort of the basis was the Power and Water Resources Pooling Authority, they only have pumping load, and so they were looking at it from a retail sales.

And so, when the whole process was going through, the previous legislative process, they were saying it was going to be difficult for them to have this extreme variation because their actual retail sales vary so much given on whether it's a drought year or whether it's a very wet year.

And so they asked for the seven-year averaging so that their retail sales could be averaged.

And I think as San Francisco went through, that seemed like a reasonable choice of the seven years when they were looking at how their provision would be implemented.

But I think that before we just latch onto that seven-year number, I think it would be useful to look at what makes sense from a policy perspective and what makes sense from what the statute -- how it’s structured, because that’s not in the statute.

And I think the goal of the statute is that this only applies to Merced. I think the purpose was that there wouldn’t be multiple different utilities that could take advantage of this. And that the assumptions of the legislation that they would still be getting the power from Merced were going to still be in place.

And so, I think as long as those things are true, I think it makes sense to adopt some sort of methodology to make sure that just because there’s a severe drought year they’re not going to get hit with what the legislation was designed to avoid.

And so, I think it’s just a matter of staff looking through the numbers of what makes sense and then just sort of from a policy perspective what makes sense.

MR. CAMACHO: That answers both questions, thank you.

MR. HERRERA: So, I have a question, Justin. So, drawing a comparison to San Francisco, I mean I think one thing that staff looked at, Energy Commission staff, was that on any given year that San Francisco’s entire electrical demand was being supplied by Hetch

Hetchy.

Whereas, at least my understanding right now, in Merced's case that their large hydro doesn't provide all their needs.

So, just looking at things factually, it appears that perhaps they may be a little bit different than San Francisco.

Whereas in San Francisco's case they typically do not need to procure any additional renewable resources because they're entire load is being supplied by Hetch Hetchy.

Whereas in Merced's case, on an average year, they will know that they will have to procure additional renewable resources, right?

So, I do think there are years where their entire load -- where Merced's entire load will be met by X Checker. And that's happened recently or, you know, almost all the way there.

So, in that sense it is similar.

And also, just as far as the items that I saw in the initial statements of reasons that wasn't -- the magnitude and the frequency wasn't a factor.

And so, it will be the same for them where it could be -- it is going to be all over the place. Even if on average it's lower, I think the same factors apply.

And I think we could provide some of the data of what the typical generation versus load looks like.

MR. HERRERA: So, yeah, I'd be interested in seeing that data. I mean if it's hard for a POU to predict what its needs are going to be in the future because of the varied amount of hydro generation that they acquire, it may be difficult to plan for that, and so you wouldn't have advance notice that you'd be -- you're going to be short, right?

MR. WYNNE: Yeah, exactly.

MR. HERRERA: Okay. Thank you.

MR. WYNNE: Thank you.

MS. ZOCCHETTI: Linda Johnson.

MS. JOHNSON: Good morning. I'm Linda Johnson. I'm representing the small POUs. We've been participating fully in the RPS process, the CEC's RPS process and have submitted comments before.

But the small POU group that we represent is an ad hoc group of very small publicly-owned utilities that were, for the most part, formed at the time of the energy crisis in California, with the intent of better controlling energy prices and providing economic development opportunities in their communities.

COMMISSIONER HOCHSCHILD: Can you identify, again, for our benefit, who's in that group?

MS. JOHNSON: The Cities of Cerritos, Moreno Valley, Corona, Rancho Cucamonga, Victorville, Pittsburgh Island Energy.

And they have different interests at different times, so these are kind of general comments related to topic two, which is the distributed generation issue.

We've previously submitted comments in general arguing for accommodations and flexible compliance measures due to the various factors that are unique to this group because they've been in business for such a short period of time, and because they're very small.

And so, they don't have some of the kinds of scale and flexibility to deal with the wholesale power markets.

But at this workshop we're providing comments in support of classifying distributed generation as PCC-1 because we think there's some unique opportunities and consistency with the economic development goals of this group that are very valuable to continue to implement the RPS policies in the State, and are consistent with the RPS policies in the States.

So, the expanded use of distributed generation systems fits well with the economic development business model. And we think it's also consistent with the future of the utility model.

These systems are based -- and what we're proposing is based on creating a partnership with customers to develop renewable resources which meet the requirements for PCC-1 resources, while also fulfilling the community's economic development goals.

We're going to be submitting written comments, getting more into the specifics of some of the questions that were asked, both in Attachment A and in the presentation, earlier.

So, I'm going to just keep this kind of general. We just want to emphasize that we consider the unique capabilities and goals of these small utilities to be really opposite to the old model of net metering and distributed generation, which seem to be the focus of some of the questions.

We're urging the CEC to affirm flexible policies to allow development of innovative options and facilitate what we believe is a future model based on extensive use of distributed generation with the cooperation and support of the utility.

Our proposed use of distributed generation to meet RPS requirements is not simply another name for net metering.

Instead, the partnership should be treated as a whole different approach, as a way of providing economic development incentives for new business, while providing the reliability and integrated technology solutions that are available to the utility and its diversified resource portfolio.

In the future of micro-grids, internet-operated equipment and built-in energy solutions, we see concepts like net metering going away because such mandates will no longer be required or necessary.

In such an environment, utility/customer partnerships, like the one we're asking the CEC to affirm will be absolutely essential.

To summarize some of our -- the answers to the questions that we anticipate presenting, the transactions are different from net metering programs because the title to the bundle that renewable energy passes -- resources passes to the utility, under contract with the customer or other owner of the distributed generation system, the bundled energy is delivered under separate metering arrangement.

The retail load to the customer will continue to be included in the utility's total retail sales figure for calculation of RPS requirements since the retail load is independent of the generation the customer's selling to the utility.

And last, this is just a new approach to meeting State policies, encouraging distributed generation of renewables and economic development, for that matter, too, and is a voluntary partnership between the utility and the customer, not a mandate.

Are there any questions? Thank you.

MS. ZOCCHETTI: Thank you, Linda.

Next is John Pappas.

MR. PAPPAS: Good morning Commissioner and good morning Commission staff.

PG&E appreciates the opportunity to comment on the issues and questions raised by CEC staff regarding the planned revisions to the RPS enforcement rules for POUs.

We intend to file written comments on these topics that are more specific. And in addition, we'll provide additional background in cases where the CPUC has interpreted the RPS statute on these issues.

Our overriding concern on the topics addressed herein are that the rules should be applied fairly and consistently across all load-serving entities, whether they're retail sellers under the CPUC's jurisdiction, or local, publicly-owned utilities.

In addition, PG&E believes that in the interest of achieving the State's over-arching RPS goals in a nondiscriminatory way, a statutory exemption should be strictly limited to the Legislature’s language and intent, and should not be broadened through administrative implementation.

The only specific topic that I’ll talk about today is the last one on dynamic transfer agreements.

PG&E’s view is that the legislation is clear that the arrangements to dynamically transfer output into a California balancing authority, whether by pseudo-tie or dynamic schedule, qualify for portfolio content category one treatment provided that the facilities are dynamically transferred into a California balancing authority.

It looks like the staff’s concern on this matter is that a facility that dynamically scheduled into a balancing authority, other than a California balancing authority, may count as PCC-1.

And we believe that actually that concern is misplaced since the statute specifically requires and the regulations should reflect that, that the dynamic transfer is into a California balancing authority.

So, I think the problem is solved, assuming that the dynamic transfer is to a California balancing authority.

As far as other dynamic -- I mean treating other products that are transmitted in real time, through other scheduling arrangements, for those it is reasonable to require verification of the hourly schedule and E-tags with regard to PCC-1 claims.

However -- but in the case of a dynamic transfer that’s going into a California balancing authority, those things are, per se, PCC-1 and should not need to be documented through administratively burdensome hourly, or sub-hourly verification requirements.

So, just to sum up, the statute does not distinguish between types of dynamic transfers. Accordingly, the regulations should treat dynamic scheduling no differently than pseudo-tie arrangements.

Thank you for the opportunity to comment and does anyone have any questions?

COMMISSIONER HOCHSCHILD: Yeah, I just wonder if you could comment just more broadly on -- I understand, you know, generally the goal consistent in application of the law.

MR. PAPPAS: Uh-huh.

COMMISSIONER HOCHSCHILD: But for the specific circumstance of the small POUs which are, you know, in many cases some of these POUs have one staff person running them.

MR. PAPPAS: Yeah.

COMMISSIONER HOCHSCHILD: Could you just comment on, you know, your thoughts on their proposal on this PCC-1 idea?

I mean do you feel there should be leeway there for the different circumstances or, really, in all cases everything should be identical, essentially?

MR. PAPPAS: I think it should be identical. I mean, frankly, if there is a movement to categorize behind-the-meter RECs, shall we say, as PCC-1, I mean I think that should be available to anyone in the State.

I don’t see that you can sort of parse it out between different entities, whether they’re very small or, you know, a little bit bigger, or medium size, so on and so forth.

And I think that’s sort of a dangerous area to try to draw the line there.

I mean, you know, there are legislative exemptions that are written into the legislation, such as the 591 that we talked about. I mean if it’s in the legislation, that’s a different matter.

But I think in this case it should be applied equally. And if it turns out that the CEC decides to go this route, I think folks would strongly argue that the CPUC should do the same thing.

MR. HERRERA: Thank you. So, John, I’ve got two questions just to follow up to Commissioner Hochschild's questions.

Does PG&E own DG? Do you have situations or systems where you employ DG on PG&E facilities, say like a maintenance facility?

And because it's an IOU-owned DG system, would you then characterize that as PCC-1, even though that power may be used on site?

MR. PAPPAS: I don't think we actually have --

MR. HERRERA: Okay.

MR. PAPPAS: I mean I'm not sure. We do have solar and most of it is just going into the system, and we've got some fairly large projects which are clearly not DG.

We have a few facilities in San Francisco, I think at a service yard, and also I think at the ball park that actually are PCC-1 because they do provide power to the grid.

So, I don't know that we have any that are behind the meter.

Certainly, if they were behind the meter, under the current rules then those would be considered PCC-3.

MR. HERRERA: Okay, interesting.

And then my second question deals with dynamic transfer. So, I guess our understanding is that there is a difference between pseudo-tie facilities and facilities that transfer electricity through a pseudo-tie arrangement versus a dynamic schedule.

And so, we were a little concerned that in the latter there could be situations where perhaps the electricity isn't being scheduled for consumption in a California balancing authority, you know, on an hourly basis, such as real-time electricity in PCC-1.

I mean, in that circumstance does it make sense to treat that electricity product differently from other PCC-1 products?

MR. PAPPAS: I mean if it's not -- if the dynamic transfer is to schedule it into a California balancing authority, then that should clearly be PCC-1.

So, sort of setting that aside, if you're talking about a situation where you have a dynamic transfer, but it's not being scheduled, so it's scheduled into some entirely different balancing authority --

MR. HERRERA: Right.

MR. PAPPAS: -- I suppose that that -- you know, that shouldn't apply.

But as long as the other arrangement clearly is PCC-1 and you don't need to go to the hourly verification, the other arrangement being dynamic transfer -- dynamic schedule into a California balancing authority, that should always be PCC-1.

MR. HERRERA: Thanks.

MR. PAPPAS: Yeah. All right thank you.

MS. ZOCCHETTI: Thank you, John.

Tony Goncalves.

MR. GONCALVES: Good morning Commissioner and staff. I'd like to thank you for the opportunity to speak before you today. I've waited a year to be able to come up and actually speak to you, and try to influence any decisions.

I'm going to speak just to topic five today. We do have some written comments. I've actually already sub mitted those because I won't be around through the deadline.

To start, I mean the simple answer to the question is, yes, we should allow these short-term contracts that are amended to be long-term contracts, to not be subtracted from the excess procurement calculation.

But I don't think this quite goes far enough. I think perhaps it's meant here, but you address just the short-term contracts.

I think the amendment provision should also apply to long-term contracts. So, if you have a long-term contract that gets amended to an extended term, that you should still be able to count that as a long-term contract and not have that amendment trigger a new contract.

And along the same lines, I’m going to kind of hit a couple of things under excess procurement that weren’t directly address here, in the question.

But I also believe that you should allow, or ask the Commission to consider allow amendments to the capacity, or generation or RECs under the contract at least for short term to also not trigger a new contract.

And, you know, this comes into the case where you’ve got some facilities that are looking at, or POUs looking at employing an excess procurement strategy. If you have any contract that is short term, it basically destroys your excess procurement strategy.

And under certain circumstances you may have situations, especially towards the end of a compliance period, whether either you have contracts that you have, that are long term, that for some reason either under-procure, you have loss of generation for some reason, fire, storm damage, or you just have some unexpected load growth that somehow got unaccounted for. Right at the end somebody comes in who didn’t tell you until the last minute.

And it’s difficult to -- or it can be difficult to get a long-term contract under that situation, especially if you need it for a short term.

Under the case where you’ve got fire or damage, where the facility’s going to be down for maybe a year or two, at the most, it doesn’t make a lot of sense to go out and get a long-term contract when you only need generation for a couple of years.

So, under that situation, I respectfully request that the Commission consider not only allowing amendments to long-term contracts for short periods, you know, adjusting the generation to cover that short-term loss, but also if you would consider allowing short-term contracts, under very specific situations.

So, under the case where you’ve lost generation, especially as you get towards the end of a compliance period to consider allowing contracts that are short term in base, under very specific circumstances and you’d have to demonstrate that you already had that generation, you had generation on a contract to meet your obligation, to perhaps allow those to not be subtracted out of the excess procurement calculation.

I mean under those circumstances and -- I mean as a POU, you basically would have two options. One is throw that strategy completely out the door.

The other option would be to simply look at the provisions of a waiver of time of compliance.

Now, if you had the generation under long-term contracts, already, and you lost it at the end of the compliance period, I think you would have all the reasonable justifications to apply for a waiver of time of compliance.

A waiver of time of compliance basically ends up with less generation because you get -- you don't have to purchase that additional generation and you still meet the provisions of the RPS requirements.

Now, from Roseville's perspective, our preference is always going to be to meet the RPS requirements based on achieving the percentages of renewables that are in the regulations.

But if we move forward with an excess procurement strategy and we're faced with the situation of either throwing that strategy completely out the door, or filing for a waiver of time of compliance, we're likely going to do the waiver of time of compliance.

We've found -- you know, we did -- we were in the situation of having to procure short-term contracts at the end of the first compliance period. And while we were not doing the excess procurement at that point, we did find it very difficult to acquire even short-term contracts under a short amount of time, let alone trying to get a long-term contract that would most likely require going to either a board or city council, which cuts down the amount of time that you have to deal with that.

So, I'd respectfully request that the Commission consider that.

The other item that I'd like to bring up also falls under the excess procurement and that is the subtraction of short-term PCC-3 from the excess procurement calculation.

I do understand the provisions and the rationale on why long-term contracts were reintroduced in the last 15-day language, when the regulations were adopted.

And I won't make any arguments for PCC-1 or PCC-2, but PCC-3 really is designed to be excess energy. And not only is it difficult to find a PCC-3 contract that is out there for ten years, but it's hard to imagine why an individual facility or developer would be willing to commit ten years' of RECs only when they can go out and try to sell their contract -- especially going out that long, try to sell their energy at a PCC-2 or PCC-1 that is certainly much more lucrative.

And no facility is ever going to be built or operated on PCC-3 alone, it just isn't feasible.

Now, we've been trying to find long-term PCC-3 and it hasn't been easy. What we've seen, typically is looking like the prices are going up considerably, especially in the outer years, which we'd expect.

So, we're really looking at, under this requirement for long-term PCC-3, in order to qualify for excess procurement, that we're probably going to see a three to six time increase in the cost of PCC-3 RECs over the ten-year term in order to be able to get a ten-year contract.

And with that, I'll conclude my comments and take any questions you might have.

COMMISSIONER HOCHSCHILD: One question, and this is for Tony, how would you avoid any kind of gaming, you know, if -- you know, to your point. I mean that would be my concern?

MR. GONCALVES: Which one, on short-term contracts or --

COMMISSIONER HOCHSCHILD: Yeah.

MR. GONCALVES: You know, that one I think you can put in provisions that require a POU to demonstrate that they had under contract enough generation, under long-term contracts, that would have met their obligations.

And so, you can demonstrate, you know, if you have a facility that goes down for a fire, or you have a facility that just for some reason under-performs, or the other example is you have a new facility that's just coming online, you're expecting it to come online at the beginning of, say, 2016 for the third compliance period and you count a year's worth of generation and that facility doesn't start until June, July, August. And so, you've lost half a year's worth of generation.

Well, you've got that facility going forward to meet your obligations and you don't need another ten-year contract because now you're way over-procuring and adding additional costs to your ratepayers.

Those are the kinds of situations where you can put in some requirements to demonstrate that you would have met that need or demonstrate under the other circumstance where you've got -- your load increases, you know, unexpectedly.

You have historical load and you have load forecasts that show your projected loads and suddenly you have a huge bump. You've got a big company that comes in. And if you're fairly small, it doesn't take a lot to throw that load off.

And while you'd want to get a long-term contract to account for that, trying to do that in a short amount of time might be difficult. So, allowing a short-term contract to meet that near-term increase in load, say a year or two, you can limit the amount of time for which you can do those short-term contracts, and then procure -- take your time to procure a long-term contract so you're not -- you know, developers know if you're at the end of a compliance period and you're out looking for generation, they know you're desperate and you typically will pay a little bit more.

And we did find that at the end of the first compliance period. You know, in our example it was we started six months before the end of the year, working on developing it.

I'll tell you that our last contract was signed on December 20th, and that was the last piece we needed. We did meet our obligation, but it took us until December 20th to be able to get all the contracts we needed.

COMMISSIONER HOCHSCHILD: Thank you.

MR. CAMACHO: So, I have a question.

MR. GONCALVES: Yes.

MR. CAMACHO: So, on the question about amendment to contracts --

MR. GONCALVES: Yes.

MR. CAMACHO: -- so you would agree that this type of amendment matters, right? So would you propose, then, a criteria to evaluate whether an amendment should make a contract, you know, a new contract or not?

And if so, how would that criteria look?

MR. GONCALVES: Well, under the extension of the term, I think just like taking a short term to a long term, I think extension of the term under, you know, just the length under, you know, the same generation RECs that you’re getting. I think those should be allowed.

I mean the goal is to get new generation online and to have it continue to operate.

And so, if we have a new facility, we sign a ten-year contract, we’ve helped bring that facility online and retain it online.

If we now take and we extent that contract, say, another five years, we’re continuing to help that facility remain online.

So, I think under extension of term that perhaps you don’t have a lot of requirements.

Now, the suggestion on increasing -- allowing for increase in the capacity for short term, that I think would be -- you put similar requirements to allowing short-term contracts.

Where, under specific circumstances -- because you may be able to -- again, you lose some generation because another contract under-performs, or has a fire and is out for a while, you know, perhaps you only need a year's worth of generation.

So, again, for increases in capacity I would suggest that being the short-term allowance to account for losses.

So, you kind of have the same provisions that you might put in for allowing short-term contracts.

MR. CAMACHO: Thank you.

MR. GONCALVES: Thank you.

MS. ZOCCHETTI: Thank you, Tony.

Bill Westerfield.

MR. WESTERFIELD: Good morning, Bill Westerfield with the Sacramento Municipal Utility District. Good morning Commissioner, good morning staff.

I'd just like to make some high-level comments about topic two, and that SMUD does support flexible contractual arrangements to all for all generation from DG systems in California to be counted as PCC-1, whether they're behind the meter or not.

SMUD has commented repeatedly in the drafting of the enforcement regulations that all electricity from DG systems, with their first points of interconnection, with distribution facilities of a California balancing authority, used to serve California load are legally PCC-1 resources under the statute.

We believe that's what the Legislature intended.

It seems that the notice has opened up that question, again, and so we urge the Commission to reconsider the exclusion of behind-the-meter generation as PCC-1. We think it should be PCC-1.

We think that these are all category one resources because, quite plainly, the statute says they are.

All that's required is that the system have its point of interconnection with a California balancing authority and that's satisfied by these DG systems.

So, we think that that plainly qualifies them as PCC-1 and that any contractual arrangements to enable that should be encouraged by the Commission.

We frankly don't understand the buy/sell back concern. These systems serve California retail customers. That's the point.

There is a fundamental -- this is the fundamental distinction and attribute of PCC-1 resources. The Legislature intended DG to be PCC-1.

So, we think the Commission should consider any contractual arrangements that give effect to that legislative intent.

So, I'd be happy to answer any questions.

MS. ZOCCHETTI: Thank you, Bill.

Are there any other folks in the room that wish to comment?

MR. WRIGHT: I thank you, Walker Wright with the Alliance for Solar Choice.

My colleague, Andy, covered most of what we want to say today or in further comments.

But just wanted to follow up on the fact that we're heartened by the comments from PG&E on consistency across the State, and also from the public power in terms of wanting behind-the-meter to go beyond what is currently, sincerely a second-class citizenship.

You know, from a national perspective, my company, Sunrun, we still don't understand the rules in California. Our investors do not understand the rules in California.

And as rooftop solar approaches a major drop in the ITC, changes in rate design, and we're at the end of the rebate program, it makes sense for there -- there has to be some value for these clean electrons.

An electron that goes from my rooftop down to my toaster must have RPS-qualified value in California, the way it does across the country.

And we have a team of, you know, REC transaction folks who are currently looking at even trying to do the paperwork for category three in California, and we're not doing it because of the hurdles from a bureaucracy stand point.

So, I urge consistency across the State. And I think starting right now, with the public power, would be a great start. Thank you.

MS. ZOCCHETTI: Thank you.

Any other comments from the folks in attendance?

All right, seeing none, we are looking at WebEx. I don't believe we have any comments through WebEx.

Okay, and then we're going to go ahead and unmute the phones. If you are a call-in participant, please just unmute your phone when you're ready to speak.

Let me know, Theresa, when we're unmuted. We are unmuted. Hello?

Hello, anyone on the phone wish to comment?

Going once -- it sounded like someone unmuted their phone, one more opportunity, any comments from the phone?

All right, hearing none I'm going to -- please go ahead and mute the phones again, Theresa. Thank you.

I'm going to put the schedule up just to remind everyone of kind of next steps. Again, the written comments, which we look forward to, I know many of you are planning to provide more details in your written comments and we really appreciate that.

We look very closely at those. Please submit them by July 28th. Note that the deadline is 4:00 p.m.

We would appreciate that you submit them both to the docket and to our staff's e-mail so that there's no delay in getting those comments to staff.

Please include the docket number and indicate the Renewables Portfolio Standard in the subject line. That really helps everyone.

Lucky Emily gets to have you contact her for questions or comments.

I think that we're anticipating that the next steps will be that you will see draft language. In the formal rulemaking process, we'll begin with that.

So, we do look forward to working with many of you, as was said in the comments on, you know, individual meetings, with discussions on how we should move forward.

And we really appreciate your participation today.

And thank you, Commissioner Hochschild for making the time to join us.

And with that, I think we are adjourned. Have a really nice weekend.

(Thereupon, the Workshop was adjourned at 10:41 a.m.)

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REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of August, 2014.

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Barbara Little
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